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THE IMPROVEMENT OF FLEXIBILITY AND EFFICIENCY OF THERMAL POWER PLANTS UNDER VARIABLE OPERATION CONDITIONS

Doctoral Thesis

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ABSTRACT

The implementation of market mechanisms, different support schemes for renewable energy resources and large-scale integration of intermittent generation in energy production process have a negative effect on running conditions of fossil fuel thermal power plants (TPPs) and their future. The operation of fossil fuel TPPs is shifted from based load operation to cycling, which is adverse from technical, economic and environmental point of view. Moreover, the thermal power plants are partly or not at all adapted to new running conditions. This leads to the efficiency decrease and more frequent trips and outages of power plants. Thus, the flexibility level of fossil fuel TPPs should be increased to adapt their operation to new running conditions and increase their efficiency, flexibility and profitable operation as well as prevent from mothballing.

There are different measures to increase the flexibility of thermal power plants. The Doctoral Thesis provides the mathematical description of transient modes of the combined cycle gas turbine (CCGT) power plants. The *EM&OM* (*Evaluation Model and Optimisation Model*) approach was developed to optimise its operation by shifting start-up *"backward"* and shutdown *"forward"*. The general algorithm was developed to provide the technical and economic justification of technologies, which are aimed at increasing the flexibility level of fossil fuel TPP. The algorithm was adapted to three technologies: air cooling, electric boiler and heat storage tank. The developed measures were approbated on the example of Riga TPP-2 plant in Latvian site conditions.

The presented measures can be adapted to other types of thermal power plants. The obtained results can also be used by JSC Latvenergo to decide about the necessity to increase the flexibility level of Riga TPP-2 and by researchers of Riga Technical University to use them as input data for the developed optimisation programme of power plants.

ANOTĀCIJA

Tirgus mehānismi, atjaunīgo energoresursu atbalsti un mainīga ģenerācija atstāj negatīvu ietekmi uz fosilo kurināmo termoelektrocentrāļu (TEC) darbības režīmiem un to tālāko eksistenci nākotnē. TEC darbības režīmi tiek izmainīti no bāzes un cikliskiem režīmiem (jauni darbības režīmi). Bāzes režīma fosilā kurināmā termoelektrostacijas daļēji vai vispār nav adoptētas cikliskiem režīmiem. Tas noved pie TEC efektivitātes samazināšanas, biežiem avāriju atslēgumiem un apturēšanām. Tādējādi bāzes režīma termoelektrocentrāļu elastīguma līmeni ir nepieciešams palielināt, lai adaptētu to darbību jauniem darbības apstākļiem, palielinātu efektivitāti, elastīgumu, darbības rentabilitāti un novērstu no agrīnas iekonservēšanas, kā arī nodrošinātu drošu mainīgas ģenerācijas integrāciju enerģijas ražošanas procesā.

Ir dažādi pasākumi, lai uzlabotu termoelektrostaciju elastīgumu. Darbā ir izstrādāts gāzes turbīnu kombinēta cikla elektrostaciju pārejas režīmu matemātiskais apraksts. *EM&OM* (no angļu valodas *Evaluation Model and Optimization Model*) pieeja ir izstrādāta, lai optimizētu TEC darbības režīmus bīdot palaišanas *"atpakaļ"* un apturēšanas *"uz priekšu"*. Vispārējais algoritms ir izstrādāts, lai realizētu tehniski ekonomisko pamatojumu tehnoloģijām, kuras nodrošina TEC elastīguma un efektivitātes līmeņa palielināšanu. Algoritms tiek adoptēts trim tehnoloģijām: gaisa dzesēšanas, elektriskais katla un siltuma akumulatora. Darbā izstrādātie un aprakstītie pasākumi izmēģināti uz AS Latvenergo ražotnes Rīgas TEC-2 piemēra, ievērojot Latvijas klimatiskos apstākļus.

Izstrādātos pasākumus var adoptēt citiem termoelektrocentrāļu veidiem. Darbā iegūtie rezultāti arī var būt noderīgi AS Latvenergo, lai lemtu par nepieciešamību palielināt Rīgas TEC-2 elastīgumu, un pētniekiem no Rīgas Tehniskās universitātes, kuri var izmantot iegūtus rezultātus kā izejas datus elektrostacijas optimizācijas programmatūras izstrādei.

LIST OF ABBREVIATIONS

Abbreviation	Explanation
AC	Absorption Chiller
BB	Biomass Boiler
CCGT power plant	Combined Cycle Gas Turbine Power Plant
CHP plant	Combined Heat and Power Plant
COP	Coefficient of Performance
DH	District Heating
DH ECO	District Heating Economizer
DHS	District Heating System
EB	Electric Boiler
EC	Evaporative Type Chiller
EM&OM	Evaluation Model and Optimisation Model
EPC Contractor	Engineering, Procurement and Construction Contractor
FC	Fogging Type Chiller
FL	Full Load
GFB	Gas Fired Boiler
GHG	Greenhouse Gas
GT	Gas Turbine
HOBs	Heat Only Boilers
HRSG	Heat Recovery Steam Generation
ICE power plant	Internal Combustion Engine Power Plant
IRR	Internal Rate of Return
JSC	Joint-stock Company
MC	Mechanical Type Chiller
NP market	Nord Pool Market
NPV	Net Present Value
OCGT power plant	Open Cycle Gas Turbine Power Plant
O&M costs	Operation and Maintenance Costs
PES	Primary Energy Savings
PV	Photovoltaic
RES	Renewable Energy Resources
SCPC power plant	Supercritical Pulverized Coal Power Plant
TES system	Thermal Energy Storage System
TPPs	Thermal Power Plants
UC	Unit Commitment

CONTENT

1 INTRODUCTION

1.1. Topicality of the Research

Thermal power plants (TPPs) seem to be an attractive option because they can deliver a variety of energy, environmental and economic benefits. Moreover, thermal power plants produce energy where it is needed, avoid waste heat and reduce losses in transmission and distribution networks [1]–[3].

The implementation of market mechanisms, different support schemes (such as feed-in tariffs) for renewable energy resources (RES) and large-scale integration of intermittent generation (solar photovoltaic (PV) and wind energy) in the energy production process have changed [4]–[7].

- The running conditions of fossil fuel thermal power plants, i.e., the shifting from base load operation to cycling. It is the operation under variable condition, such as variable load of intermittent generation or fluctuation of electricity price. Thermal power plants are partly or entirely not adapted to the cycling operation, which leads to a decrease in their efficiency, more frequent trips and outages.
- The role of fossil fuel thermal power plants, i.e., the secure integration of intermittent generation in energy production process and provision of regulation services to the transmission system operator instead of electrical and heat energy supply in line with its demand. This promotes the mass closing or mothballing of fossil fuel TPPs due to surplus of generation capacity, thus threatening the security of energy supply.

S. Lüdge emphasised in [8] that *"Out of the three pillars (environment, cost competitiveness and security of supply) describing the energy sector triangle only one is developing positively. This is the environmental part. ... The other two pillars (cost competitiveness and security of supply) are developing in the wrong direction. The economic situation for conventional power plants is so bad that a lot of them will have to shut down permanently in the coming years and naturally there won't be any new projects within this framework. Flexibility especially from fossil fuel fired power plants is not only needed but is the success factor for the whole energy turn around".*

The flexibility of fossil fuel TPPs is necessary not only today, but also within the next decades [2], [8]–[10] for the following reasons:

- to adapt existing generation to new running conditions and provide its efficient, flexible and profitable operation;
- to ensure the secure integration of intermittent generation in energy production process and to ensure a stable energy system;
- to achieve the goal of the European Commission concerning renewable energy sources and energy efficiency.

There are different measures to increase the flexibility of fossil fuel thermal power plants from expensive to cost-neutral [4], [11]. First, new running conditions of TPPs should be analysed to evaluate the bottlenecks of a cycling operation. Second, the appropriate measures should be proposed from the technical and economical point of view. Third, the beneficial measures should be implemented and unprofitable ones declined. Thus, the author of the Doctoral Thesis has developed the following new methodologies and mathematical models:

- a mathematical description of transient modes to identify the parameters of transient modes of combined cycle gas turbine (CCGT) power plant and the bottlenecks of cycling operation
- *EM&OM (Evaluation Model and Optimisation Model) approach* for operation mode optimisation;
- a general algorithm for technical and economic justification of technologies aimed at increasing the flexibility of thermal power plants.

All these developments were approbated on the example of Riga TPP–2 and Latvian site conditions.

1.2. Hypothesis of the Doctoral Thesis

It is necessary and possible to adapt fossil fuel TPPs to new running conditions (cycling) in order to increase their efficiency and operation profitability and prevent them from mothballing.

1.3. The Aim of the Doctoral Thesis

The aim of the Doctoral Thesis is to investigate new running conditions of thermal power plants and propose measures to improve flexibility and efficiency of thermal power plants under variable operation conditions.

1.4. The Tasks of the Doctoral Thesis

To achieve the aim of the Thesis, the following tasks have been set:

1) to investigate the concept of flexibility, as well as significance and necessity of flexibility;
2) to overview the measures to increase the flexibility and efficiency of thermal power plants;
3) to provide the mathematical description (mathematical models) of CCGT power plant transient modes (start-up, shutdown, warm state preservation);
4) to develop an approach to optimise the operation of thermal power plant;
5) to develop a general algorithm for technical and economic evaluation of technologies (air cooling, electric boiler and heat storage system), which are aimed at increasing the flexibility level of the thermal power plant.

1.5. Scientific Novelty

The mathematical description of transient modes of combined cycle gas turbine power plants has been provided.

EM&OM approach has been developed for operation mode optimisation of thermal power plants by shifting start-up *"backward"* and shutdown *"forward"*.

The general algorithm has been developed for technical and economic evaluation of technologies, which are aimed at increasing the flexibility level of thermal power plants. It has been adapted to three technologies (air cooling, electric boiler and heat storage system); as a result, three methodologies for certain technologies have been developed.

The mathematical description of transient modes, the general algorithm for technical and economic evaluation of technologies as well as *EM&OM approach* have been approbated on the example of Latvian site conditions and operation patterns of Riga TPP-2.

1.6. Practical Significance of the Research

The developed *EM&OM approach* and the general algorithm as well as its implementation in different technologies can be adapted to other thermal power plants, which operate under variable running conditions. The developed algorithm has practical application. It has been used for technical and economic evaluation of projects developed by *JSC Latvenergo*. The projects include the installation of thermal storage tank and gas turbine modernisation (*OpFlex* solution) at CCGT-2/2 unit of Riga TPP-2, and the installation of exhaust gas condensing economizer at the heat only boiler of Riga TPP-1. The *OpFlex* solution and exhaust gas condenser economizer have been installed and are in use. The developed algorithm was used to develop the feasibility study for the heat storage system and to submit the application for European Union co-financing (3.75 million €). The co-financing for the construction works of heat storage system at Riga TPP-2 by the end of 2020 was approved. Currently the procurement procedure is conducted to select the candidate for the EPC (Engineering, Procurement and Construction) contractor for the development of technical design and for further construction of heat storage system.

The results of the Doctoral Thesis can be used by *JSC Latvenergo* to evaluate different options for the improvement of flexibility and efficiency of its thermal power plants.

Moreover, the obtained results can be used as input data of power plant optimisation programme developed by the researchers of *Riga Technical University*.

1.7. Volume and Structure of the Doctoral Thesis

The Doctoral Thesis is written in English language. It comprises eight chapters, thirty-three sections, eighteen subsections, conclusions and a bibliography with 134 reference sources. It has been illustrated by 61 figures and 20 tables. The volume of the Thesis is 103 pages. Chapter 1 provides the information about the topicality and hypothesis of the Thesis, formulates the aim of the research and tasks to be fulfilled. Scientific novelty and practical significance of the Thesis are also presented. The author's scientific works are listed. Chapter 2 provides an overview of cycling and flexible operation of fossil fuel thermal power plants. Types of cycling operation, their impact on technical resources of equipment and costs are described. The parameters of flexible operation and measures to increase the flexibility level of fossil fuel thermal power plants are listed. The comparison of the flexibility level of TPPs is performed. The illustration of shifting from based load operation to cycling is presented on the example of Riga TPP-2 (the investigated object). Chapter 3 presents the developed theoretical mathematical models of transient modes and their practical application. Chapter 4 describes the developed approach to optimise the fossil fuel power plant cycling running conditions and provides its practical application. Chapter 5 introduces the general algorithm for technical and economic justification of technologies, which are used to increase the flexibility level of the cogeneration power plant. Chapters 6, 7 and 8 present the adaptation of the algorithm to three technologies (air cooling, electric boiler and heat storage system) with practical application. In the end, the main results of the Doctoral Thesis are summarised.

1.8. Scientific Work

1.8.1. International Scientific Conferences

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

1. 58th International Scientific Conference on Power and Electrical Engineering of Riga Technical University (RTUCON), 12–13 October 2017, Riga, Latvia.
2. 2017 IEEE International Conference on Environment and Electrical Engineering and 2017 IEEE Industrial and Commercial Power Systems Europe (EEEIC / I&CPS Europe 2017), 6–9 June 2017, Milan, Italy.
3. 57th International Scientific Conference on Power and Electrical Engineering of Riga Technical University (RTUCON 2016), 13–14 October 2016, Riga, Latvia.
4. 2016 IEEE International Conference on Environment and Electrical Engineering (EEEIC 2016)", 7–10 June 2016, Florence, Italy.
5. 2015 IEEE 5th International Conference on Power Engineering, Energy and Electrical Drives (POWERENG), 11–13 May 2015, Riga, Latvia.

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

1. Hydro 2015 International Conference and Exhibition. Advancing Policy and Practice, 26–28 October 2016, Bordeaux, France.
2. 56th International Conference of Riga Technical University "Scientific Conference on Economics and Entrepreneurship SCEE'2015", 14–16 October 2015, Riga, Latvia.
3. REHVA Annual Conference "Advanced HVAC and Natural Gas Technologies", 6–9 May 2015, Riga, Latvia.

1.8.2. Local Conferences

4th Practical and Scientific Conference "Energy-efficient Solutions to District Heating" organised by JSC Rigas Siltums, 1 July 2016, Riga, Latvia.

1.8.3. Publications

The results of the research have been published in conference proceedings and in scientific and popular scientific journals.

Full-text articles published in the conference proceedings:

1. **Ivanova, P.,** Sauhats, A., Linkevics, O. Cost-Benefit Analysis of Electric Boiler at Combined Heat and Power Plants. In: *2017 IEEE 58th International Scientific Conference on Power and Electrical Engineering of Riga Technical University (RTUCON): Proceedings*, Latvia, Riga, 12–13 October 2017. Piscataway: IEEE, 2017, pp. 1–6, ISBN 978-1-5386-3847-7, e-ISBN 978-1-5386-3846-0, doi:10.1109/RTUCON.2017.8124747.
2. **Ivanova, P.,** Linkevics, O., Sauhats, A. Mathematical Description of Combined Cycle Gas Turbine Power Plants' Transient Modes. In: *2017 IEEE International Conference on Environment and Electrical Engineering and 2017 IEEE Industrial and Commercial Power Systems Europe: Conference Proceedings*, Italy, Milan, 6–9 June 2017. Piscataway: IEEE, 2017, pp. 61–66, ISBN 978-1-5386-3918-4, e-ISBN 978-1-5386-3917-7, doi:10.1109/EEEIC.2017.7977405.
3. **Ivanova, P.,** Linkevics, O., Sauhats, A. Cost-Benefit Analysis of CHP Plants Taking into Account Air Cooling Technologies. In: *2017 IEEE International Conference on Environment and Electrical Engineering and 2017 IEEE Industrial and Commercial Power Systems Europe: Conference Proceedings*, Italy, Milan, 6–9 June 2017. Piscataway: IEEE, 2017, pp. 55–60, ISBN 978-1-5386-3916-0, doi:10.1109/EEEIC.2017.7977404.
4. **Ivanova, P.,** Sauhats, A., Linkevics, O. Towards Optimization of Combined Cycle Power Plants' Start-ups and Shut-down. In: *2016 57th International Scientific Conference on Power and Electrical Engineering of Riga Technical University (RTUCON 2016): Proceedings*, Latvia, Riga, 13–14 October 2016. Piscataway: IEEE, 2016, pp. 23–28, ISBN 978-1-5090-3732-2, e-ISBN 978-1-5090-3731-5, doi:10.1109/RTUCON.2016.7763081.
5. **Ivanova, P.,** Sauhats, A., Linkevics, O., Balodis, M. Combined Heat and Power Plants Towards Efficient and Flexible Operation. In: *2016 IEEE 16th International Conference on Environmental and Electrical Engineering (EEEIC)*, Italy, Florence, 7–10 June, 2016. Piscataway: IEEE, 2016, pp. 2434–2439, ISBN 978-1-5090-2321-9, e-ISBN 978-1-5090-2320-2, doi:10.1109/EEEIC.2016.7555874.
6. Kunickis, M., Balodis, M., Linkevics, O., **Ivanova, P.** Flexibility Options of Riga CHP-2 Plant Operation under Conditions of Open Electricity Market. In: *2015 IEEE 5th International Conference on Power Engineering, Energy and Electrical Drives (POWERENG)*, Latvia, Riga, 11–13 May 2015. Riga: Riga Technical University, 2015, pp. 548–553, ISBN 978-1-4799-9978-1, doi:10.1109/PowerEng.2015.7266375.

Articles in scientific journals:

1. **Ivanova, P.,** Sauhats, A., Linkevics, O. District Heating Technologies: Is it Chance for CHP Plants in Variable and Competitive Operation Conditions?. *IEEE Transactions on Industry Application*, 2018, ISSN 0093-9994, e-ISSN 1939-9367, doi:10.1109/TIA.2018.2866475 (*In press)*.

2. **Ivanova, P.,** Grebess, E., Linkevics, O. Optimisation of Combined Cycle Gas Turbine Power Plant in Intraday Market: Riga CHP-2 Example. *Latvian Journal of Physics and Technical Sciences*, 2018, 1, pp.15–21, doi:10.2478/lpts-2018-0002.
3. **Ivanova, P.,** Grebess, E., Mutule, A., Linkevics, O. An Approach to Optimize the Cycling operation Of Conventional Combined Heat and Power Plants. *Energetika*, 2017, 63 (4), pp.127–140, doi:10.6001/energetika.v63i4.3621.
4. Linkevics, O., **Ivanova, P.,** Balodis, M. Electricity Market Liberalisation and Flexibility of Conventional Generation to Balance Intermittent Renewable Energy – Is it Possible to Stay Competitive?. *Latvian Journal of Physics and Technical Sciences*, 2016, 53(6), pp. 47–56, ISSN 0868-8257, doi:10.1515/lpts-2016-0043.

Articles in popular scientific journals:

1. Stuklis, I., Linkevičs, O., **Ivanova, P.** Ārzemju pieredze siltuma akumulācijas sistēmas izveidei Rīgā. *Enerģija un Pasaule*, 2016, Nr.6, 44. –49.lpp., ISSN 1407-5911.
2. Balodis, M., Krickis, O., **Ivanova, P.** N-ERGIE siltuma akumulācijas realizācija Nirnbergas centralizētajā siltumapgādē. Enerģija un Pasaule, 2016, Nr.3, 40.–44.lpp., ISSN 1407-5911.

1.8.4. Other Publications

The author has also articles published in conference proceedings, book of abstracts and scientific journals, where different problems concerning the energy sector have been considered.

Full-text articles published in the conference proceedings:

1. Kunickis, M., **Ivanova, P.,** Pettersson, B. Rehabilitation of the Kegums 2 Hydropower Plant. In: *Hydro 2015: Advancing Policy and Practice: International Conference and Exhibition*, France, Bordeaux, 26–28 October 2016.
2. Zigurs, A., Kunickis, M., Linkevics, O., Stuklis, I., **Ivanova, P.,** Balodis, M. Evaluation of Exhaust Gas Condensing Economizer Installation at Riga CHP Plants. In: *Proceedings of REHVA Annual Conference 2015*, Latvia, Riga, 6–9 May 2015. Riga: RTU Press, 2015, pp. 149–154, ISBN 978-9934-10-685-9, e-ISBN 978-9934-10-717-7, doi:10.7250/rehvaconf.2015.021.

Article in popular scientific journals:

Balodis, M., Linkevičs, O., **Ivanova, P.,** Gavars, V. Latvijas primāro energoresursu patēriņš: vēsturiskās izmaiņas un prognozes. *Enerģija un Pasaule,* 2015, Nr.5, 15.–19.lpp., ISSN 1407-5911.

Article in the book of abstracts:

Balodis, M., Pocs, R., Skribans, V., **Ivanova, P.** Theoretical Justification of the Model of Evaluation of Renewable Energy Sources Integration on Fossil Fuel Energy Sources Operation Efficiency. In: 56th International Conference of Riga Technical University “Scientific Conference on Economics and Entrepreneurship” [CD-ROM]: SCEE ‘2015: Proceedings, Latvia, Riga, 14–16 October 2015. Riga: RTU Press, 2015, pp. 90–91, ISBN 978-9934-8275-3-2, ISSN 2256-0866.

Article in the reviewed edition "RTU Scientific Articles"

Balodis, M., Skribans, V., **Ivanova, P.** Development of a System Dynamics Model for Evaluation of the Impact of Integration of Renewable Energy Sources on the Operational Efficiency of Energy Supply Facilities: Theoretical Background. *Economics and Business*, 28, 2016, pp. 4–12, ISSN 2256-0386, e-ISSN 2256-0394, doi:10.1515/eb-2016-0001.

2 OVERVIEW OF CYCLING AND FLEXIBLE OPERATION

2.1. Definition of Cycling Operation and its Main Aspects

The running conditions of fossil fuel power plants have changed from base load operation to running conditions in cycling modes due to due to the implementation of market mechanisms, different support schemes for renewable energy resources and large-scale integration of intermittent generation (solar PV and wind energy) in the energy production process [12]–[14].

The cycling operation means operation with frequent unit load reduction or its full stop, when intermittent generation is available or price of electricity is low (variable running conditions) [15], [16]. The reason(s), aim(s) and benefits of cycling operation vary according to the geographical location of region, its situation in the energy system and economic development. The comparison of the situation in Latvia and Germany is presented in Table 2.1 [4].

Table 2.1

The Comparison of Situation in Latvia and Germany [4]

Parameters	Latvia	Germany
Reason of cycling operation of TPPs	The fluctuations of electricity price in the Nord Pool market	Intermittent generation variability
Aim of flexibility increase	Adjustment to the situation in the Nord Pool market	Integration of intermittent generation in the energy production process
Benefits of flexible operation	Obtaining additional profit, when electricity price is high. Ensuring profitable operation of the existing thermal power plants	Secure integration of intermittent generation in use. Opportunity to be *"the quickest"* and offer *"the first megawatts"*

Latvia does not have a plenty of intermittent generation sources. Cycling operation became common after Latvia had joined the Nord Pool (NP) market. It happened on 3 June 2013. Now fluctuations of electricity price determine the operation of power plants (Fig. 2.1 and Fig. 2.2) [15].

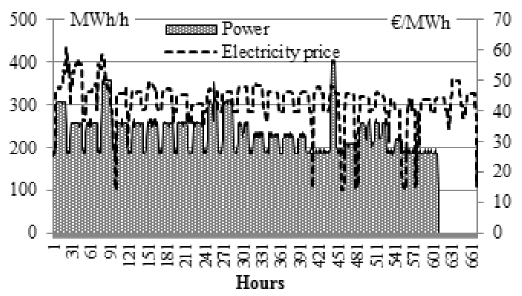


Fig. 2.1. Electricity generation profile of Riga TPP–2 plant from 1 February 2013 to 28 February 2013 [4].

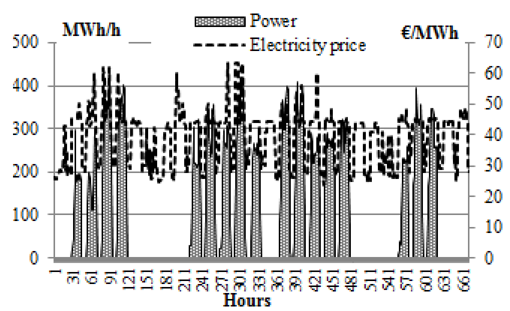


Fig. 2.2. Electricity generation profile of Riga TPP–2 plant from 1 February 2015 to 28 February 2015 [4].

In contrast, in Germany the main reason of cycling operation of TPPs is an availability of intermittent generation. The flexible thermal power plants provide a more secure integration of intermittent generation in the energy production process and participate in frequency control. For example, the availability of intermittent generation determines operation modes of *Sandreuth* TPP (Germany, Nuremberg) [17]:

1) When the power of intermittent generation is not enough, the TPP is loaded more. The produced electricity is delivered to the electrical power network and heat energy to the heating network. The surplus of heat energy is accumulated in the storage tank to the later delivery to the heating network (Fig. 2.3).

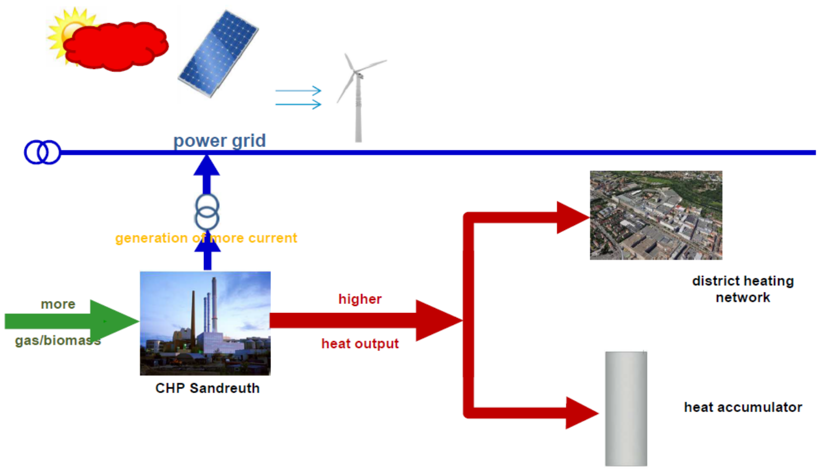


Fig. 2.3. The operation of *Sandreuth* TPP, when the intermittent generation is not available [18].

2) When the power of intermittent generation is enough, the load of *Sandreuth* TPP is reduced to the minimal value or power plant is shut down. The intermittent generation mainly provides the demand of electricity and storage tank – heat energy. TPP ensures the small part of heat energy and electricity demand (Fig. 2.4).

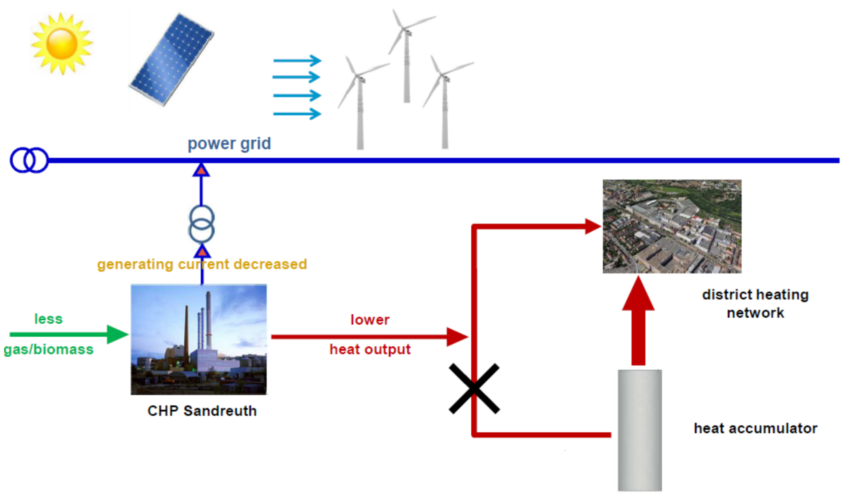


Fig. 2.4. The operation of *Sandreuth* TPP, when the intermittent generation is available [18].

2.1.1. Types of Cycling Operation

There are two types of cycling operation: with full shutdown or load reduction (Fig. 2.5).

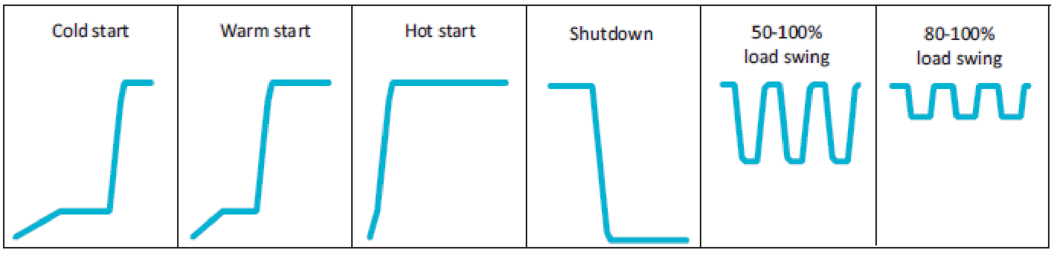


Fig. 2.5. Type of cycling operation [19].

There are three types of start-ups: cold, hot and warm (Fig. 2.5). The time unit offline or steam turbine temperature determines the type of start-up [15], [19].

Furthermore, the type of start-up determines the duration of start-up. The duration of hot, warm and cold start-ups in the context of 80–400 MW combined cycle gas turbine power plants is presented in Table 2.2. The time of start-ups for CCGT power plants with installed capacity of 250–400 MW is slightly longer than for 80–400 MW CCGT power plants [20].

Table 2.2

Types of Start-up [15], [19], [20]

Parameter	Unit	Hot	Warm	Cold
Time offline	H	< 8	8–72	> 72
Steam turbine temperature	° C	> 410	210–410	< 210
Start-up duration (for 80–400 MW CCGT power plants)	Minutes	40–60	80–120	120–170

In case of load reduction, different load swing is possible (Fig. 2.5): deep (50 %–100 %) or fractional (80 %–100 %). It is determined by the capability of equipment to reduce load in compliance with environmental requirements and profitable operation [19].

The warm state preservation process can be marked in cycling operation. The unit is not in operation but the energy is used to hold the unit in the warm state. It is common when the unit is shut down for the further hot or warm (more rarely) start-up. More detailed information about warm state preservation is available in Chapter 3.

The cycling operation with shutdown is more complicated than the operation with load reduction due to a start-up procedure. For example, Fig. 2.6 provides an overview of the starting procedure of CCGT power plants. It can be divided into four blocks [21], [22]:

1) Activities before ignition of gas turbine (GT). They are gas turbine and heat recovery steam generator (HRSG) preparation (purge of HRSG);
2) Actions to achieve steam and metal conditions. They are GT acceleration, synchronization and its operation to match temperature. HRSG is warmed and pressurized;

3) Activities to connect heat recovery steam generator and steam turbine. Gas turbine is operated to match necessary temperature. When the HRSG is ready, the steam turbine is accelerated and synchronized.
4) Actions to reach full load. Gas turbine controls the load. Heat recovery steam generator parameters correspond to requirements of steam turbine. Steam turbine loading.

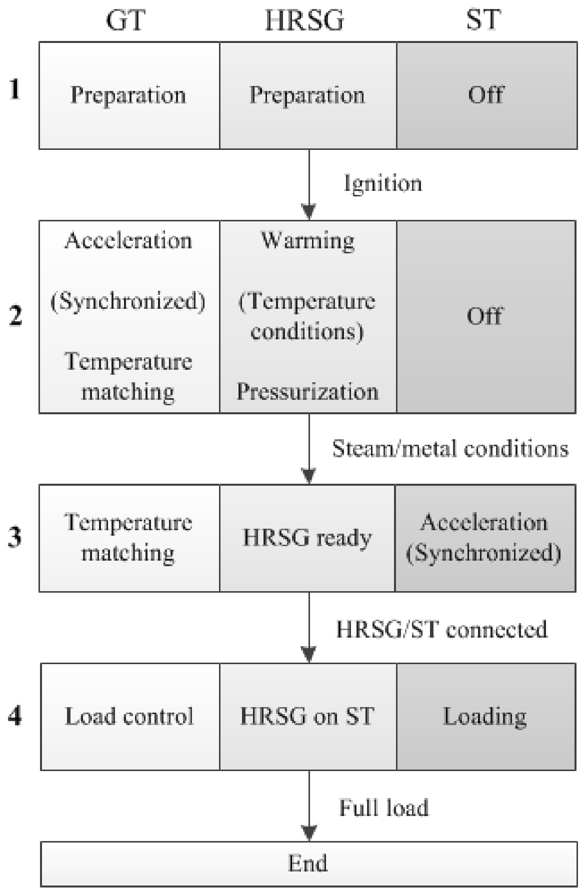


Fig. 2.6. Start-up procedure of CCGT power plant (developed by the author according to [21]).

The start-up procedure is described and illustrated in details in Chapter 3.

2.1.2. The Impact of Cycling Operation on Technical Resources of Equipment

The growing need for more cycling operations was not foreseen when many existing TPPs were designed and installed. Such operation reduces material lifetime and drives up operating costs.

The type of cycling operation (with load reduction or full shutdown) determines the range of its adverse influence on the operation of the power plant and its life time. The blue arrow in Fig. 2.7 demonstrates that operation with load reduction and shutdown followed by hot start-up has less adverse influence on thermal power plant equipment than the shutdown with warm or cold start-up.

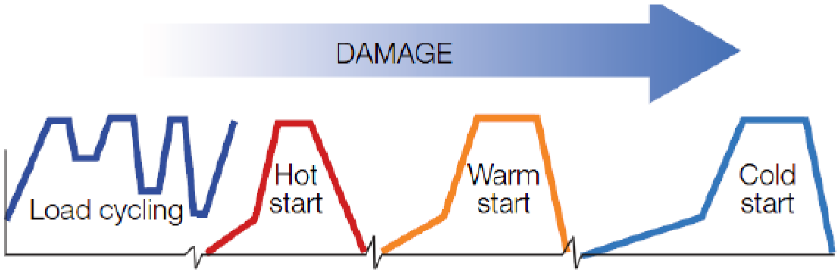


Fig. 2.7. The types of cycling operation [13].

The main damages of cycling mode are the following [13], [23]:

1) Fatigue is caused by repeated exposure to large temperature and pressure transients, and results in cracking or mechanical failure of structure.
2) Creep and fatigue interact in a synergistic manner, i.e., creep reduces fatigue life and likewise fatigue reduces creep life (Fig. 2.8). The creep–fatigue interaction makes the unit highly susceptible to component (mainly superheater, reheater and economizer headers) failure.

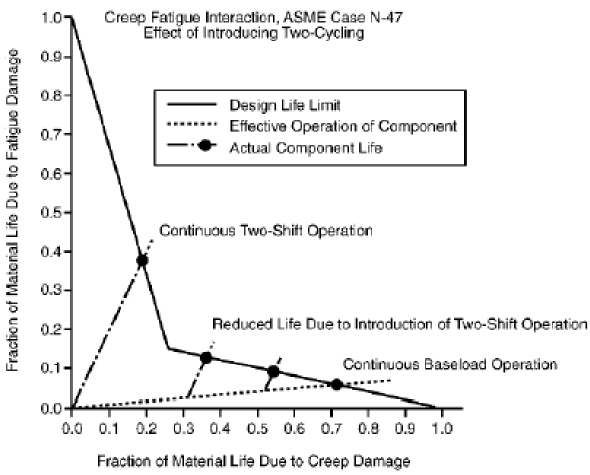


Fig. 2.8. Creep and fatigue interaction [13].

3) Different thermal expansion places the component under high stress causing cracks to initiate and mechanical fatigue to grow (Fig. 2.9).

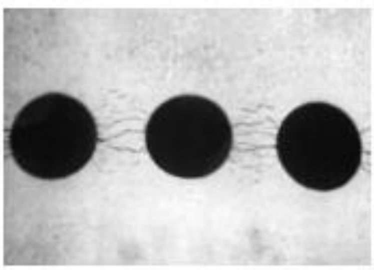


Fig. 2.9. Cracking seen from inside of the economizer header [13].

4) Start-ups and shutdowns can also cause oxide scales. The hard oxide particles entrained in the steam are carried through the turbine causing erosion of the turbine blades.
5) Thermal shocking of economizer headers occurs when cold feed water is introduced to warm headers when a unit is re-starting followed by an overnight shutdown. If this occurs on a regular basis, it will lead to internal fatigue cracking.
6) Frequent shutdowns contribute to infiltration of dissolved oxygen and other non-condensable gases, which increase the levels of erosion and corrosion.
7) Fatigue stresses during start-up and shutdown result in cracking of electrical equipment and the resulting arcing and burning cause short-circuits (Fig. 2.10).

Fig. 2.10. Cracked copper turn and rotor bowing [13].

2.1.3. Costs of Cycling Operation: Start-up Costs

The factors that contribute to the total costs of cycling are the following [13]: (1) increased fuel consumption due to increased plant start-ups and operation at part-load levels (efficiency decrease); (2) increased fuel consumption due to loss of plant efficiency arising from increased wear to components; (3) increased operation and maintenance (O&M) costs due to increased wear-and-tear of plant components; (4) increased capital costs resulting from component failures; (5) increased environmental costs resulting from increased emissions; and (6) loss of income due to longer and more frequent forced outages.

The less stable the operating conditions, the greater the increased costs. Costs and effects on maintenance are estimated to be higher for coal-fired plants than for gas-fired plants, which are more technically suited to ramping up and down and operation at part load [19].

According to [13], Aptech Ltd. has analysed cycling costs for over 300 generating units and found that the costs of cycling for conventional fossil-fired power plant can range from 2500–500 000 $ (2014–402 808 €) per start/stop cycle depending on unit age, operating history and design features, and are often extremely underestimated by utilities. It is challenging to estimate the costs of cycling operation that is why they are not evaluated to the end.

Significant attention is devoted to start-up costs, when the cycling operation of the thermal power plant is considered in the short term (production planning, operation scheduling, trading at spot and forward market) [24]. In this case, start-up costs are calculated taking into account the consumed fuel and produced carbon dioxide emissions [25]:

$$C_{start} = \sum_{t=1}^{n_{start}} \left[\sum_{i=1}^{n_{CHP}} (B_{it} C_{Fuel}^{t} + E_{it}^{CO_2} \Pi_t^{CO_2}) \right], \tag{2.1}$$

where n_{start} – start-up time, h;

B_{it} – fuel consumption of the unit at the time interval t_n, thous. m^3/h;

C_{Fuel}^{it} – fuel cost, €/thous. m^3;

$E_{it}^{CO_2}$ – CO_2 emission volumes at time period t_n, t/h;

$\Pi_t^{CO_2}$ – CO_2 emission allowance cost, €/t.

In turn, in [26], the non-fuel costs (sum of maintenance, repairs, capital expenditure, inspection and wear and tear costs) of start-up process are taken into account. P. Keatley, A. Shibli and N. J. Hewitt created a model, which can be used to forecast lifetime costs of hot, warm and cold start-up for a typical base load. Cost data are examined in relation to two life consumption metrics: creep life (measured in online hours) and fatigue life (measured in starts). Such estimation of start-up costs can be used for assessing both the technical and economic effects of cycling operation and incorporating them into system planning studies. It is appropriate, when the cycling operation of TPPs is considered in the long term.

For instance, in [27], it is stated that the start-up costs of generator are approximately proportional to its capacity. The cold start-up costs for CCGT power plant are around 56 $/MW (48 €/MWh*) and hot start-up costs for CCGT power plant are around 37 $/MW (32 €/MWh*). Coal-fired unit is turned on and off much less often than CCGT power plants in real operation, and most of start-up is cold start-up. The costs are 81–129 $/MW (70–129 €/MWh*).

The start-up costs can vary from a maximum cold start-up value to a much smaller value if the unit has only been turned off recently and it is still relatively close to operating temperature. There are two approaches to treating a thermal unit during its shutdown period. The first (called cooling) means the cooling down of unit and then its heating back up to operating temperature in time for a scheduled turn on. The second (called banking) means that the operation temperature of unit is maintained [20], [28] (Fig. 2.11).

$$Strat-up\ \cos ts_{(cooling)} = C_c \left(1-\varepsilon^{-t/\alpha}\right) \times F + C_f, \tag{2.2}$$

where C_c – cold start-up costs, MBtu;

F – fuel costs; €

C_f – fixed costs, €;

α – thermal time constant for the unit;

t – time when the unit was cooled, h.

$$Strat-up\ \cos ts_{(banking)} = C_t \times t \times F + C_f, \tag{2.3}$$

* 1 $ = 0.8644 € at 05 August 2018

where C_t – costs of maintaining unit at operating temperature, MBtu/h;

F – fuel costs; €

C_f – fixed costs, €;

t – time when the unit was cooled, h.

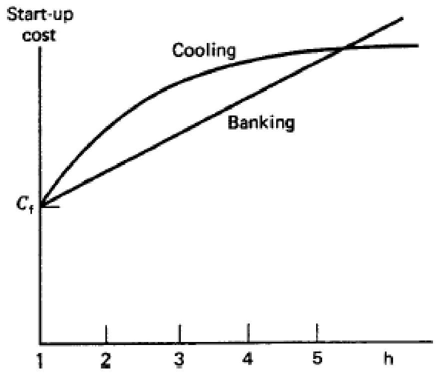


Fig. 2.11. Time dependent start-up costs [20].

Up to a certain number of hours, the banking costs will be less than the cooling costs (Fig. 2.11).

2.2. Definition and Parameters of Generation Flexibility

Flexibility describes the extent to which an electricity system can adapt the pattern of electricity generation and consumption in order to balance supply and demand. Electricity system flexibility has four sources: generation, electricity storage, interconnection with other electrical systems and demand response. Traditionally, generation flexibility is the dominant source of system flexibility. Generation flexibility is examined in this Thesis [19]. It refers to the extent, to which generators across a given system can respond to the variability in the residual load on a timescale of a few minutes to several hours. The main parameters of generation flexibility are summarised in Fig. 2.12. [15], [19].

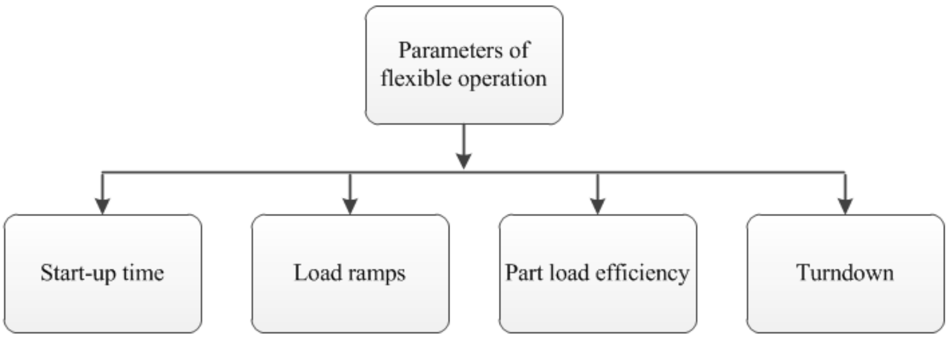


Fig. 2.12. The main parameters of flexible operation (developed by the author according to [19], [29]).

Start-up time denotes the period before the plant achieves stable combustion conditions. Ramping capability characterises power plant ability to respond to changes in demand by ramping up to provide demand during high net loads or by ramping down to ensure grid stability when loads decrease [15], [19]. Part-load efficiency defines improvements, which are able to reduce the short-run marginal costs for electricity generation [19]. Turndown ratio denotes the minimum stable operation load and is expressed as a percentage of full load. The examples of power plant comparison by flexible performance parameters are provided in Section 2.4.

2.3. Fast Start-up: New Economic Benefits

Fast start-up is an essential feature to ensure economic success under variable operation conditions. Fast start-up ensures the following (Fig. 2.13) [30]:

1. **Reduction of start-up costs.** Fast start-up reduces the time of unit operation in unfavourable loads at low efficiency. Thus, the overall efficiency increases during start-up: less fuel is consumed, fewer emissions are produced and the output of electricity is increased. As a result, the start-up costs are reduced.
2. **additional earnings through participation in ancillary markets**. Ancillary services are necessary to guarantee grid stability and comprise frequency response, reactive power compensation, spinning reserve and hour reserve. A fast start-up plant can provide these services. The earnings of these services are normally divided into the payment for the capability to provide power (availability fee) and the payment for energy generated kilowatt hour (utilization fee), which is normally significantly higher than the intermediate or peak load market price. Power plant owners can optimise their load profile participating in ancillary service markets and power markets. This leads to an increased profitability of the power plant.

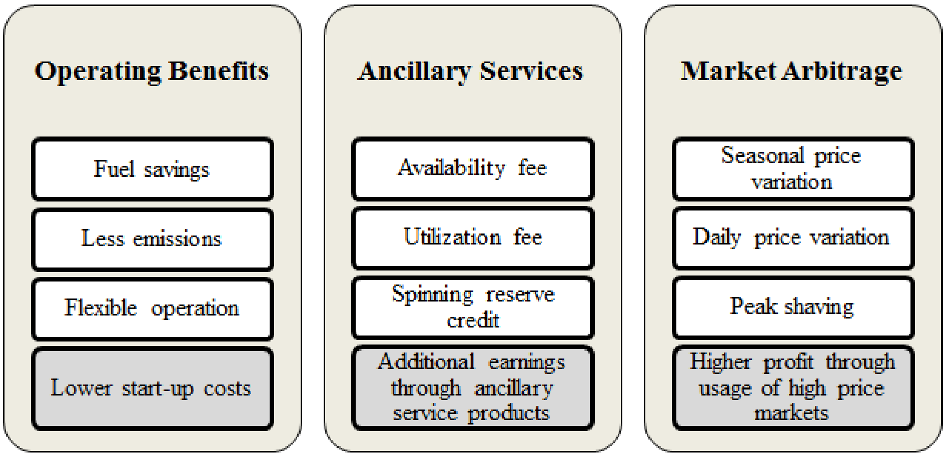


Fig. 2.13. Benefits from fast start-up capability (developed by the author according to [30], [31]).

3. **Increased revenue through usage of market arbitrage.** The future development of electricity prices is a major issue in the liberalized market. The fact is known that the

electricity price will change. A flexible plant can be shut down if electricity prices are below variable costs and it can be online if prices exceed variable costs. These plants benefit from high prices but do not have to operate with a deficit when electricity prices are low. The changes of electricity can be derived using historical data from the energy exchanges and statistical methods. Supplementing the economic model of the power plant with the information about electricity price fluctuations leads to a more accurate picture of profitability of the power plant operation under electricity market conditions.

2.4. Comparison of Thermal Power Plants by Flexible Performance Parameters

The comparison of power plants flexibility levels is made in this section. The information provided below is based on [19]. The efficiency of TPP decreases, when the load of unit decreases. As a result, the fuel consumption and the production of carbon dioxide (CO_2) emissions increase. CCGT technology has the best efficiency compared with open combined gas turbine (OCGT) technology, internal combustion engine (ICE) and supercritical pulverized coal (SCPC) plant, when the load of unit is more than 60 % of the installed capacity. The efficiency of CCGT, OCGT, ICE rapidly decreases, when the load is below 60 % of the installed capacity (Fig. 2.14). Thus, the negative effect of the operation at reduced load is typical of OCGT, CCGT and IEC at a 30 % load. The efficiency of SCPC technology insignificantly changes along with a decrease in its load. That is why the part-load efficiency penalty is less pronounced than in case of CCGT, OCGT and ICE (Fig. 2.15).

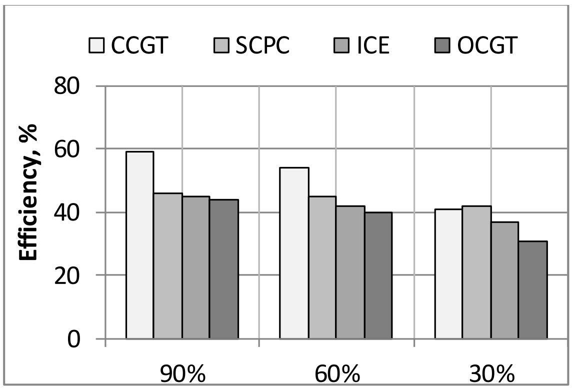


Fig. 2.14. Efficiency versus load for different technologies (developed by the author according to [19]) (OCGT approx. 100 MW; CCGT – 120 MW; ICE – 20 MW; SCPC – 1 GW).

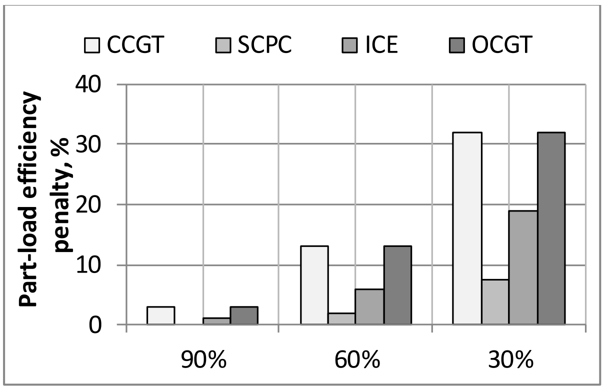


Fig. 2.15. Part-load efficiency penalty for different technologies (developed by the author according to [19]) (OCGT approx. 100 MW; CCGT – 120 MW; ICE – 20 MW; SCPC – 1 GW).

The fastest start-up time is demonstrated by OCGT technology, followed by flexible and conventional CCGT technologies. The flexible CCGT power plants have two times shorter start-up time than conventional CCGT power plants. Brown coal thermal power plants have the longest duration of start-up, i.e., 150 minutes (Fig. 2.16).

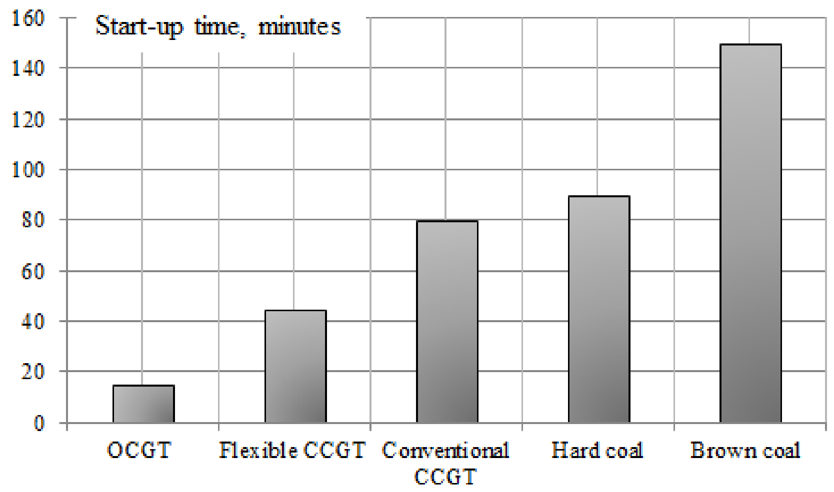


Fig. 2.16. The duration of hot start-up time of different technologies (developed by the author according to [19]).

The start-up trajectories of OCGT, flexible and conventional CCGT, hard and brown coal thermal power plants are reflected in Fig. 2.17.

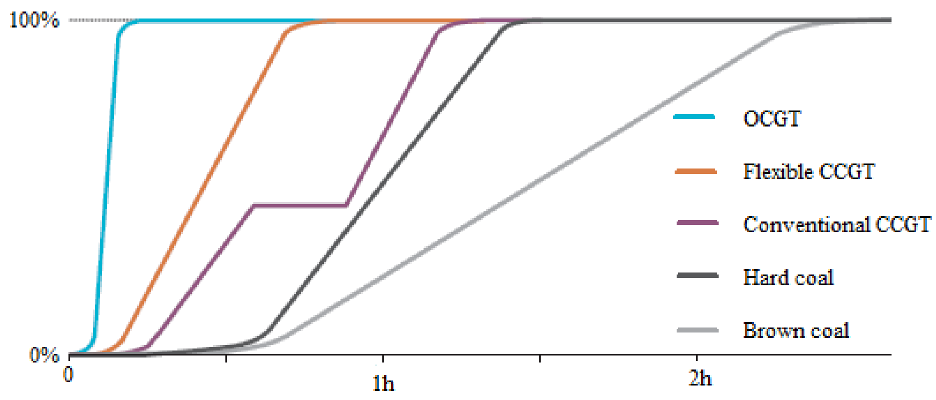


Fig. 2.17. The start-up trajectories of different technologies [19].

The fastest ramp rate up to 25 % of full load (FL) is demonstrated by ICE and OCGT technologies, which are followed by CCGT technology. The ramp rate of OCGT technology varies widely. It ranges from 8 % to 25 % of the installed capacity per minute. Coal power plants have the slowest ramping capability. Its range of change is also small, i.e., 2 %–5 % of the installed capacity per minute. This is the reason for the long start-up of coal power plants (Fig. 2.17 and Fig. 2.18).

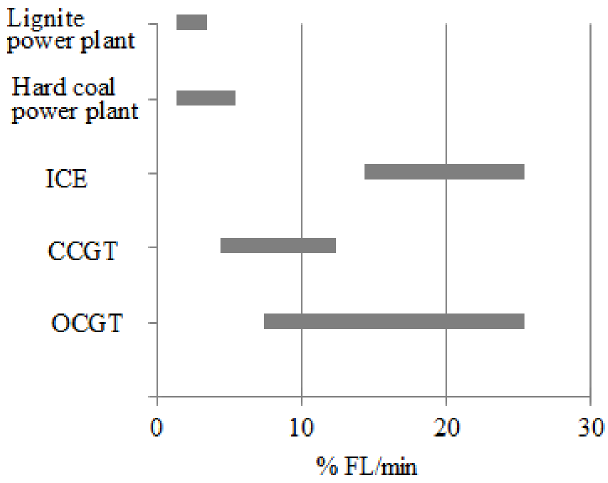


Fig. 2.18. The ramping capability of different technologies (developed by the author according to [19]); (Installed capacity of power plants: lignite: 500–1000 MW; CCGT: 300–500 MW; OCGT: 20–200 MW; ICE: 20–200 MW).

The lowest turndown (10 % of the installed capacity) is demonstrated by ICE technology, followed by OCGT and hard coal power plant. CCGT technology has a short start-up time and rapid ramp rate, but this technology can reduce load only by 30 % of the installed capacity (Fig. 2.19).

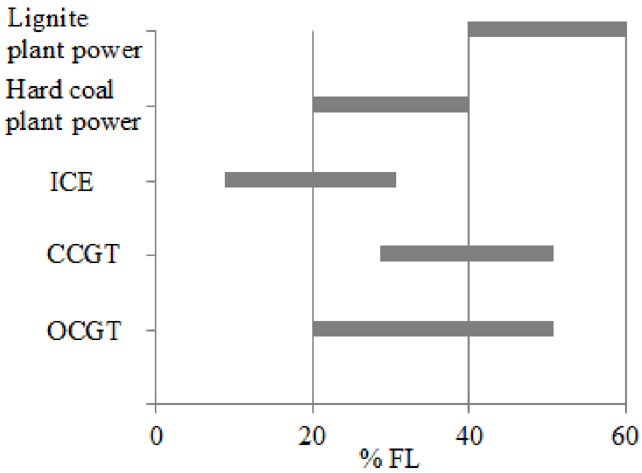


Fig. 2.19. The minimum turndown of different technologies (developed by the author according to [19]); (Installed capacity of power plants: lignite: 500–1000 MW; CCGT: 300–500 MW; OCGT: 20–200 MW; ICE: 20–200 MW).

2.5. Flexibility Improvement Measures

The measures to increase the flexibility level of fossil fuel power plants can be divided into two groups (Fig. 2.20) [11]:

I. Measures available at the operation stage of the constructed thermal power plants;

II. Measures applicable at the design stage of new thermal power plants.

The first group includes two subtypes – related to the necessity of reconstruction of power plants or linked with more complicated usage of their existing equipment features.

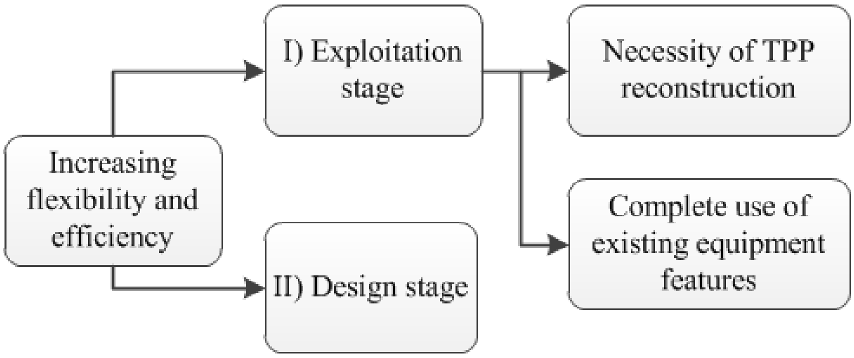


Fig. 2.20. Increasing the efficiency and flexibility level according to the stage of power plants (exploitation stage → operation stage) [11].

Further the measures of the first group are overviewed in detail. The information about the measures of the second group is provided in [11].

There are a large number of publications and scientific studies about improvement of the flexibility and efficiency of TPPs at the operation stage by ensuring the reconstruction of power plants or by ensuring more complete use of existing features. More than 30 literature sources have been studied and analysed. As a result, all the possibilities to ensure flexible and profitable operation of TPPs have been divided into five groups (Fig. 2.21).

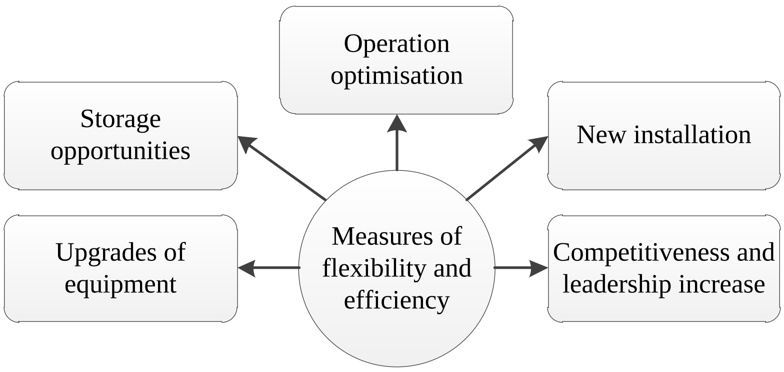


Fig. 2.21. Groups of measures for providing flexible and profitable operation of thermal power plants [11].

The groups in Fig. 2.21 are presented in descending order – from the most used to the less used ones. They differ by the degree of complexity, investment, time of implementation, sources used, etc., but are united by one goal – to enhance the efficiency and flexibility of power plants.

2.5.1. Upgrades of Equipment

These are the different types of measures, which are developed and offered by manufacturers. Mainly these are upgrades for gas turbines, steam turbines and heat recovery steam generators because the cycling operation has crucial impact [13], [15], [26] on technical resources of the equipment [11].

Upgrades listed in [30]–[32] anticipate: the preservation of warm state during shutdown; the maintenance of HRSG availability; optimisation of power plant equipment design; optimisation of automatisation. The implementation of these measures ensures reliable and fast start-up of thermal power plants by installing additional components or providing the modernisation of the existing equipment.

There are many optimisation options for gas turbine (*OpFlex Solutions*), which are presented in [33]–[37]. These solutions contain four packages, which (1) target and enhance various components of the start-up process; (2) extend output capacity and control operational availability and emissions footprint; (3) provide operation with confidence in a dynamic market environment; (4) ensure operation of minimum loads using less fuel and producing lower emissions. The programming work is necessary to penetrate *OpFlex Solutions* in use.

In addition, the group *"Upgrades of Equipment"* presumes the production of equipment from the high strength P91 steel, the so-called next generation power plant equipment. This will allow making high-pressure components thinner. As a result, these components will reach thermal equilibrium quicker and therefore will be less susceptible to cracking [13], [26].

2.5.2. Storage Opportunities

There are different types of storage technologies: (1) hydropower accumulation, (2) electricity accumulation, (3) heat accumulation, etc. There are different techniques to provide heat accumulation: heat energy accumulation in heat storage tanks and heat energy storage in pipes of the district heating system [11].

Nowadays the heat storage system is widely used to increase the efficiency and flexibility of power plant operation because the heat storage system decouples heat and electricity production [13], [38], [39] and allows producing more electricity to the power market, when the electricity prices are high. In addition, power generation is reduced, when prices are low.

There are different destinations of heat storage tank use regarding operation modes of thermal power plant [40]. If power plant operates in the condensing mode during the daytime (a high electricity price on the market), the heat storage tank is discharged during the daytime. The charging process of heat storage tank occurs at night (a low electricity price on the market) [15], [38], [41]–[44]. If TPP operates in the cogeneration mode during the day, the heat storage system is charged during the daytime. The discharge of heat storage tank is provided at night, when a thermal power plant is out of operation [38], [39]. This manner of operation is not common as the previous one. The modelling approach is used to optimise the operation of heat storage tank and thermal power plant. For instance, in [39] a linear programming model is developed, consisting of hourly models, which are connected together with dynamics storage constraints. The aim of objective function is to minimise the production costs of a power plant. The choice of accumulation system operation has become a challenging decision due to future uncertainties.

Heat energy accumulation in district heating system pipes is used to obtain the additional electricity power during the peaks of electricity load. It is proposed that the use of heat accumulation in pipes can displace the heat load from peak energy sources and reduce the fuel consumption by 1.5–2 times. Moreover, it is cheaper to use accumulation in pipes than the thermal energy storage system. The heat accumulation in pipes is not common in the non-heating period because during this period the peaks of energy demand are not so pronounced as in the heating period. The heat accumulation in pipes is also used to level the heat load. Moreover, it can be used to reduce the operation of peak load equipment, and in this way the service life of the equipment can be increased [45], [46].

2.5.3. Optimisation of Thermal Power Plant Operation

The operation of TPPs in liberalized markets depends both on uncertain electricity prices and on uncertain heat demand [47]. The most profitable operation of a power plant can be achieved by planning its operation using an optimisation model [39]. The modelling of unit commitment (UC) and unit dispatch are the most common approaches, which provide the short-term optimisation of thermal power plant. The planning of TPP operation can reduce fuel consumption and environmental waste up to 3 %–10 % or increase thermal power plant efficiency to 1.2 %–4.4 % [48]. For example, the optimisation of load distribution in TPPs allows reducing the fuel costs by approximately 1 %–5 % [49].

There are a lot of literature sources that propose optimisation models of power plants. For instance, the stochastic unit commitment model for a local TPP is introduced [49], which takes into account a varying spot price as uncertainty criteria. In [50], the formulation of mixed-integer linear programming optimisation problem is given, whose aim is to obtain the optimal operation schedule of every component of a power plant. In [25], the economic dispatch and unit commitment models of the combined cycle gas turbine power plant under electricity market conditions are presented taking into account new environmental challenges. To create a model, the characteristics of a power plant are used because they affect the operation of a power plant [27]. For example, the power output of combined cycle gas turbine power plants is strongly affected by ambient environment. The results obtained in [27] show that high temperature, low barometric pressure and heavy air pollution have a remarkable impact on the system operation.

2.5.4. New Installations

Additional installations (such as an electric boiler, heat exchange, bypasses stack, gas turbine storage technology, gas turbine integrated storage, etc.) in the thermal power plant scheme adjust operation modes of TPPs to new running conditions.

The use of an electric boiler increases the flexibility of thermal power plants by providing the heat energy, when the electricity prices are low and it is not profitable to operate a cogeneration unit [12], [51]. This way it is possible to reduce the consumption of primary energy recourses and reduce energy production costs. Additionally, it is possible to use the combination of an electric boiler and heat storage tank [12], [52]. If electricity price and heat energy demand are low, the additionally produced heat by electric boiler can be accumulated in a heat storage tank and used later. The obtained results of the conducted research [51] reflect that a heat storage tank and an electric boiler can reconcile the conflict between the inflexible operation of TPPs and the fluctuation of electricity prices or the use of renewable energy resources.

The installation of an additional heat exchanger ensures the optimisation of start-up process of a power plant. Before the start-up of a thermal power plant, it should be warmed up (for approximately 2 hours). During this process, some of the heat amount is drained into condenser, but it can be used to produce heat energy to the district heating system. In this case, it is necessary to install additional heat exchange with a bypass steam pipeline [15].

The installation of a bypass stack provides the opportunity to operate a combined cycle gas turbine power plant in the open-cycle mode. It means that exhaust heat from a gas turbine is directly ejected into the atmosphere via a bypass stack. The running conditions in the open-cycle mode reduce power output and efficiency of a power plant, but provide operational flexibility: short start-up time (15 to 30 minutes) and quick load change. Mainly combined cycle gas turbine power plants are not equipped with a bypass stack, because a bypass stack leads to leakage losses, which reduce the efficiency of a plant and contribute to additional capital costs. The damper can be used to reduce leakage losses [13], [30], [32].

2.5.5. Competitiveness and Leadership Increase

The increase in competitiveness and leadership has a positive effect on the generation process of a power plant. To hold the leadership position, the production process should be constantly modernised and optimised. For instance, the main reason of district heating (DH) market opening is to increase competition among heat energy supplies [53], [54], [55].

Two steps should be implemented to open a DH market. First, it is necessary to define the conditions of opening of a district heating market, where companies can buy and sell heat. Second, the cooperation profile should be established – the merging of potential market participants into one system [53], [56]. For example, in [56] the MODEST *(model for optimisation of dynamic energy systems with time-dependent components and boundary conditions)* evaluation tool is used to model the situation of district heating market opening in Sweden.

The developed tool can be used to model municipal, regional and national energy systems. In [55], district heating market opening is investigated in Espoo (Finland). The hourly model of Espoo district heating system was established in MatLAB. The main aim of the model is to reduce the heat energy price. The calculation approaches differ according to the heat energy source. In case of heating boiler houses, the calculation of marginal costs depends on fuel price and boiler house efficiency. In case of a cogeneration power plant, the calculation is complex because the function of costs includes fuel costs of electricity and heat production, which are produced with relation of power to heat load (P/Q). The heat energy price, costs of connection, technical constraints and other factors should be taken into consideration to evaluate the influence of district heating market opening on heat energy market participants. Moreover, separate scenarios and some aspects should be evaluated in detail [56]. The future operation of the district heating system depends on fuel prices, CO_2 price levels and electricity market prices [55].

2.6. Shifting to Cycling Operation: A Case of Riga TPP-2

Riga TPP-2 power plant is located in Acone, i.e., 28 km from Riga (the capital of Latvia). It is a base load power plant. Riga TPP-2 consists of two combined cycle gas turbine units (cogeneration units), CCGT-2/1 unit (P = 413 MW and Q = 274 MW) and CCGT-2/2 unit (P = 419 MW and Q = 270 MW), and five heat only boilers (HOBs) (Q = 5 × 116 MW). Natural gas is used as a primary fuel and diesel as an emergency fuel (Fig. 2.22).

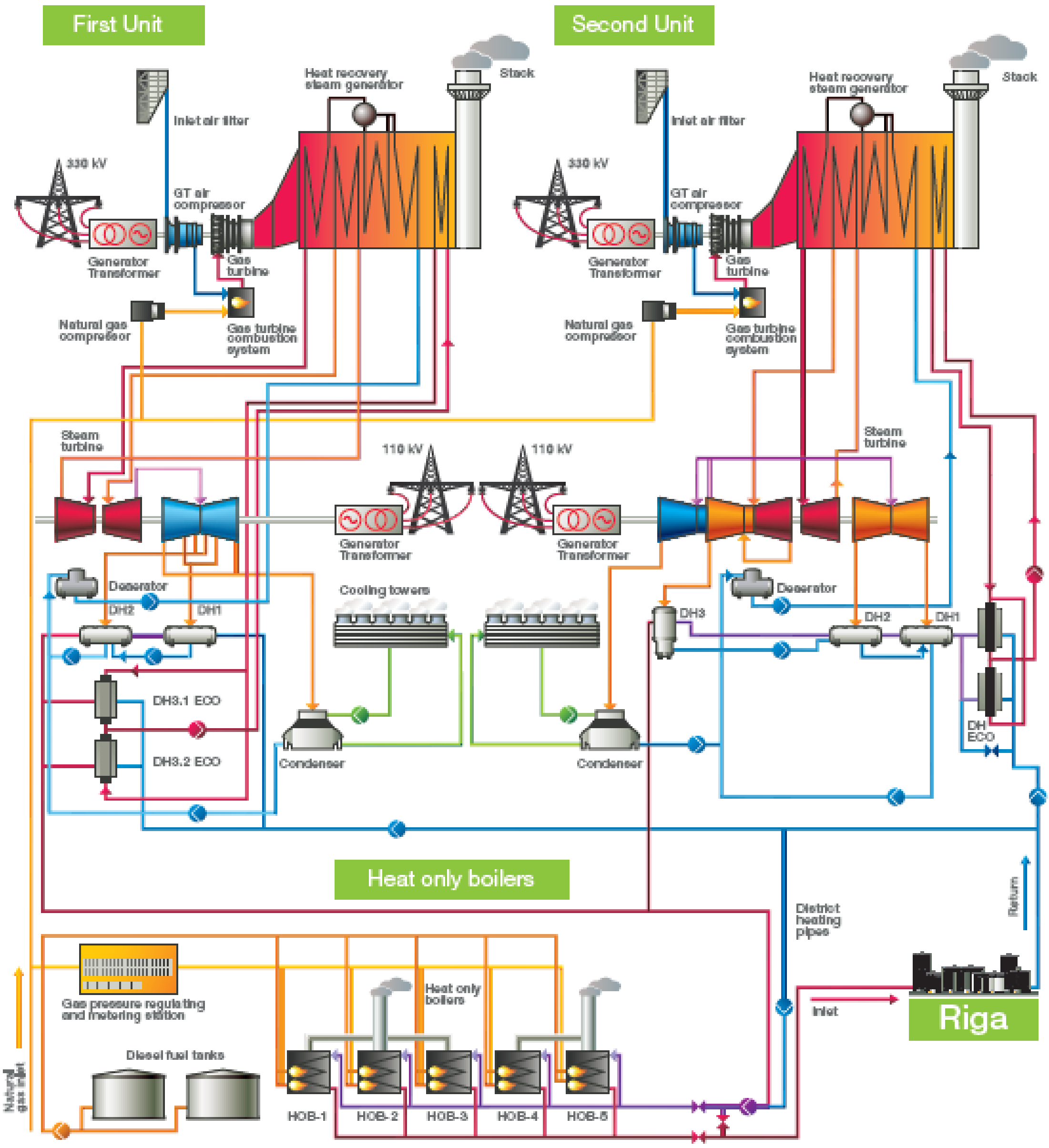


Fig. 2.22. Illustration of Riga TPP-2 [57].

The cogeneration units operate in these three modes:

1) cogeneration and condensation (or mixed mode) ($P_{cog.\&cond.}$ = 190–413 MW and $Q_{cog.\&cond.}$ = 60–180 MW);
2) pure cogeneration ($P_{pure\ cog.}$ = 190–413 and $Q_{pure\ cog.}$ = 180–274 MW);
3) pure condensation ($P_{pure\ cond.}$ = 190–442 MW and $Q_{pure\ cond.}$ = 0 MW).

The running conditions of cogeneration units are determined by ambient air temperature, electricity price and natural gas price. They are identical; therefore, statistics of the overall operation for a period of three years (2014–2016) is shown on the example of CCGT–2/1 unit (Fig. 2.23). The shifting from efficient modes (pure cogeneration) to inefficient operation, i.e., mixed mode can be noticed. For example, the operation in the pure cogeneration mode was 44.09 % in 2014, 1.14 % in 2015 and 16.88% in 2016. In turn, the operation in the mixed mode increased from 31.7 % (in 2014) to 48.37 % (in 2016). The cogeneration unit operated mainly in the pure condensation mode (84 %) in 2015 due to low heat energy demand, low natural gas price and high electricity price. However, the operation in the pure condensation mode was 24.22 % and 34.74 % in 2014 and 2016, respectively.

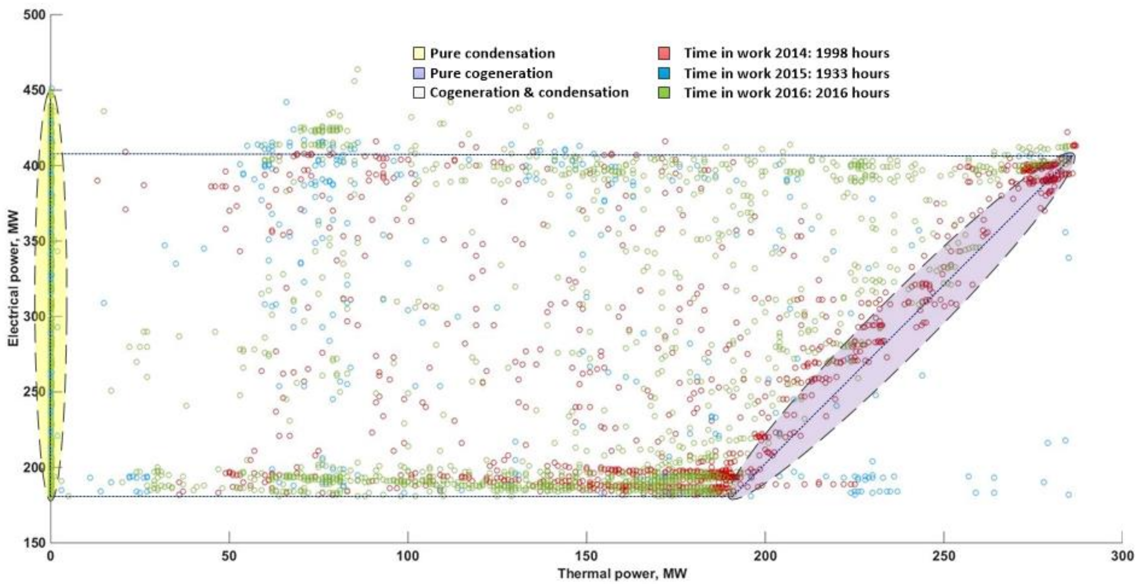


Fig. 2.23. Statistics of CCGT–2/1 unit operation [58].

As mentioned in Section 2.1, Riga TPP–2 started to operate in line with electricity market conditions after Latvia had joined the Nord Pool electricity market. In general, the power plant operates if its electricity production costs (marginal costs) are less than the electricity price on the market and it stops if its marginal costs are higher than the electricity price. This makes changes in the operation of the power plant. The following changes are evident analysing the production data of Riga TPP–2:

1) HOBs are in operation during the periods of low electricity price and high marginal costs of a cogeneration units (mainly at night) (Fig. 2.24).

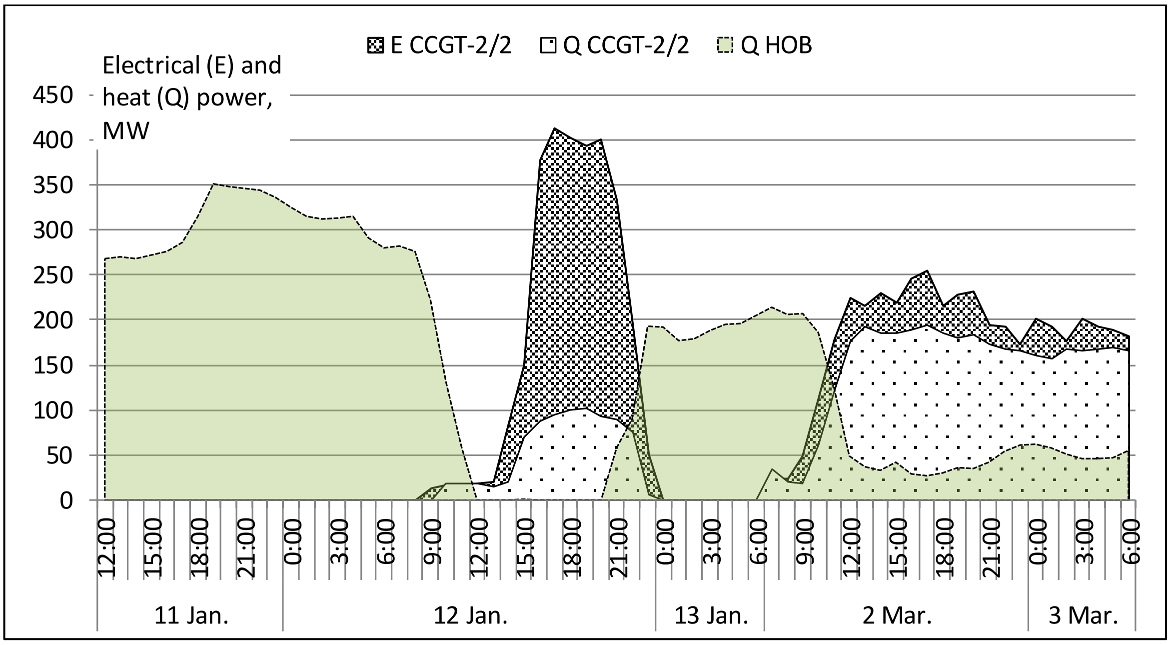


Fig. 2.24. The example of CCGT–2/2 unit operation in January and March 2015 [59].

2) Increase in the number of start-ups is dynamic (Fig. 2.25).

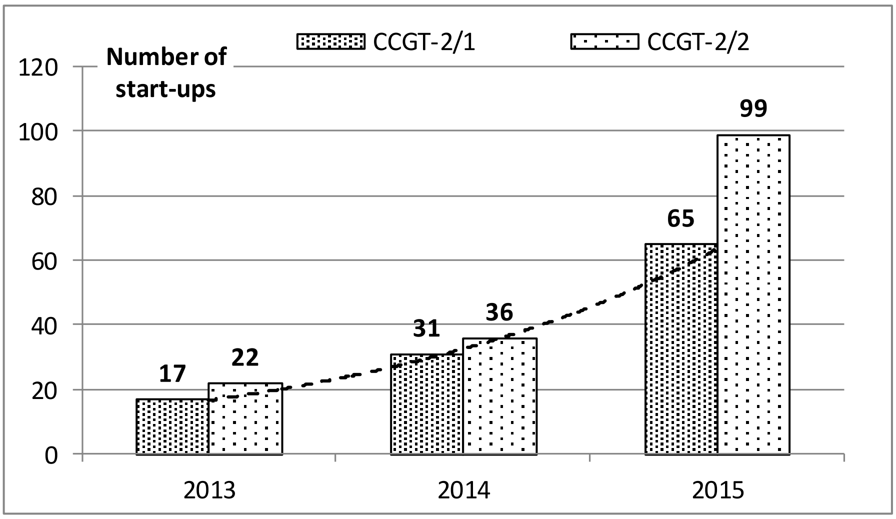


Fig. 2.25. The number of start-ups of CCGT–2/1 unit and CCGT–2/2 unit in 2013, 2014, 2015 [24].

3) With the increase in the number of start-ups the Riga TPP–2 increasingly operates in the insufficient modes. It was concluded in [4] and [24] that start-ups of Riga TPP–2 plant were too long and a lot of fuel was used during start-ups, especially it concerned cold start-ups. This was achieved after comparing Riga TPP–2 production data with benchmark to 9 FA class machines of some European Union utilities provided by *P.-J. Stockmans* and *O. Demaude* in [60].
4) The increase in greenhouse emissions during the gas turbine start-up process and GT operation at load is below 70 %. For example, the increase of NO_x emissions above the limit happens during the cogeneration unit warm-up (gas turbine operation at minimum

load, i.e. 30–40 MW) (Fig. 2.26). In turn, CO emissions significantly exceed the limit during gas turbine acceleration – before the loading of a cogeneration unit (Fig. 2.27).

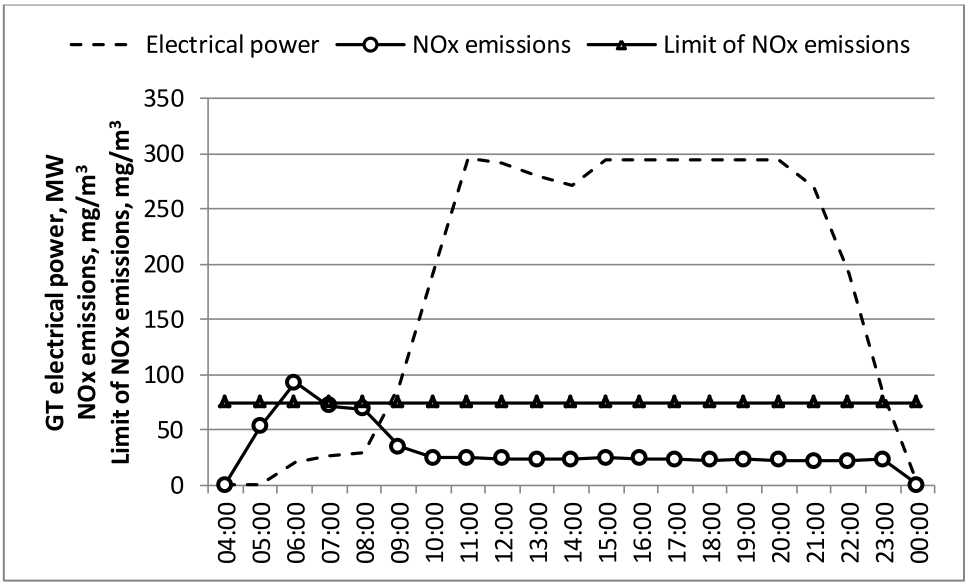


Fig. 2.26. NO_x emissions during the start-up procedure [24].

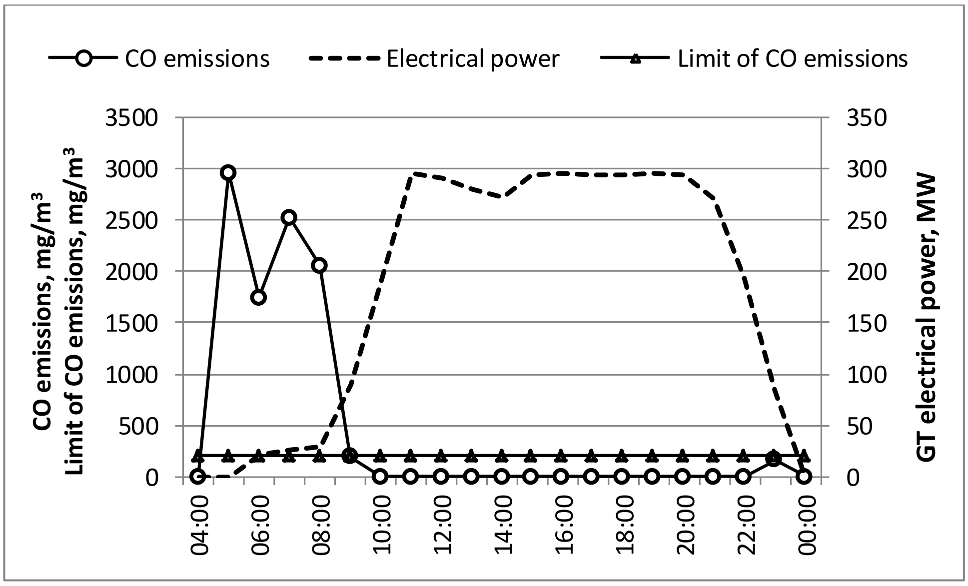


Fig. 2.27. CO emissions during the start-up procedure [24].

The listed changes in operation due to cycling operation on the example of Riga TPP–2 are undesirable for owners of power plants because their goal in the electricity market is to maximise profit, which is determined as the difference between the revenue and the total operating costs. The latter consists of variable and fixed production costs, shutdown and start-up costs (Eq. 2.4) [24], [61].

$$\sum_{t \in T} \{\lambda(t) p^{avg}(t) - [d(p^{avg}(t)) + Cz(t) + By(t)]\} \to max\, P_f\ , \quad (2.4)$$

where $\lambda(t)$ – forecast price of electricity within period t, €/MWh;

$p^{avg}(t)$ – average power output within period t, MWh;

$d(p^{avg}(t))$ – production costs within period t, €/h, which is a nonlinear function of the average power output within period t, $p^{avg}(t)$;

C – shutdown costs, €;

$z(t)$ – 0/1 variable that is equal to 1 if the unit is shut down at the beginning of period t;

B – start-up costs, €;

$y(t)$ – 0/1 variable, which is equal to 1 if the unit starts up at the beginning of period t;

P_f – profit of a power plant, €.

Riga TPP–2 is not fully adapted to the cycling modes [24]. Moreover, taking into account the significance of Riga TPP–2 in the Baltic States, the negative consequences, which are described in detail (with calculus) in [62], may arise, if the flexibility and efficiency of a cogeneration power plant are not sustained:

1) primary energy savings (PES) could reduce from high efficiency cogeneration in Riga district heating system (DHS);
2) greenhouse gas (GHG) emissions could increase in the Baltic region;
3) security of electricity supply could worsen in the Latvian power system;
4) the electricity market price could increase in the Lithuanian and Latvian price areas of the Nord Pool power exchange.

To increase the flexibility level of a thermal power plant, the modernisation of gas turbine was carried out. Gas turbine of CCGT–2/2 unit was equipped with *OpFlex Turndown* in 2014. The benefits of this modernisation are the following: (1) the prevention of a cogeneration unit from daily start-ups (the number of allowed start-ups is limited and it is a function of operating hours); (2) the deep unloading of a unit at night, when electricity price is low. For more details about *OpFlex Turndown* see [4], [15]. The changes of logic in the distributed control system were also made at CCGT–2/2 unit to accelerate the start-up of a steam turbine (to make attemperator flow faster) [4].

The implemented measures are not sufficient; therefore, the developed mathematical models of CCGT power plant transient modes (Chapter 3), the approach to cycling operation optimisation (Chapter 4) and the algorithm for technical and economic justification of technologies (Chapter 5) and its adjustment to certain technologies (Chapters 6, 7, 8) are approbated on the example of Riga TPP–2. It is supposed that the obtained results can show the way how to further improve the flexibility of Riga TPP–2 plant.

2.7. Summary

1. The reasons, aims and benefits of cycling operation vary according to the geographical location of a region, its economic development and the situation in the energy system. The main reasons are fluctuations in the electricity price or intermitted generation variability. In turn, the aims are the adjustment to the situation in the electricity market or the integration of intermittent generation in the energy production process. The benefits are

the additional income from additionally produced electricity and the secure integration of intermittent generation in the energy production process.

2. The types of cycling operation modes (with full shutdown and further hot, warm or cold start-up or load reduction) determine their operation costs and the level of adverse influence on technical resources of equipment. The running conditions with full shutdown and further cold start-up are the most expensive and adverse. The cycling operation with fractional load reduction is the cheapest and the most sparing one.
3. There are two types of cycling costs: fuel and non-fuel. The fuel costs are relevant, when the cycling operation of a TPP is considered in the short term, for example, production planning and operation scheduling. In turn, non-fuel costs – in the long term, for instance, maintenance planning.
4. The main parameters of flexible operation: start-up time, load ramps and reserve capacity, part-load efficiency and turn-down. Fast start-up is an essential feature to ensure economic success under variable operation conditions: lower start-up costs, additional earnings through ancillary service production, increased revenue through the usage of market arbitrage.
5. The coal power plants are less flexible than natural gas power plants. Long duration of start-up, small range of power change and light turn-down refer to coal power plants. Among natural gas power plants, OCGT technology has the fastest start-up time and ICE technology has the lowest turn-down. In turn, ICE and OCGT technologies have the fastest ramp rate. The flexibility level of CCGT technology is in between IEC and OCGT technologies as well as coal power plants.
6. The flexibility level of TPP can be increased at the design stage or the operation stage. The measures available at the operation stage of the constructed power plant are divided into five groups: upgrades of equipment, storage opportunities, operation optimisation, new installation, increase in competitiveness and leadership. They differ by the degree of complexity, investment, time of implementation, sources used, etc., but are united by one goal – to enhance the efficiency and flexibility of fossil fuel thermal power plants.

3 MATHEMATICAL DESCRIPTION OF TRANSIENT MODES OF CCGT POWER PLANT

3.1. Mathematical Model

Table 3.1 presents the nomenclature used in the methodology to provide the mathematical description of transient modes.

Table 3.1

The Nomenclature Used in Methodology [63]

Sign	Explanation	Sign	Explanation
P_e	Electrical power/electrical energy	*SUIV*	The fourth stage of start-up
P_{eTHmin}	Electrical power at technical minimum	n	Denotes the duration of outage and type of start-up time (if 0 h < $n \leq 12$ h => hot start-up, if 12 h < $n \leq 72$ h => warm start-up; if $n > 72$ h => cold start-up)
Q	Heat power/heat energy	i	The start of the shutdown process
t	Time (duration)	$i + z$	The end of the shutdown process
GT	Gas turbine	k	The start of *SUI*
ST	Steam turbine	$k + b$	The end of *SUI*
B	Fuel (natural gas)	k'	The start of *SUII*
SD	Shutdown	$k' + c$	The end of *SUII*
WSP	Warm state preservation	k''	The start-up of *SUIII*
TRM	Transient modes	$k'' + d$	The end of *SUIII*
SUI	The first stage of start-up	k'''	The beginning of *SUIV*
SUII	The second stage of start-up	$k''' + e$	The end of *SUIV*
SUIII	The third stage of start-up	$B_{WSP}^{t;n}$	Fuel consumption taking into account the duration of outage *"t"* and start-up time *"n"*.

Transient modes of CCGT power plants are complicated and depend on many factors. For the evaluation of transient modes it might be feasible to divide them into three blocks (Fig. 3.1): vertical line bars correspond to shutdown; the area without bars coincides with the preservation of warm state of the unit; the dotted bars correspond to the start-up divided into four sub-blocks (*SUI*, *SUII*, *SUIII*, *SUIV*); the horizontal line bars identify the loading process.

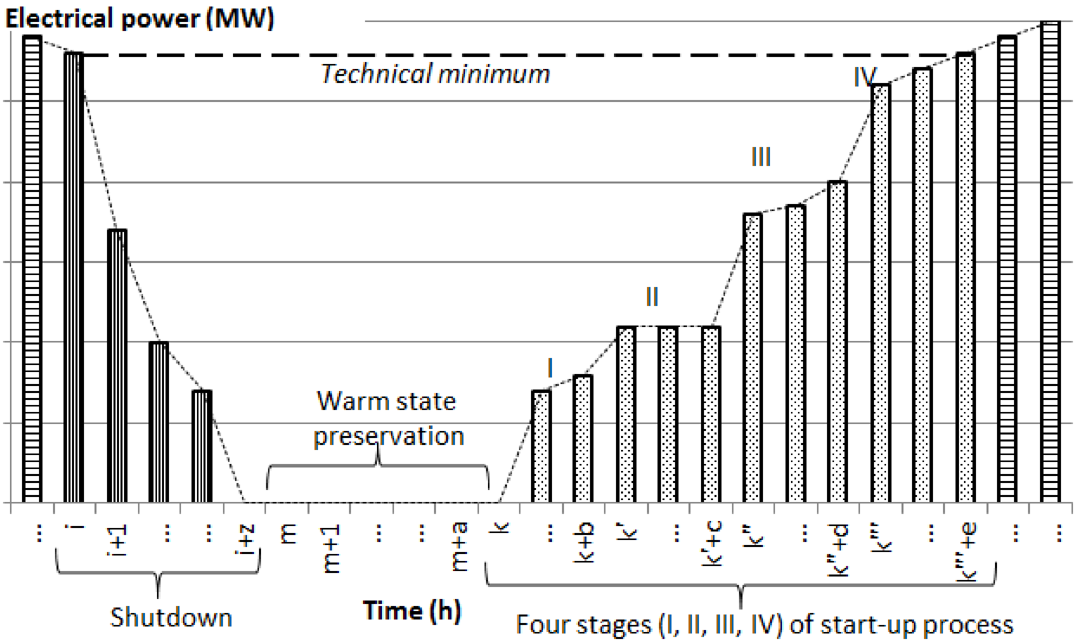


Fig. 3.1. The illustration of transient modes (one cycle) [63].

The shutdown (Table 3.2) is the process of a decrease in the electrical power of a CCGT power plant from $P_{eSD}{}^{t=i+z} \leq P_{eSD} \leq P_{eSD}{}^{t=i}$, where $P_{eSD}{}^{t=i} = P_{eTHmin}$ and $P_{eSD}{}^{t=i+z} = 0$ ($GT_{SD}{}^{t=i+z} \leq GT_{SD} \leq GT_{SD}{}^{t=i}$ and $ST_{SD}{}^{t=i+z} \leq ST_{SD} \leq ST_{SD}{}^{t=i}$). The duration of the process is from i to i+z. The consumed fuel $B_{SD} = f\,(P_{eSD})$ and produced heat $Q_{SD} = f\,(P_{eSD})$. As $P_{SD}\downarrow \Rightarrow B_{SD}\downarrow$ and $Q_{SD}\downarrow$.

Table 3.2

The Description of Shutdown [63]

Parameters	Change in parameters during shutdown
t	$i \ldots i + z$
P_e	$P_{eSD}{}^{t=i+z} \leq P_{eSD} \leq P_{eSD}{}^{t=i}$; $P_{eSD}{}^{t=i}=0$; $P_{eSD}{}^{t=i+z} = P_{eTHmin}$
GT	$GT_{SD}{}^{t=i+z} \leq GT_{SD} \leq GT_{SD}{}^{t=i}$; $GT_{SD}{}^{t=i}=0$;
ST	$ST_{SD}{}^{t=i+z} \leq ST_{SD} \leq ST_{SD}{}^{t=i}$; $ST_{SD}{}^{t=i}=0$;
Q	$Q_{SD}\downarrow=f(P_{SD})\downarrow$
B	$B_{SD}\downarrow=f(P_{SD})\downarrow$

During the preservation of warm state (Table 3.3), the unit is not in operation, which continues from m to $m + a$. The consumed amount of fuel is determined by the type of start-up (n) and the duration of outage (t), i.e., $B_{WSP} = f\,(t_{WSP}; n)$. If outage is too long (mainly corresponds to cold start-up), then $B_{WSP} = 0$.

Table 3.3

The Description of Warm State Preservation [63]

Parameters	**Change in parameters during the preservation of a warm state**
t	$m \ldots m + a$
P_e	$P_{eWSP} = 0$
GT	$GT_{WSP} = 0$
ST	$ST_{WSP} = 0$
Q	$Q_{WSP} = 0$
B	$B_{WSP} = 0$ or $B_{WSP}{}^{t;n} = const$, i.e., if $B_{WSP} > 0$ then $B_{WSP} = f(t_{WSP};n)$

The start-up (Table 3.4) is the process of an increase in the electrical power from $P_e = 0$ *MW* to P_{eTHmin} during the period from k to $k''' + e$. Due to the complexity of the start-up process, it is divided into four stages (*SUI, SUII, SUIII, SUIV*) [63].

Table 3.4

The Description of Start-ups [63]

	SUI: Start-up of GT	*SUII: Warm-up of ST*	*SUIII: Start-up of ST*	*SUIV: Achieving technical minimum*
t	$t = f(n);\ k \ldots k + b$	$t = f(n);\ k' \ldots k'' + c;$	$t = f(n);\ k'' \ldots k'' + d$	$t = f(n);\ k''' \ldots k''' + e$
P_e	$P_{eSUI}{}^{t=k} \leq P_{eSUI} \leq P_{eSUI}{}^{t=k+b}$; $P_{eSUI}{}^{t=k} = 0$	$P_{eSUII}{}^{t=k} \leq P_{eSUII} \leq P_{eSUII}{}^{t=k'+c}$ $P_{eSUII} = const$	$P_{eSUII}{}^{t=k''} \leq P_{eSUIII} \leq P_{eSUIII}{}^{t=k''+d}$	$P_{eSUIV}{}^{t=k'''} \leq P_{eSUIV} \leq P_{eSUIV}{}^{t=k'''+e}$ $P_{eSUIV}{}^{t=k'''+e} = P_{eTHmin}$
GT	$P_{eSUI} = GT_{SUI} \Rightarrow 0 \leq GT_{SUI} \leq P_{eSUI}{}^{t=k+b}$	$P_{eSUII} = GT_{SUII} = const$	$P_{eSUII} = GT_{SUII} = GT_{SUIII} = const$	$GT_{SUIV}{}^{t=k'''} \leq GT_{SUIV} \leq GT_{SUIV}{}^{t=k'''+e}$
ST	$ST_{SUI} = 0$	$ST_{SUII} = 0$	$ST_{SUII}{}^{t=k''} \leq ST_{SUII} \leq ST_{SUII}{}^{t=k''+d}$	$ST_{SUIV}{}^{t=k'''} \leq ST_{SUIV} \leq ST_{SUIV}{}^{t=k'''+e}$
Q	$Q_{SUI}\uparrow = f(P_{eSUI})\uparrow$	$Q_{SUII} = const$	$Q_{SUIII}\uparrow = f(P_{SUIII})\uparrow$	$Q_{SUIIV}\uparrow = f(P_{SUIIV})\uparrow$
B	$B_{SUI}\uparrow = f(P_{eSUI})\uparrow$	$B_{SUII} = const$	$B_{SUIII}\downarrow = f(P_{SUIII})\uparrow$	$B_{SUIV}\uparrow = f(P_{SUIV})\uparrow$

SUI

Only gas turbine is in operation ($0 \leq GT_{SUI} \leq P_{eSUI}{}^{t=k+b}$). The steam turbine is not in operation. The electrical power of thermal power plants is equal to gas turbine output, i.e., $P_{eSUI} = GT_{SUI}$. Heat energy can be produced by district heating economizer (DH ECO) embedded into the heat recovery steam generator. The consumed fuel $B_{SUI} = f(P_{eSUI})$ and produced heat power $Q_{SUI} = f(P_{eSUI})$. As $P_{eSUI}\uparrow \Rightarrow B_{SUI}\uparrow$ and $Q_{SUI}\uparrow$. The duration of *SUI* period is from k to $k + b$ (Table 3.4).

SUII

Only gas turbine is in operation at ~ GT_{SUII}, and $GT_{SUII} = const$. The steam turbine is warmed during this period. The electrical power of thermal power plants is equal to gas turbine output, i.e., $P_{eSUII} = GT_{SUII} = const$. Heat energy is produced by DH ECO. As $P_{eSUII} = GT_{SUII} = const$, then $B_{SUII} = const$ and $Q_{SUII} = const$. The duration of SUII is from k' to $k'' + c$ (Table 3.4).

SUIII

Gas turbine is still in operation at ~ $GT_{SUII} = GT_{SUIII}$, but the electrical power output of the unit increases from $P_{eSUII}{}^{t=k''}$ to $P_{eSUIII}{}^{t=k''+d}$ due to the loading of steam turbine ($ST_{SUII}{}^{t=k''} \leq ST_{SUII} \leq ST_{SUII}{}^{t=k''+d}$). During this process, it is also warmed. Heat energy is produced by district heating economizer (DH ECO). The consumed fuel $B_{SUIII} = f(P_{eSUIII})$ and produced heat $Q_{SUIII} = f(P_{eSUIII})$. *As* P_{eSUIII}

$\uparrow$=> $Q_{SUIII}\uparrow$, but $B_{SUIII}\downarrow$ (Table 3.4).

SUIV Parallel loading of the steam ($ST_{SUIV}{}^{t=k'''} \leq ST_{SUIV} \leq ST_{SUIV}{}^{t=k'''+e}$) and gas turbines ($GT_{SUIV}{}^{t=k'''} \leq GT_{SUIV} \leq GT_{SUIV}{}^{t=k'''+e}$) is taking place. The duration of *SUIV* is from *k'''* to *k''' + e.* In the end, the electrical power output of a unit increases up to P_{eTHmin}. Heat energy is produced by DH ECO and steam turbine. The fuel consumption $B_{SUIV} = f\ (P_{SUIV})$ and heat production $Q_{SUIV} = f\ (P_{SUIV})$. As $P_{SUIV}\uparrow$ => $B_{SUIV}\uparrow$ and $Q_{SUIV}\uparrow$ (Table 3.4).

Mathematical models are proposed further for the calculation of the transient modes. They determine the amount of produced electricity and heat energy, consumed fuel and produced emissions and variable expenses of the transient modes.

The necessary input data are the following: hourly production data of a CCGT power plant (electrical power, heat power, fuel consumption in time), the price of fuel (natural gas) and carbon dioxide, the low heat value and the emission factor of fuel.

The duration of the transient mode (t_{TRM}) is the sum of three components: the duration of shutdown ($\sum_i^{i+z} t_{SD}$), warm state preservation ($\sum_m^{m+a} t_{WSP}$) and start-up ($\sum\sum_x^y t_{SU_v}$) (Eq. 3.1):

$$t_{TRM} = \sum_i^{i+z} t_{SD} + \sum_m^{m+a} t_{WSP} + \sum\sum_x^y t_{SU_v}, \quad (3.1)$$

where v – denotes the stage of start-up (I, II,III, IV);

x – denotes the beginning of start-up process stages, which are *k; k'; k''; k'''*;

y – denotes the end of start-up process stages, which are *k+b; k'+c; k''+d; k'''+e*.

The produced electricity (P_{eTRM}) during the transient modes is the sum of two elements. They are the produced electricity during the shutdown ($\sum_i^{i+z} P_{eSD}$) and start-up ($\sum\sum_x^y P_{eSU_v}$) (Eq. 3.2):

$$P_{eTRM} = \sum_i^{i+z} P_{eSD} + \sum\sum_x^y P_{eSU_v}. \quad (3.2)$$

The amount of the produced heat energy (Q_{TRM}) is the sum of the produced heat during the shutdown ($\sum_i^{i+z} Q_{SD}$) and start-up ($\sum\sum_x^y Q_{SU_v}$) (Eq. 3.3):

$$Q_{TRM} = \sum_i^{i+z} Q_{SD} + \sum\sum_x^y Q_{SU_v}. \quad (3.3)$$

The consumed fuel (B_{TRM}) is calculated taking into account the consumed fuel during the shutdown ($\sum_i^{i+z} B_{SD}$), warm state preservation ($B_{WSP}^{t;n} \times \sum_m^{m+a} t_{WSP}$) and start-up ($\sum\sum_x^y B_{SU_v}$) (Eq. 3.4):

$$B_{TMR} = \sum_i^{i+z} B_{SD} + B_{WSP}^{t;n} \times \sum_m^{m+a} t_{WSP} + \sum\sum_x^y B_{SU_v}. \quad (3.4)$$

The emitted amount of dioxide emissions (CO_{2TRM}) during the transient modes is equal to the sum of the produced carbon dioxide emissions in *SD*, *WSP* and *SU* (Eq. 3.5):

$$CO_{2\,TMR} = \left(\sum_i^{i+z} B_{SD} + B_{WSP}^{t;n} \times \sum_m^{m+a} t_{WSP} + \sum\sum_x^y B_{SU_v}\right) \times Q_{LHV} \times E_{CO_2}, \quad (3.5)$$

where Q_{LHV} – a low heat value of natural gas, MWh/m^3;

E_{CO_2} – a natural gas emission factor, t/MWh.

The costs of the transient modes (C_{TRM}) are the sum of shutdown, start-up and warm state preservation costs (Eq. 3.6):

$$C_{TMR} = \left(\sum_{i}^{i+z} B_{SD} + B_{WSP}^{t;n} \times \sum_{m}^{m+a} t_{WSP} + \sum\sum_{x}^{y} B_{SU_v}\right) \ldots$$
$$\ldots \times (P_{nat_{gas}} + Q_{LHV} \times E_{CO_2} \times P_{CO_2}), \tag{3.6}$$

where P_{nat_gas} – the price of natural gas, €/thous.m^3;

P_{CO_2} – the price of CO_2, €/t.

3.2. Practical Application of Mathematical Model

The transient modes of CCGT–2/2 unit are calculated. Description of Riga TPP–2 and its units see in Section 2.6.

Fig. 3.2 illustrates the shutdown of CCGT–2/2 unit. The decrease in the electrical power is flat from P_e = 180 MW to P_e = 58 MW (30 % of the unit technical minimum) and steep from P_e = 58 MW to P_e = 0 MW. The fuel consumption, the speed of steam and gas turbine start to decrease, when the electrical power is 30 % of the unit technical minimum.

According to Fig. 3.2, the following is obvious [63]:

1. The duration of shutdown (t_{SD}) is 18 minutes: i = 1 and i + z = 18.
2. The technical minimum (P_{eTHmin}) of CCGT–2/2 unit is 180 MW. In turn, 187 MW > $P_{SD} \geq 0$ MW: 89 MW > $ST \geq 0$ and 98 MW > $GT \geq 0$ MW. The amount of the produced electricity (P_e) is 1830 MWh.
3. The shutdown of a cogeneration unit in Fig. 3.2 follows after its operation in the condensing mode, i.e., Q = 0 MW.
4. The consumed fuel (B_{SD}) is 6460 kg or 9308 m^3 (the density of natural gas: ρ_{nat_gas} = 0.6941 kg/m^3).
5. The produced emission (CO_{2SD}) is 17 t (E_{CO2} = 0.201 t/MWh and Q_{LHV} = 0.00935 MWh/m^3).
6. The costs of shutdown (C_{SD}) are 2044 € (P_{CO2} = 5 €/t and P_{nat_gas} = 0.21048 €/m^3).

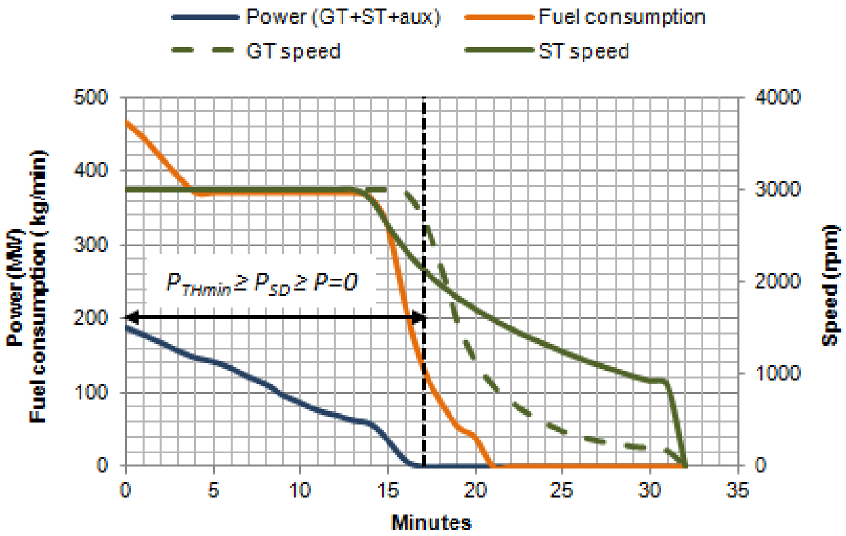


Fig. 3.2. Shutdown of production unit CCGT-2/2 [63].

The developed mathematical model does not take into account the part of shutdown procedure, which is on the right side from the black dashed vertical line (Fig. 3.2). This period is 15 minutes long: power is not produced; the speed of gas turbine and steam turbine decreases and fuel consumption is 181 kg. It is just 2.7 % of the fuel consumption, when $180 \geq P_{SD} \geq 0$. The author considers that this does not influence the calculation accuracy of shutdown costs.

Taking into account the production data of unit CCGT–2/2, it has been evaluated and concluded that it is more expensive to preserve the warm state of the unit before the cold start-up than to do that before the warm and hot start-ups. For instance, in the case of production unit CCGT–2/2 [63]:

- $B_{WSP}^{0 \leq t \leq 12;\ n = hot} \sim 75$ m^3/h;
- $B_{WSP}^{12 < t \leq 72;\ n = warm} \sim 150$ m^3/h;
- $B_{WSP}^{t > 72;\ n = cold} \sim 450$ m^3/h.

If the unit is going to be in outage for a long time, then its warm state is not preserved, i.e., $B_{WSP} = 0$ m^3/h. In this example it is assumed that the warm state is not preserved and the duration of the unit outage (t_{WSP}) is 72 hours (or 4320 minutes): $m = 1$ h and $m+a = 72$ h.

The correct determination of the periods of start-up procedure (*SUI*, *SUII*, *SUIII*, *SUIV*) in line with the proposed methodology requires reflecting the loading process of gas turbine and steam turbine (Fig. 3.3) in addition to the total electrical power.

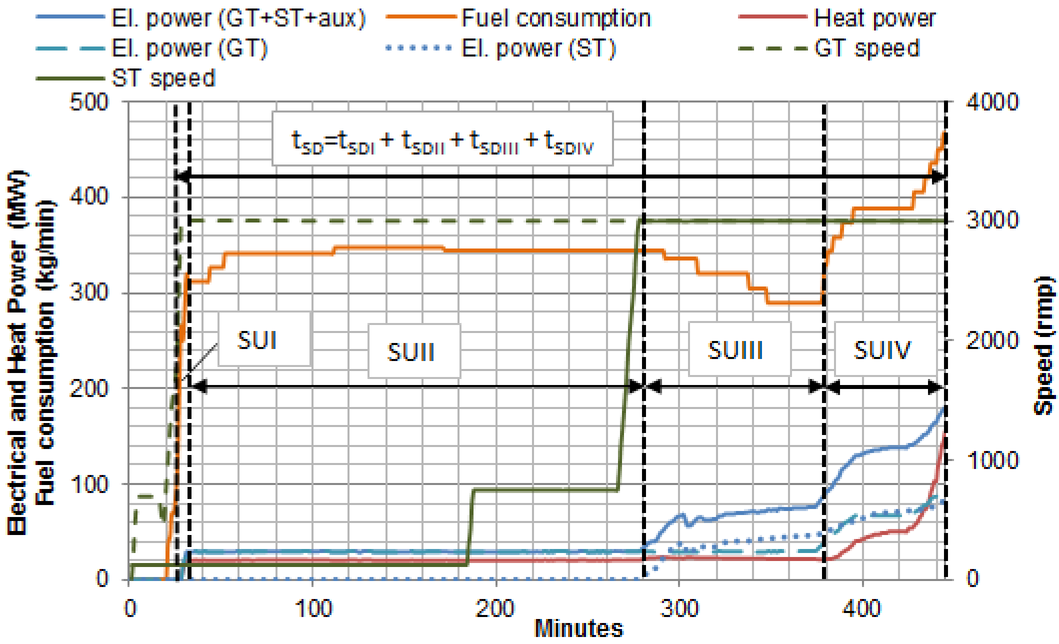


Fig. 3.3. Start-up of CCGT–2/2 unit [63].

Before the *SUI* the gas turbine is accelerated. It achieves ~ 30 MW and operates at this load during *SUII*, which is the longest period of start-up periods *(SUI, SUIII, SUIV)* due to the warm-up process of the equipment. At the end of *SUII*, the steam turbine is completely accelerated. The warming and loading of the steam turbine continue in *SUII*, but the gas turbine still operates at 30 MW. After the warm-up process the steam and gas turbines are loading in parallel until P_{eTHmin} during *SUIV*.

The fuel is consumed before the beginning of the start-up process, i.e., when $P_e = 0$ MW. The amount of fuel is less than 1 % that is why the calculation accuracy of start-up costs is not infringed.

The detailed information obtained from Fig. 3.3 is presented in Table 3.5.

Table 3.5

The Results of CCGT–2/2 Unit Start-up [63]

	SU1	**SUII**	**SUIII**	**SUIV**	**Σ**
Duration (t), min	9	242	96	71	418
Produced electricity (P_e), MWh	208	7114	6230	9412	22 964
Electrical power (P_e), MW	$0 \le P_{eSUI} \le 30$	$P_{eSUII} \sim 30$	$30 \le P_{eSUIII} \le 80$	$80 \le P_{eSUIV} \le 180$	$0 \le P_{eSUIV} \le 180$
GT	As $P_{eSUI}=GT_{SUI}$ => $0 \le GT_{SUI} \le 30$	$GT_{SUII} \sim 30$	$GT_{SUIII} \sim 30$	$30 \le GT_{SUIV} \le 98$	$0 \le GT_{SUIV} \le 98$
ST	$ST_{SUI} = 0$	$ST_{SUII} = 0$	$0 \le ST_{SUIII} \le 46$	$46 \le ST_{SUIV} \le 83$	$0 \le ST_{SUIV} \le 83$
Q	148	4 923	2 147	3 772	10 990
	The heat energy is produced by DH ECO. The heat energy production: $Q = f(P)$			The heat energy is produced by DH ECO and steam turbine. The	-

				heat energy production: $Q = f(P)$	
Consumed fuel (B), kg (m^3)	2 673 (3851)	82 933 (119 482)	30 348 (43 722)	27 422 (39 507)	143 376 (206 562)
Produced CO_2 emissions, t	7	225	82	74	388
Costs of period, €	768	26 273	9 632	8 727	45 400

According to Table 3.5, the following information on the start-up of CCGT–2/2 unit can be obtained:

- The duration of start-up ($t_{SUI, SUII, SUIII, SUIV}$) is 418 min: $k' = 1$ and $k''' + e = 418$;
- The amount of the produced power ($P_{SUI, SUII, SUIII, SUIV}$) is 22 964 MWh;
- The amount of the produced heat ($Q_{SUI, SUII, SUIII, SUIV}$) is 10 991 MWh;
- The total amount of the consumed fuel ($B_{SUI, SUII, SUIII, SUIV}$) is 143 376 kg or 206 563 m^3;
- The amount of the produced emissions ($CO_{2\ SUI, SUII, SUIII, SUIV}$) is 388 t;
- The costs of start-up ($C_{SUI, SUII, SUIII, SUIV}$) is 45 400 €.

Thus, the total duration of the transient modes (t_{TRM}) with outage of 72 h and cold start-up is 4756 minutes. The amount of the produced electricity (P_{eTRM}) is 24 794 MWh. The amount of the produced heat energy (Q_{TRM}) is 10 990 MWh. In this case, it is equal to the produced heat energy during the start-up. The total amount of the fuel (B_{TRM}) consumed during the transient mode is 149 836 kg or 215 870 m^3. The total emissions producing CO_2 are 405 t. The total costs of the transient modes (C_{TRM}) are 47 444 €.

3.3. Summary

1. The mathematical description of transient modes of CCGT technology is provided by dividing them into three blocks (shutdown, start-up, warm state preservation), and start-ups are additionally divided into four sub-blocks (start-up of gas turbine, warm-up and start-up of steam turbine, gas and steam turbine loading).
2. The mathematical description is approbated on the example of CCGT–2/2 unit of Riga TPP–2. The obtained results reflect that the start-up process is more complicated, slower and longer than the shutdown process. It is explained by the ongoing process during the start-up, i.e., warming of the elements of the equipment. Relatively less fuel is used and less carbon dioxide emissions are produced during the shutdown. That is why shutdown procedure mostly is omitted in the evaluation process. Moreover, the start-up time of CCGT–2/2 unit (especially time of cold start-up) should be reduced significantly.
3. The developed mathematical description of transient modes is value added, as it allows analysing the process of the transient modes and evaluating their efficiency and bottlenecks. The obtained results can be used in the research containing a cost-benefit analysis of the unit. The mathematical description can be supplemented by taking into account fixed costs, i.e., non-fuel costs, auxiliary costs and start-up preparation costs.

4 OPTIMISATION OF THE OPERATION MODE

There are a lot of academic papers, where the cycling operation of thermal power plants is optimised taking into account the transient modes (start-up, shutdown, warm state preservation). The papers differ with the rate of consideration of transient modes. For example, in [49] and [50] the objective function of a fossil fuel power plant (profit maximisation and minimisation of production costs) includes costs of transient modes, but their features (type, time, trajectory, etc.) are omitted. However, there are scientific papers, where significant attention is devoted to the features of transient modes. For instance, in [64], [65], [66] the start-ups are considered taking into account the preceding offline time of the unit. It was complicated by limiting the temperature increase and the heating speed [28], ramping constraints, including start-up, shutdown production trajectory, ramp rate and ramp-down constraints [47], [61], [67], and the change of thermal stress of the main equipment [68]. The rate of transient mode consideration differs from the content of academic papers. For instance, the consideration of transient modes is important, when the TPP operation is studied along with intermitted generation [69], [70] or when different activities are provided with transient modes to optimise the operation of a power plant as it is presented in this Chapter.

4.1. Approach to Optimisation of the Operation Mode

The presented approach is developed for a combined cycle gas turbine technology with the aim of optimising its cycling operation under the electricity market conditions. The principle of the approach can be applied to other thermal power technologies and situations as well. It consists of two models: *Evaluation Model* (*EM*) and *Optimisation Model* (*OM*). The *EM* processes the production data of a power plant and consequently determines the cycling characteristics of a power plant and input for *OM*. The *OM* ensures the extension of cycling operation range by shifting shutdown *"forward"* and start-up *"backward"* and, hence, the supplementary electricity is produced; the number of cycling periods is reduced and start-ups are replaced with less adverse ones.

The input parameters of *EM* (Fig. 4.1) are the following: produced electrical power (P), heat power (Q) and fuel consumption (B), price of heat (C_{th}), electricity (C_{el}) and fuel (C_f), emission factor (E_{CO2}) of fuel and its low heat value (LHV). The equations of *Evaluation Model* are presented in Table 4.1. The output of *EM* provides information about the number of cycling operation ranges ($\sum i$) and its periods (m_1, m_2, m_3, m_4), the duration of transient modes (h_1, h_2, h_3, h_4) and the type of start-ups, the obtained profit from electricity and heat production ($\sum \Pi_{th}, \sum \Pi_{el}, \sum \Pi_{th+el}$) and characteristics, which are shown in detail in Table 4.1 and Table 4.2.

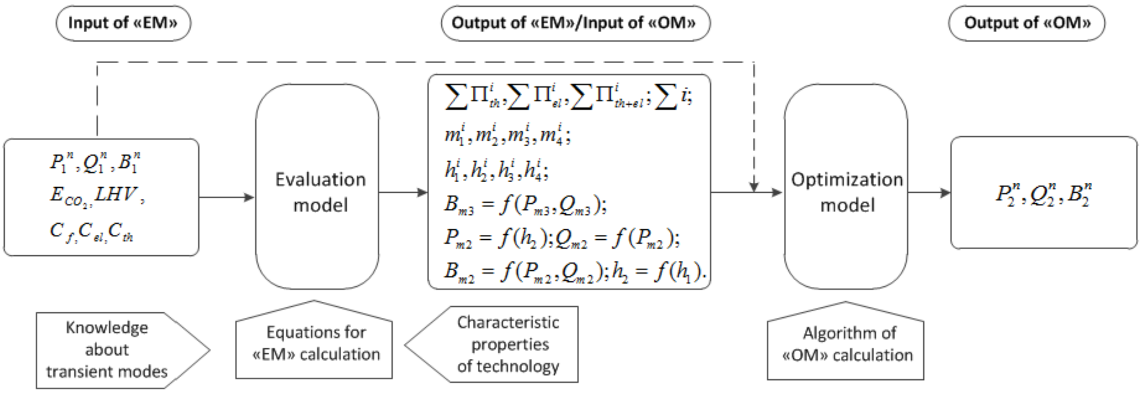


Fig. 4.1. The flow chart of the developed approach [58].

The input of *OM* is the output of *EM* (the obtained characteristics and values of parameters) and the values of *EM* input parameters describe the initial situation in *Optimisation Model*. The calculation of *OM* is based on the algorithm presented in Section 4.1.2. The outputs of *OM* are the new values of electrical power ($P^n{}_2$), heat power ($Q^n{}_2$) and consumed fuel ($B^n{}_2$).

4.1.1. Development of the *Evaluation Model*

The cycling operation range (i) is divided into four periods: warm state preservation (m_1), start-up (m_2), operation above technical minimum (m_3) and shutdown (m_4), whose duration is h_1, h_2, h_3, h_4, respectively (Fig. 4.2).

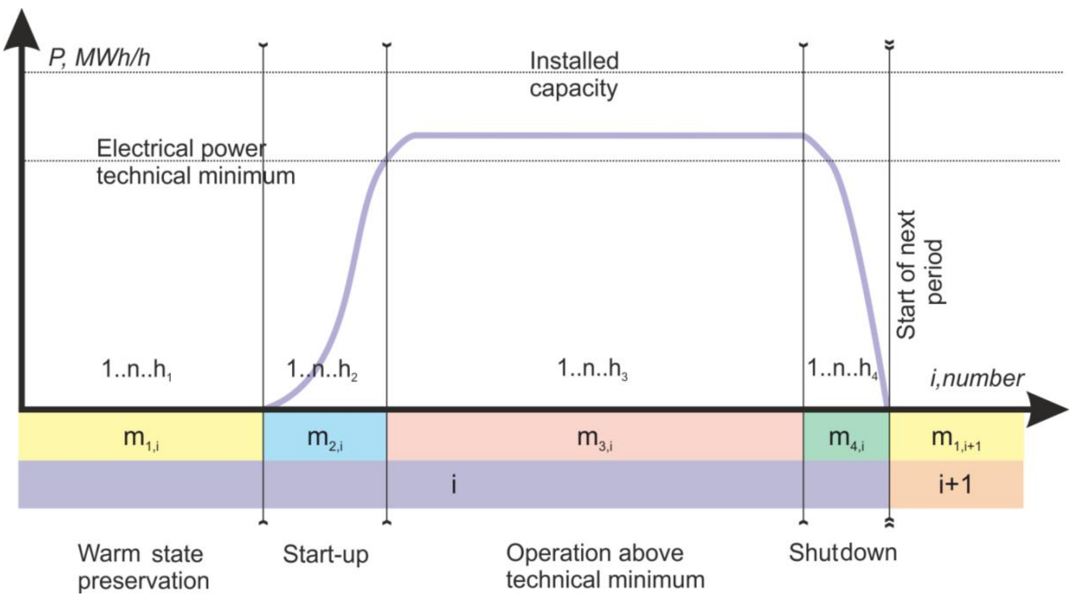
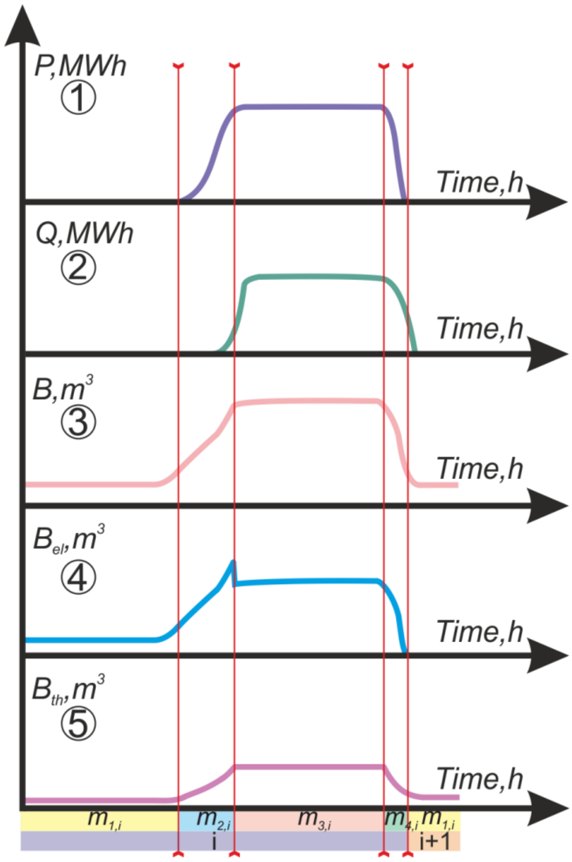


Fig. 4.2 The model of cycling operation range (i) [58].

The changes in electrical power *(P)*, heat power *(Q)*, fuel consumption *(B)* during the cycling operation range are illustrated in Fig. 4.3.



① The change in electrical power is taken as a reference point, i.e., the division of cycling operation range into m_1, m_2, m_3 and m_4.
② The heat power falls behind the electrical power in m_2 and m_3. At the end of m_4 and at the beginning of $m_{1,i+1}$ heat power is greater than zero and electrical power is equal to zero. The value of heat power in $m_{1,i+1}$ is shifted to the warm state preservation of a new cycling operation range, i.e., $i+1$.
③ The fuel is consumed, when the unit is out of operation to preserve the warm state of the unit. If outage is too long, then the warm state is not preserved. The total amount of the consumed natural gas for electricity and heat production is also taken as input data in the mathematical model of evaluation of cycling operation range.
④,⑤ Natural gas for heat and electricity production in m_3 and m_4 is calculated using Eqs. (4.1) and (4.2), respectively. Due to short duration of m_4 (less than 30 minutes), the consumption of fuel is calculated for both periods simultaneously. Fuel consumption for heat and electricity production in m_1 and m_2 is calculated proportionally to the produced heat and electricity in m_1 and m_2. It is performed using Eqs. (4.3) and (4.4). $Q_{m1,i} = Q_{m1,i-1}$ due to the fact that at the end of m_4 and at the beginning of $m_{1,i+1}$ heat power is greater than zero and electrical power is equal to zero.

Fig. 4.3 The schematic change in electricity, heat and fuel during the cycling operation range *"i"* [58].

Eqs. (4.1)–(4.9) of *EM* (Table 4.1) are developed based on information provided in Fig. 4.3 and the previously obtained knowledge about transient modes and characteristic properties of a combined cycle gas turbine technology in [24], [63].

Table 4.1

Equations of the Evaluation Model [58]

Equation	Unit	Explanation	Eq. No
$B^i_{th\,n,m\,3..4} = \dfrac{Q^i_{n,m\,3..4}}{0.93 \times LHV}$	[m³/h]	The consumption of fuel for heat production in periods: operation above technical minimum and shutdown (Coefficient 0.93 describes the efficiency of heat production in the cogeneration mode)	(4.1)
$B^i_{el\,n,m\,3..4} = B^i_{n,m\,3..4} - B^i_{th\,n,m\,3..4}$	[m³/h]	The consumption of natural gas for electricity production in periods: operation above technical minimum and shutdown	(4.2)
$B^i_{th\,n,m\,1..2} = B^i_{n,m\,1..2} \times \dfrac{\sum_{m_1}^{m_2} \sum_{n=1}^{n=N} Q^i_{n,m}}{\sum_{m_1}^{m_2} \sum_{n=1}^{n=N} P^i_{n,m}}$	[m³/h]	The consumption of natural gas for heat production in periods: warm state preservation and start-up	(4.3)
$B^i_{el\,n,m\,1..2} = B^i_{n,m\,1..2} - B^i_{th\,n,m\,1..2}$	[m³/h]	The consumption of natural gas for electricity production, when the cogeneration unit is in warm state	(4.4)

		preservation or it starts up	
$MC^i_{el_{avg}\,n,m} = \dfrac{\sum\limits_{m_1}^{m_4}\sum\limits_{n=1}^{n=N}(B^i_{el_{n,m}} \times C^i_{f_{n,m}} + B^i_{el_{n,m}} \times LHV \times E_{CO_2} \times C^i_{CO_{2n,m}})}{\sum\limits_{m_2}^{m_4}\sum\limits_{n=1}^{n=N} P^i_{n,m}}$	[€/MWh]	The average marginal cost of electricity per cycling operation range	(4.5)
$MC^i_{th_{avg}\,n,m} = \dfrac{\sum\limits_{m_1}^{m_4}\sum\limits_{n_1}^{n}(B^i_{th_{n,m}} \times C^i_{f_{n,m}} + B^i_{th_{n,m}} \times LHV \times E_{CO_2} \times C^i_{CO_{2n,m}})}{\sum\limits_{m_2}^{m_4}\sum\limits_{n_1}^{n=N} Q^i_{n,m}}$	[€/MWh]	The average marginal cost of heat per cycling operation range	(4.6)
$\Pi^i_{th} = \sum\limits_{m_1}^{m_4}\sum\limits_{n=1}^{n=N}(C^i_{th_{n,m}} \times Q^i_{n,m} - B^i_{th_{n,m}}(C^i_{f_{n,m}} + LHV \times E_{CO_2} \times C^i_{CO_{2n,m}}))$	[€]	The profit of the produced heat in cycling operation ranges per year	(4.7)
$\Pi^i_{e} = \sum\limits_{m_1}^{m_4}\sum\limits_{n=1}^{n=N}(C^i_{e_{n,m}} \times P^i_{n,m} - B^i_{e_{n,m}}(C^i_{f_{n,m}} + LHV \times E_{CO_2} \times C^i_{CO_{2n,m}}))$	[€]	The profit of the produced electricity in cycling operation ranges per year	(4.8)
$\Pi^i = \Pi^i_e + \Pi^i_{th}$	[€]	The total profit of heat and electricity production in cycling operation ranges per year	(4.9)

Fig. 4.4 illustrates the simultaneous change in three parameters: natural gas consumption, heat power and electrical power. Equation 4.10 presents the mathematical relation of these parameters; it is used as the input of *OM*.

$$B_{m_3} = a_1 \times P_{m_3} + a_2 \times Q_{m_3} + a_3. \tag{4.10}$$

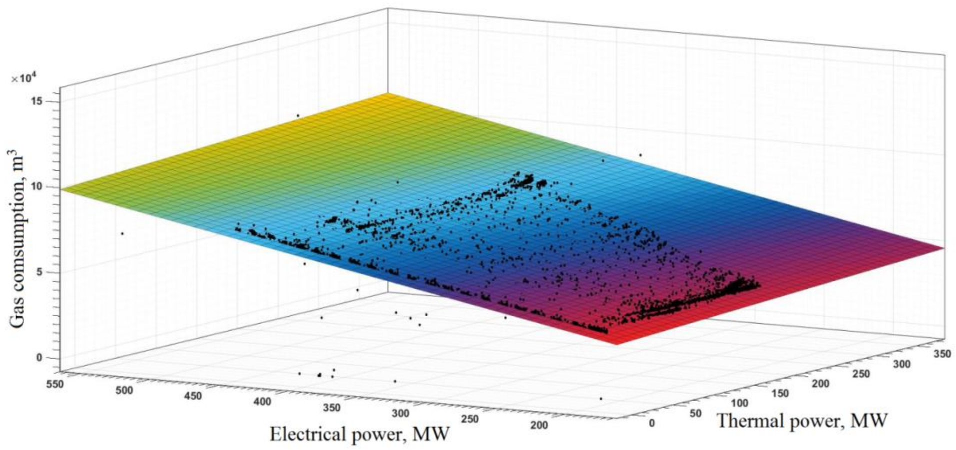


Fig. 4.4. Consumption of natural gas as a function of electrical and heat power [58].

Table 4.2 reflects the obtained start-up characteristics of CCGT technology. They are the following:

- the duration of start-up from the continuation of warm state preservation $h_2=f(h_1)$;
- the consumed fuel for production of electricity and heat $B_{m2}=f(P_{m2},Q_{m2})$ during start-up (m_2);
- the change in electrical power during start-up from the type of start-up $P_{m2}=f(h_2)$;
- the change in heat power from electrical power $Q_{m2}=f(P_{m2})$ during start-up (m_2).

Table 4.2

Start-up Characteristics of CCGT Technology [58]

Type of start-up	Function	Fitness: R-square
All	$h_2 = a_1 \times h_1 + a_0$	0.9904
Cold	$B_{m2} = b_1 \times P_{m2} + b_1' \times Q_{m2} + b_0$	0.9655
	$P_{m2} = c_2 \times h_2^2 + c_1 \times h_2 + c_0$	0.9415
	$Q_{m2} = d_3 \times P^3_{m2} + d_2 \times P^2_{m2} + d_1 \times P_{m2} + d_o$	0.7916
Warm	$B_{m2} = u_1 \times P_{m2} + u_1' \times Q_{m2} + u_0$	0.9833
	$P_{m2} = k_1 \times h_2 + k_0$	0.9393
	$Q_{m2} = l_2 \times P^2_{m2} + l_1 \times P_{m2} + l_0$	0.8364
Hot	$B_{m2} = r_1 \times P_{m2} + r_1' \times Q_{m2} + r_0$	0.9739
	$P_{m2} = v_1 \times h_2 + v_0$	0.7361
	$Q_{m2} = z_2 \times P^2_{m2} + z_1 \times P_{m2} + z_0$	0.9006

The fitness of mathematical relations (Table 4.2), i.e., coefficient of determination (R-squared) reflects a good correlation among the parameters.

4.1.2. Development of the *Optimisation Model*

The concept of optimisation task (Fig. 4.5) and its calculation algorithm (Fig. 4.6) are based on the selection method and principles of the Nord Pool intra-day physical market.

According to the developed approach, the optimisation of cycling operation is achieved through the extension of cycling operation range (Fig. 4.5). The optimisation time interval is limited; it is 24 hours, i.e., $\sum h_{1,2,3,4} = 24$. It is expected to gain additional profit from the additionally produced energy in the market and decrease the adverse influence of cycling operation on technical resources of the equipment through the reduction of start-ups and change of their types to the less adverse ones. The latter is taken for granted without numerical evidence based on literature [5], [26], [71], [72] and know-how.

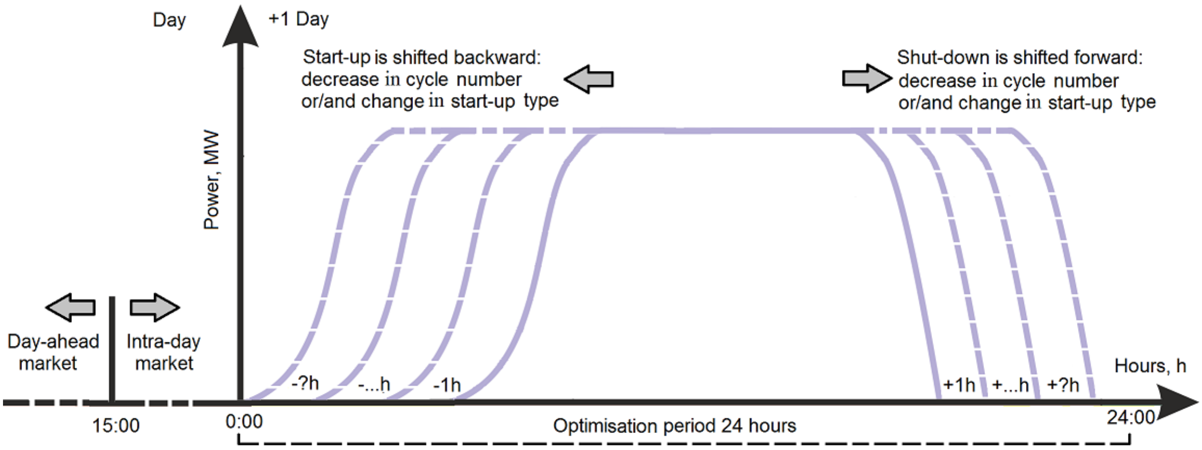


Fig. 4.5. A traditional example of an optimisation task concept [58].

The situation varies in the electricity market, for instance, in the first additional hour of operation the profit is $\Pi_1 > 0$, in the second – $\Pi_2 < 0$, but $\sum\Pi_{1,2} > 0$, because $\Pi_1 >> \sum\Pi_{1,2}$. In the third additional hour the profit is $\Pi_3 > 0$, but $\sum\Pi_{1,2,3} < \Pi_1$ because $\Pi_1 >> \Pi_3$. The dilemma occurs, i.e., the maximum profit is obtained in the first hour, but the probability to reduce the adverse influence of cycling operation of technical resources of the equipment is smaller than in the second and third hours. However, the total gained profit for the first and second or for the first, second and third hours is positive, but is less than in the first additional hour. That is why the optimisation task can be implemented in two ways: referring to the maximum profit (Optimisation No. 1 (Eq. 4.11)) or referring to the positive profit and reduction of negative impact of cycling operation on technical resources of the equipment by maximising the hours in operation (n) under condition that the gained profit has to be positive (Optimisation No. 2 (Eq. 4.12)). It is expressed through the maximisation of operation hours (n).

The objective function for Optimisation No. 1 is as follows:

$$\sum_i [\sum_{m_1}^{m_4} \sum_{n=1}^{n=N} (C^i_{e_{n,m}} \times P^i_{n,m} - B^i_{e_{n,m}} (C^i_{f_{n,m}} + LHV \times E_{CO_2} \times C^i_{CO_{2_{n,m}}})) + \ldots$$

$$\ldots + \sum_{m_1}^{m_2} \sum_{n=1}^{n=N} (C^i_{th_{n,m}} \times Q^i_{n,m} - B^i_{th_{n,m}} (C^i_{f_{n,m}} + LHV \times E_{CO_2} \times C^i_{CO_{2_{n,m}}}))] \rightarrow \max\Pi, \quad (4.11)$$

Subject to

$i = 1,\ldots,I$, $i \in Z_+$

$n = 1,\ldots,N$, $n \in Z_+$

$N \leq 24$

$P = 0$, $Q = 0$ *if* $m = m_1$

$0 < P \leq P_{m2}$, $0 < Q \leq Q_{m2}$ *if* $m = m_2$

$P^{min} < P \leq P^{max}$, $Q^{min} < Q \leq Q^{max}$ *if* $m = m_3, m_4$

The objective function for Optimisation No. 2 is as follows:

$$\sum_i [\sum_{m_1}^{m_4} \sum_{n=1}^{n=N} (C^i_{e_{n,m}} \times P^i_{n,m} - B^i_{e_{n,m}} (C^i_{f_{n,m}} + LHV \times E_{CO_2} \times C^i_{CO_{2_{n,m}}})) + \ldots$$

$$\ldots + \sum_{m_1}^{m_2} \sum_{n=1}^{n=N} (C^i_{th_{n,m}} \times Q^i_{n,m} - B^i_{th_{n,m}} (C^i_{f_{n,m}} + LHV \times E_{CO_2} \times C^i_{CO_{2_{n,m}}}))] \rightarrow \max n \,, \quad (4.12)$$

Subject to

$$i = 1,\ldots,I \,,\; i \in Z_+$$

$$n = 1,\ldots,N \,,\; n \in Z_+$$

$$N \leq 24$$

$$\begin{cases} P = 0 \\ Q = 0 \end{cases} \qquad if\ m=m_1$$

$$\begin{cases} 0 < P \leq P_{m2} \\ 0 < Q \leq Q_{m2} \end{cases} \qquad if\ m=m_2$$

$$\begin{cases} P^{\min} < P \leq P^{\max} \\ Q^{\min} < Q \leq Q^{\max} \end{cases} \qquad if\ m=m_3, m_4$$

$$\Pi > 0,\ \Pi \in R_+$$

The input of *OM* algorithm (Fig. 4.6) is production data of technologies (*P*, *Q*, *B*, etc.) and the obtained characteristics in Table 4.2. Initially, the calculation day is identified in line with the Nord Pool market principles (the total number of days is 365/366). After the extension of technology, working time is calculated for each identified day by shifting shutdown *"forward"* and start-up *"backward"* until the optimal solution is achieved in line with Optimisation No. 1 and No. 2. The obtained results are accumulated while the calculations for all days of the year are performed. After they are finished, the appropriate solution is found.

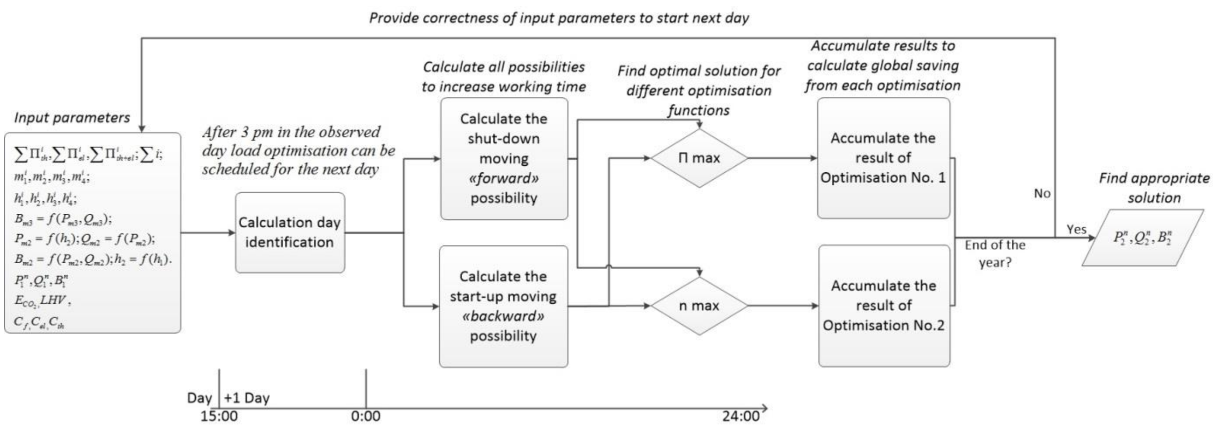


Fig. 4.6 The algorithm for optimisation model calculation [58].

4.1.3. The Practical Application of the Developed Approach

The *EM&OM* approach could be used in different Nord Pool physical markets: day-ahead and intraday to ensure more profitable operation of a thermal power plant or real time/balance market to evaluate the possibility of producing additional energy when power deficit is observed, but its performance changes depending on the type of a physical market (Table 4.3).

Table 4.3

The Performance of *EM&OM* Approach in Different Nord Pool Physical Markets [73]

Parameter	**Type of a market**		
	Day-ahead market	**Intraday market**	**Balancing market**
Benefits of using the *EM&OM* approach	The integration of approach in TPP optimisation models to prepare the bids for submission in the market. The accuracy of optimisation models is increased and the planning of conventional generation operation becomes more precise and profitable because the features of start-ups and the proposed principles of cycling operation improvement are taken into consideration.	The observation of cycling operation features and the proposed principles of its improvement provide more profitable operation of based load TPP, when bids are approved	The consideration of start-up features and the proposed principles of cycling operation improvement ensure the possibility to evaluate the production of additional energy in areas with power deficit.
The necessity of additional calculations	The forecast of input data (ambient air temperature, heat load, electricity price, etc.)	Investigating the impact on other generation units (portfolio)	Investigating the impact on other generation units (portfolio)

The developed optimisation model can be integrated in the unit commitment model to take into consideration the cycling operation of thermal power plants and increase the accuracy of UC model. If the introduced optimisation model is not going to be integrated in the UC model (sub-section 4.2.2), additional calculations are needed in order to check the influence of additionally produced energy on generation portfolio (Sub-section 4.2.3).

4.2. Approbation of the Developed Approach

4.2.1. Results of the *Evaluation Model*

The CCGT–2/1 unit cycling operation range was analysed for 2016 in line with the approach introduced in Sub-section 4.1.1. There were 57 start-ups or *i* cycling operation range: 15 hot start-ups, 19 warm start-ups and 23 cold start-ups.

The cold start-up was 2 times longer than the warm start-up and 4 times longer than the hot start-up. The average duration of cold start-up was more than 4 hours (Fig. 4.7).

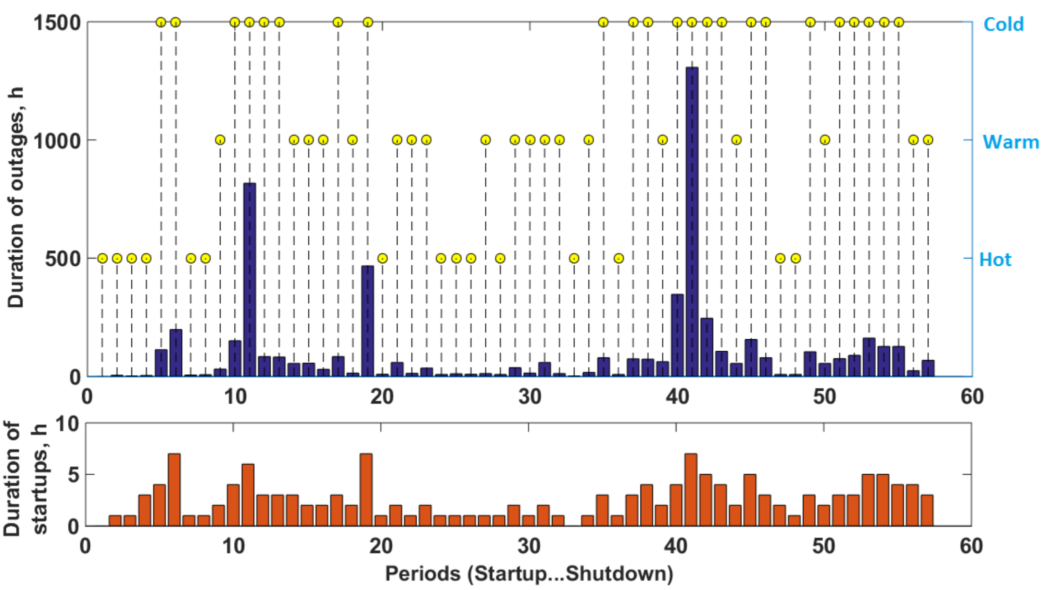


Fig. 4.7. Types of start-ups, duration of start-ups and outages [58].

During the cold start-up, approximately 2 times more natural gas was consumed than for the warm start-up and approximately 3 times more than for the hot start-up. The average consumed natural gas for the cold start-up was 9.8×10^4 m^3 (Fig. 4.8).

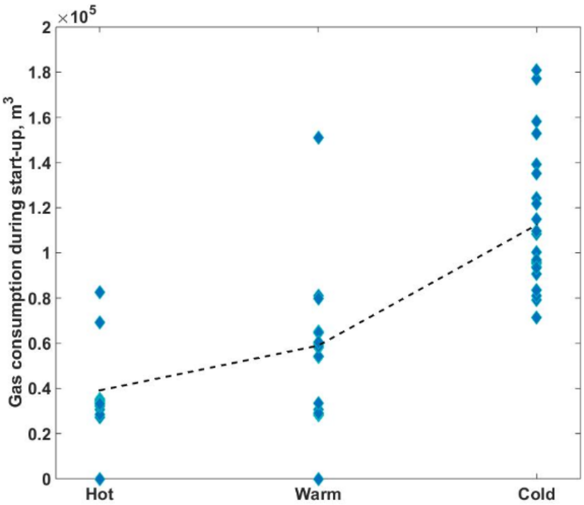


Fig. 4.8. The consumption of natural gas versus the start-up type [58].

In 2016, the longest cycling operation range was 448 hours and the shortest – 8 hours. The average duration of cycling operation range was 45 hours (Fig. 4.9). The maximum values of benefit from electricity and heat realisation were 3.2×10^6 € and 175.4×10^3 €, respectively. The maximum values of losses (electricity marginal cost exceeds electricity price) from electricity and heat productions were 140×10^3 € and 8.5×10^3 €, respectively. The profit from electricity and heat realisation of CCGT–2/1 unit was 6.0×10^6 € and 400.0×10^3 € in 2016. The obtained results indicate that the realisation of electricity provides higher profit for a power plant than the realisation of heat energy. The total profit from heat and electricity realisation of CCGT–2/1 unit was 6.4×10^6 € in 2016.

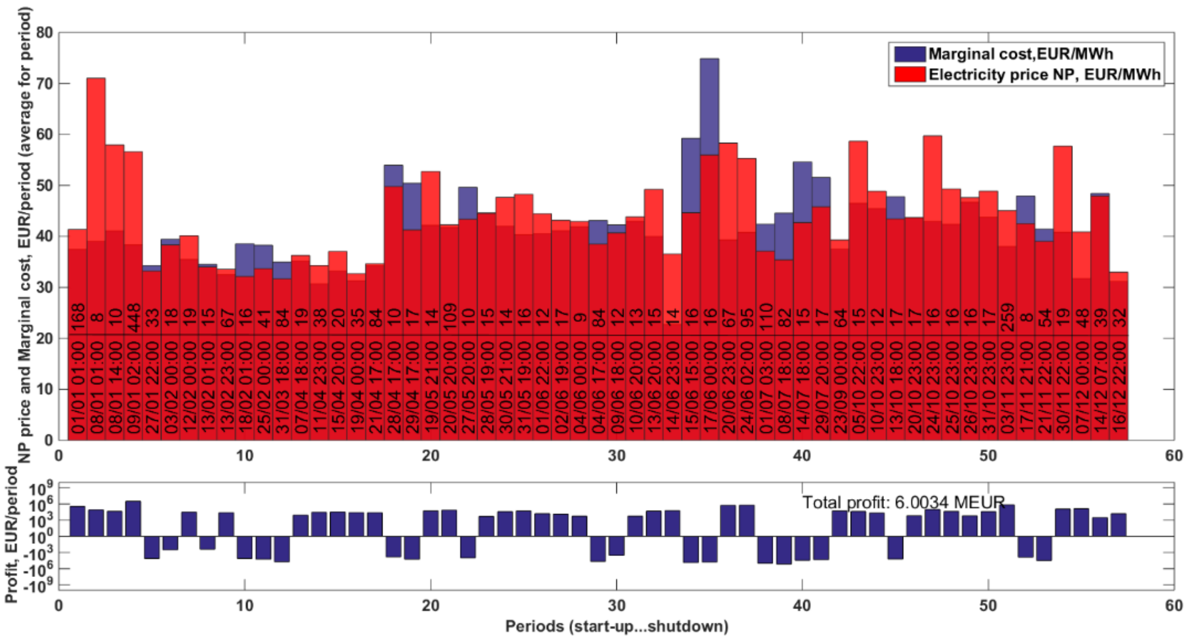


Fig. 4.9. Average Nord Pool price, average electricity marginal costs and profit from electricity realisation in cycling operation ranges *"i"* [58].

4.2.2. Results of the *Optimisation Model*

Table 4.4 shows the results of shifting shutdown *"forward"* and start-up *"backward"* by extension of cycling operation range for two optimisation tasks: $\Pi \rightarrow max$ and $n \rightarrow max$. The results of *Optimisation No. 1* demonstrate that the number of cycling operation ranges remains the same, i.e., i = 57. The number of warm start-ups and cold start-ups reduces by 4 and 2, respectively, that is why the number of hot start-ups increases by 6. The increment of operation hours is 228 hours and income is 1.42 M€. The results of *Optimisation No. 2* reflect that the number of warm and cold start-ups reduces by 4 and 2, respectively, but hot start-ups increase by 2 due to the reduction of cycling operation from 57 to 53. The increment of operation hours is 275 hours and income is 1.27 M€.

Table 4.4

Results of Optimisation Tasks [58]

	Income, [M€]	$\sum i$, [number]	Operation hours, [h]	Number of hot start-ups, [h]	Number of warm start-ups, [h]	Number of cold start-ups, [h]
Before optimisation	6	57	2571	15	19	23
Optimisation No. 1	7.42	57	2799	21	15	21
Optimisation No. 2	7.27	53	2846	17	15	21

Having compared the results of two optimisation tasks, the author concludes that *Optimisation No. 1* ensures higher income than *Optimisation No. 2*, i.e., 1.42 M€ and 1.27 M€, respectively. The difference is insignificant, approximately 150 k€. In turn, the results of *Optimisation No. 2* have demonstrated the decrease in cycling operation ranges by four cycles, whereas *Optimisation No. 1* have not. The optimisation under condition $n \rightarrow max$ is preferable.

For instance, Fig. 4.10 represents a graphical illustration of changes in CCGT–2/1 unit operation (the probability of start-up and shutdown) before (the dashed red and blue line) and after (the solid red and blue line) *Optimisation No. 2*. The red lines describe the duration of outages and blue lines characterise the duration of cycling operation. The continuation of cycling operation ranges is longer, i.e., the blue solid line under the dashed blue line or the shifting of blue dashed line to the right is observed in Fig. 4.10. In turn, the duration of outages becomes rarer and shorter, i.e., mainly the red solid line is under the dashed red line or the shifting of red dashed line to the left is noticed in Fig. 4.10.

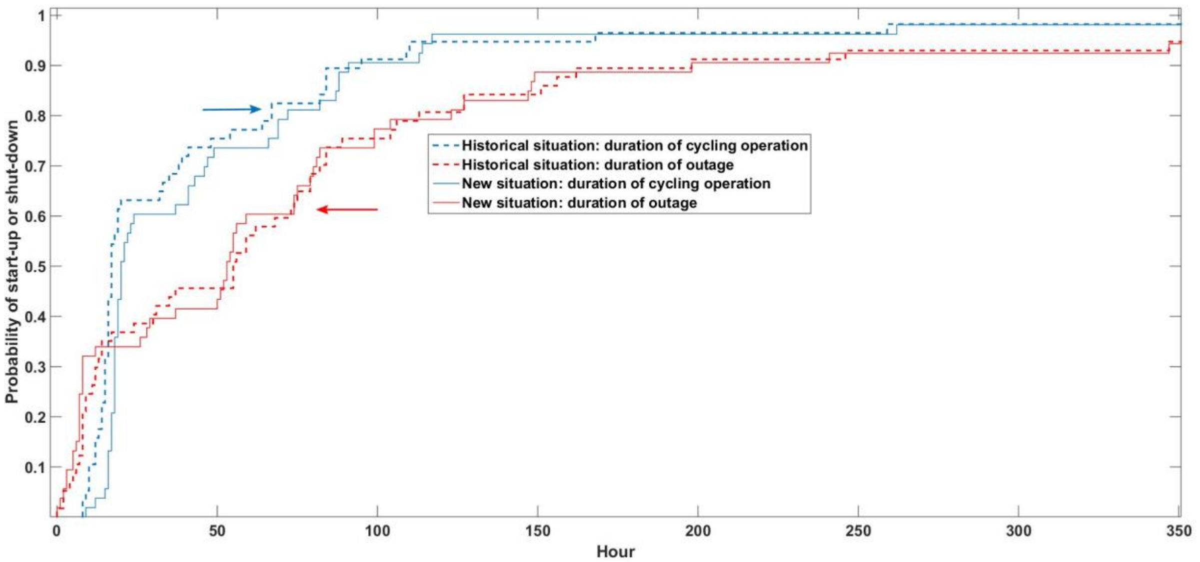


Fig. 4.10. Probability of start-ups and shutdowns before (historical situation) and after (new situation) *Optimisation No. 2* [58].

4.2.3. Approbation of the Approach in the Intraday Market: Impact on the Generation Portfolio

In Sub-sections 4.2.1 and 4.2.2, the developed *EM&OM* approach is verified on the example of CCGT–2/1 unit of Riga TPP–2 in the Nord Pool intraday physical market. It is when the results of unit commitment and electricity price are known, i.e., the dashed box in Fig. 4.11. Y'^{1} denotes the first cogeneration unit and Y'^{2} – the second cogeneration unit of generation portfolio Y', which is Riga TPP–2.

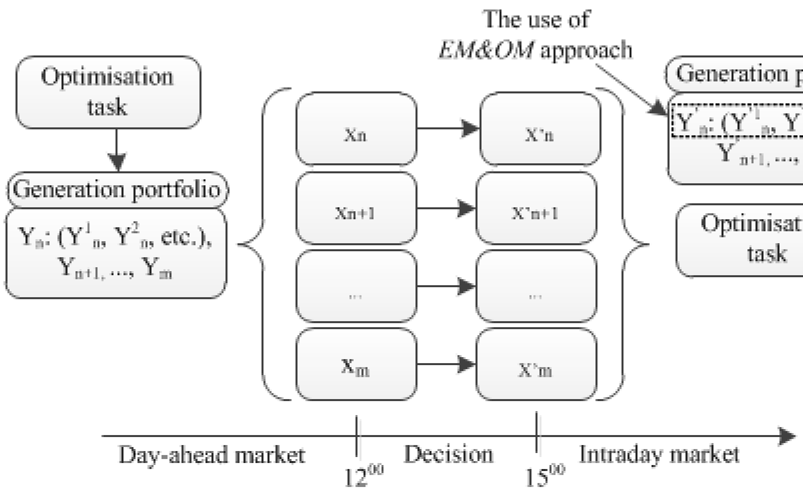


Fig. 4.11. The example of use of the *EM&OM* approach in the intraday market [73]
(Y_n, Y_{n+1}, Y_m denote the generation portfolio before bid submission to the Nord Pool market; x_n, x_{n+1}, x_m – the submitted bids to the market; x'_n, x'_{n+1}, x'_m – the approved bids on the Nord Pool market; Y'_n, Y'_{n+1}, Y'_m – the generation portfolio after bid approval on the Nord Pool market and optimisation provision in line with the approved bids).

According to Table 4.3, if the *EM&OM* approach is used in the intraday market, then the additional calculations are needed: the influence of the optimised generation unit should be investigated on other generation unit or portfolio. That is why in this sub-section this impact is assessed by introducing the evaluation algorithm, which consists of the optimised CCGT–2/1 according to the *EM&OM* approach and changes in the generation portfolio of the cogeneration units (CCGT–2/1 and CCGT–2/2). The evaluation algorithm is created for thermal power plants, which consist of the two CCGT units (Fig. 4.12).

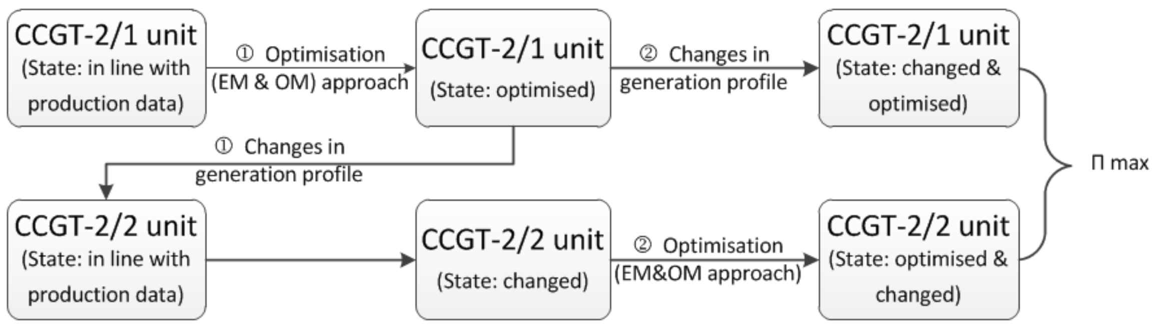


Fig. 4.12. The block scheme of the evaluation algorithm [73].

Initially, the operation of CCGT–2/1 unit is optimised in line with the *EM&OM* approach. Additionally, the produced power and heat energy by the first cogeneration unit are compensated by CCGT–2/2 unit, i.e., the changes in CCGT–2/2 unit generation profile are observed. Then the *"changed"* generation profile of CCGT–2/2 unit is optimised by the *EM&OM* approach making changes in the optimised CCGT–2/1 unit profile. The optimisation of CCGT–2/2 unit in line with the *EM&OM* approach is provided and/or changes in the generation portfolio of CCGT–2/1 unit are implemented, if it is possible to ensure them. For example, the second unit is operated in parallel with the first unit, the load of cogeneration units is enough to make changes in the generation portfolio, and it is possible to save the power and heat balance.

The objective function of the evaluation algorithm is profit (Π) maximisation of Riga TPP–2 (4.13):

$$\sum_{i=1}^{i=k}((\Pi'_{CCTG-2/1_i}-\Pi_{CCGT-2/1_i})+(\Pi'_{CCTG-2/2_i}-\Pi_{CCGT-2/2_i}))\rightarrow \max\Pi\,, \tag{4.13}$$

Subjected to

$i=1,..k;\ i\in Z_+$

$P^{\min}_{CCGT-2/1}<P_{CCGT-2/1}\le P^{\max}_{CCGT-2/1}$

$Q^{\min}_{CCGT-2/1}<Q_{CCGT-2/1}\le Q^{\max}_{CCGT-2/1}$

$P^{\min}_{CCGT-2/2}<P_{CCGT-2/2}\le P^{\max}_{CCGT-2/2}$

$Q^{\min}_{CCGT-2/2}<Q_{CCGT-2/2}\le Q^{\max}_{CCGT-2/2}$

$\sum_{i=1}^{i=k}P_{1i}=\sum_{i=1}^{i=k}P_{2i}$ Electrical power balance. P_1 is the sum of CCGT–2/1 and CCGT–2/2 units electrical power in line with the production data. P_2 is the sum of CCGT–2/1 and CCGT–2/2 units electrical power in the changed and optimised states, respectively.

$\sum_{i=1}^{i=k}Q_{1i}=\sum_{i=1}^{i=k}Q_{2i}$ Heat power balance. Q_1 is the sum of CCGT–2/1 and CCGT–2/2 units heat power according to the production data. Q_2 is the sum of CCGT–2/1 and CCGT–2/2 units heat power in the changed and optimised states, respectively.

where

$\Pi_{CCGT-2/1_i}$ profit of the first cogeneration unit according to the production data, €;

$\Pi'_{CCTG-2/1_i}$ profit of the first cogeneration unit in the changed state, €;

$\Pi_{CCTG-2/2_i}$ profit of the second cogeneration unit in line with the production data, €;

$\Pi'_{CCTG-2/2_i}$ profit of the second cogeneration unit in the optimised state, €;

i number of cycling operation ranges, number;

P electrical power, MW;

Q heat power, MW.

The profit of cogeneration units is calculated taking into account the marginal costs of cogeneration units, which hold on two components: natural gas and carbon dioxide.

Fig. 4.13 presents the example of performance results of the evaluation algorithm. In line with the *EM&OM* approach, the start-up of CCGT–2/1 unit was shifted to 15 hours backward. The start-up time was at 0.00 am instead of 3.00 pm. Due to high electricity price, in this period (from 0.00 am to 3.00 pm) the electrical power of CCGT–2/1 unit was higher by 50 MW than that after 3.00 pm. To save the power and heat balance of Riga TPP–2, the power of the CCGT–2/2 was was reduced to the technical minimum, i.e., 149 MW.

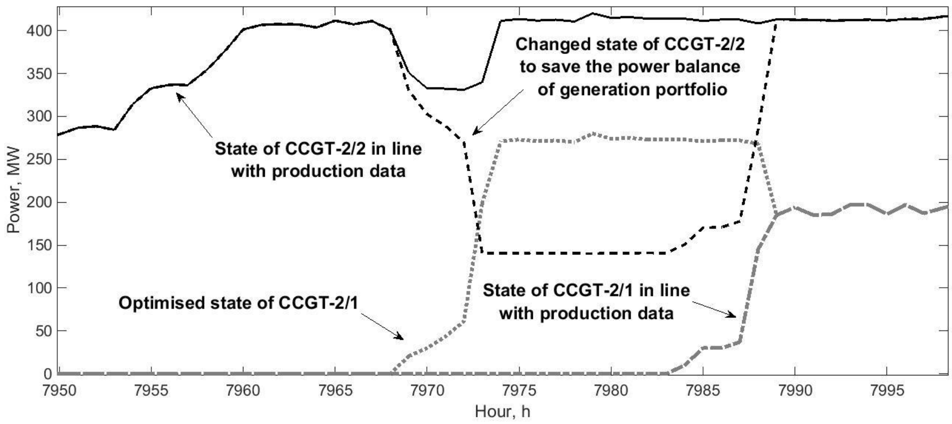


Fig. 4.13. The example of performance results of the evaluation algorithm [73].

In line with the evaluation algorithm (Fig. 4.12) after the optimisation of CCGT–2/1 unit and changes in CCGT–2/2 unit generation profile, the optimisation of CCGT–2/2 unit and changes in the optimised CCGT–2/1 unit profile should be performed. According to the situation demonstrated in Fig. 4.13, they were not made because there were not any possibilities.

In Sub-section 4.1.2, the *EM & OM* approach has been performed simultaneously for start-ups and shutdowns. In this sub-section, it is also performed separately for start-up and shutdown:

- Scenario No. 1: Start-ups are shifted *"backward"*;
- Scenario No. 2: Shutdowns are shifted *"forward"*;
- Scenario No. 3: Start-ups are shifted *"backward"* and shutdowns *–"forward"*.

The obtained results are presented in Table 4.5. The positive result is obtained in Scenario No. 1, i.e., additional profit at the value of 23 800 € for additional 24 operation hours. The last two scenarios (Scenarios No. 2 and No. 3) ensure an increase in operation hours by 29 and 59 hours, but provide a negative profit in monetary terms by -102 600 € and -78 600 €, respectively.

Table 4.5

Interpretation of Optimisation Results [73]

Parameters & Scenarios	**The value of parameter before optimisation**	**The value of parameter after optimisation**	**Difference between parameters after and before optimisation**
Scenario No. 1:	**Start-ups are shifted *"backward"***		
Gain/losses, [€]	17.2537×10^6	17.2775×10^6	23 800
Operation hours of both cogeneration units, [h]	5744	5768	24
Scenario No. 2:	**Shutdowns are shifted *"forward"***		
Gain/losses, [€]	17.2537×10^6	17.1511×10^6	- 102 600
Operation hours of both cogeneration units, [h]	5744	5773	29

Scenario No. 3:	Start-ups are shifted *"backward"* and shutdowns – *"forward"*		
Gain/Losses, [€]	17.2537×10^6	17.1751×10^6	- 78 600
Operation hours of both cogeneration units, [h]	5744	5803	59

In case of Scenario No. 1, the additional profit is obtained due to the reduction of time spent in warm state preservation. This has resulted in more efficient start-up. In their turn, Scenarios No. 2 and No. 3 provide negative profit because the optimisation of CCGT–2/1 unit has led to CCGT–2/2 unit's electrical power reduction to the technical minimum. The specific consumption of natural gas of the second cogeneration unit has increased. As a result, the efficiency of CCGT–2/2 unit has decreased.

4.3. Summary

1) An approach (*EM&OM*) ensures CCGT power plant operation in a more flexible, efficient and profitable way. The presented concept of the developed approach can be adapted to different thermal power plant technologies and physical markets by changing the characteristics and principles, respectively.
2) The approach is approbated on the example of Riga TPP–2. The results from a real-life case study have shown that the developed approach is accurate and computationally efficient. The use of this approach ensures the additional income and reduces negative impact of cycling operation on technical resources of the equipment that is why it is recommended to incorporate the developed approach in the generation portfolio of Riga TPP–2.
3) The use of *EM&OM* approach in the intraday market can be both efficient (with additional profit) and inefficient (with losses). The positive result (additionally gained profit) of the use of the *EM&OM* approach in the intraday market can be achieved by extending the generation portfolio and adding a different generation unit, for example, natural gas and hydropower units.

5 GENERAL ALGORITHM FOR TECHNICAL AND ECONOMIC EVALUATION OF TECHNOLOGIES

The algorithm for technical and economic evaluation of technologies is based on the evaluation algorithm. It is presented in Fig. 5.1. The aim of this algorithm is to answer the questions: Is the increased flexibility level of the power plant by technology economically feasible and ensures the additional profit? How different parameters influence the payback of technology (sensitivity analysis)?

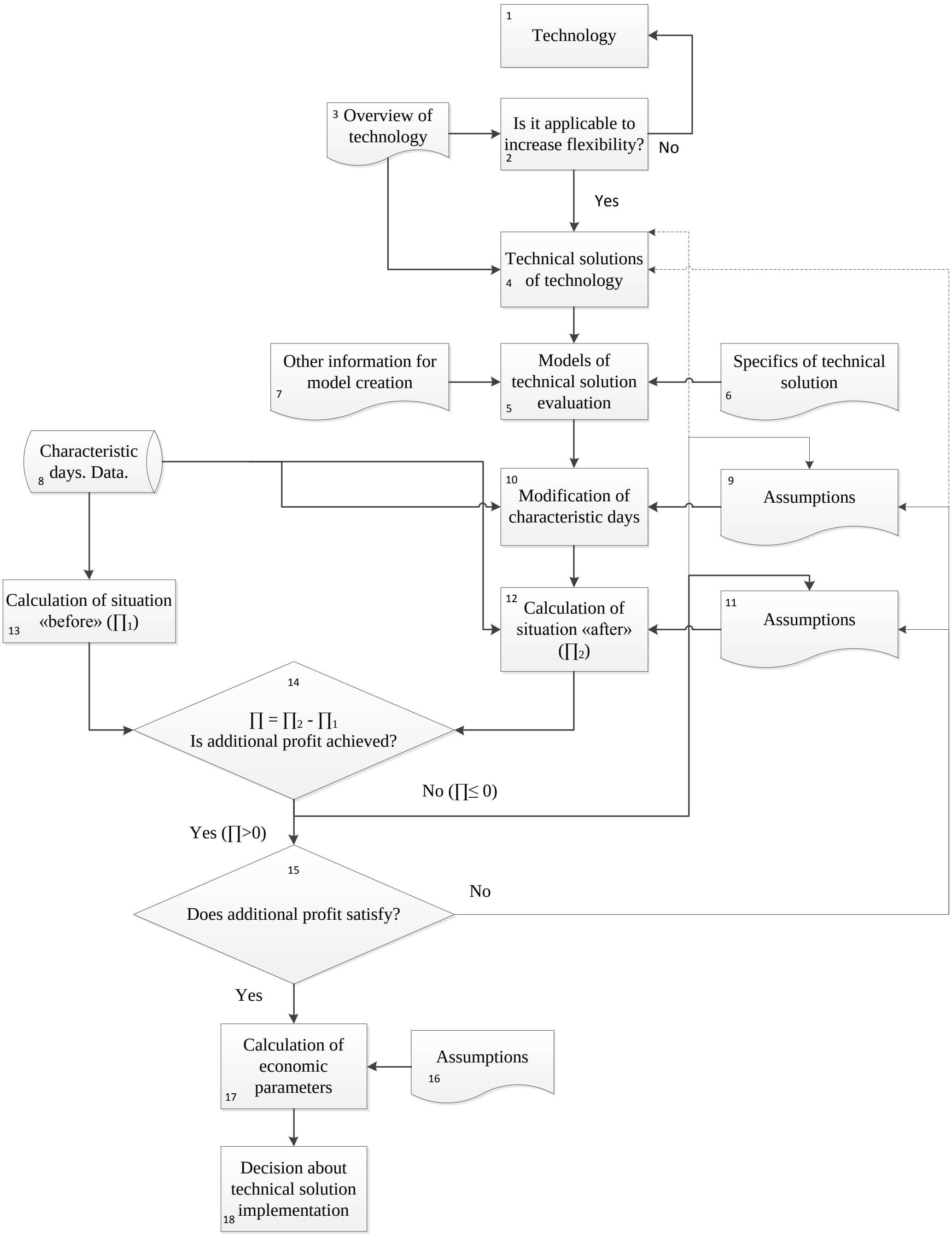


Fig. 5.1. General algorithm for technical and economic evaluation of technologies.

According to the developed algorithm (Fig. 5.1), the technology should be selected (1), which is intended to increase the power plant flexibility and, as a result, to produce additional profit. After the literature review (3) of the selected technology, the decision is made about its capability to increase the flexibility level of thermal power plant (2). If the answer is positive (Yes), technical solutions of the technology are determined and their overview is provided to obtain necessary information for future evaluation (4). If the answer is negative (No), a new technology is selected. Then, the model of the technical solution is developed (5) in pursuance of its determined application. The specifics of the technical solution (6) and other information (7) are taken into account (Fig. 5.1).

The characteristic days (present power plant operation) are chosen (8) to evaluate the technical solution. Moreover, the information about a thermal power plant and characteristic days is collected (data), for example, heat and electrical power, electricity price, ambient air temperature. The assumptions (9) are used to create the modification of characteristic days (10). Modified days present the situation "after", i.e., when the technical solution is integrated in the generation portfolio of a thermal power plant (Fig. 5.1).

Taken into account assumptions (11), modified days (10) and data (8), the situation "after" is calculated (12), i.e., the profit of a power plant is determined, when the technical solution is implemented. To make the decision about the amount of additional profit achieved (14), the situation "before" is calculated (13), when a power plant operates without the technical solution, using the data of characteristic days (8). When the both vales (Π_1 and Π_2) are known, the additional profit is calculated as the difference between $\prod_2$ and $\prod_1$ (14). If it is negative or equal to zero, then the changes in assumptions (9), (11) should be made or the other technical solution of technology should be taken for evaluation purposes (4). Otherwise, a new technology should be selected. If the obtained profit is more than zero, then its quantity is estimated. If the amount of the obtained additional profit does not satisfy, the changes in assumptions (9), (11) should be made or other technical solution should be taken (4). Otherwise, a new technology should be selected. If it is satisfactory, the economic parameters are calculated taking into account assumptions (16). Next the decision is made about the implementation of the technical solution (18) (Fig. 5.1).

The developed algorithm also evaluates the technology or its technical solutions under different conditions (a sensitivity analysis). Different scenarios can be checked, for example, the changes in the number of typical days, in the characteristics of the technical solution, in the assumptions (flue, electricity, CO_2 price, etc.).

Within the framework of the Thesis, the developed algorithm is adapted to three different technologies: air cooling, electric boiler and heat storage system. As a result, three methodologies have been created. They are described in detail in Chapters 6, 7 and 8, respectively. In turn, Table 5.1 provides a general overview of the main algorithm steps concerning the estimation of certain technologies.

Table 5.1

An Overview of the Adaption of the Main Algorithm Steps to Different Technologies*

	Air cooling	**Electric boiler**	**Heat storage system****
Application of technology (how it is used to increase the flexibility level of a power plant)	Adjustment to the fluctuations of the electricity price in the market. More electricity production in periods of high electricity prices.	Natural gas HOB and biomass boiler substitution with an electric boiler (EB) to decrease production costs and increase competitiveness of a fossil fuel thermal power plant.	Decoupling of electrical and heat production. Adjustment to the fluctuations of the electricity price in the market. Production increases in periods of high electricity price and its reduction is observed in periods of low electricity price.
Technical solutions of technology	Mechanical chiller. Absorption chiller. Evaporative type chiller. Fogging type chiller.	A certain technical solution is not chosen. Technology is completely considered.	Based on the foreign and local experience, the thermal energy system with the liquefied storage medium (water), thermal energy displacement (ensuring of stratification) and vertical heat storage tank position is chosen.
Models of technical solution evaluation. Specifics of technical solutions. Other information.	Gas turbine model and its characteristics. Characteristics of technical solutions. Constraints, which limit the use of technical solutions. Information about gas turbine parameters and climatic conditions, technical solution parameters.	Model to calculate the substitution of the natural gas HOBs and biomass boilers with EB. Specifics of EB. Information about the structure of heat energy price and efficiency of the natural gas HOB and biomass boiler.	Model integrates the heat storage system in the generation portfolio of a power plant. Information about power plant characteristics.
Characteristic days. Data.	Choice of characteristic days and their number. Hourly data about gas turbine power, ambient air temperature and electricity price. Data about price of fuel and CO_2 emissions.	The days are chosen where the substitution of natural gas HOB and biomass boiler can be economically justified. Hourly data about electricity price, heat power. Data about natural gas and biomass price.	Characteristic days and their number are identified. Hourly data about heat and electrical power, equipment content and electricity price. Data about price of fuel and CO_2 emissions.
Modification of characteristic days. Assumptions.	Changes in the generation profile. Additional electrical power production, when air cooling technology is used.	Changes in natural gas HOB and biomass boiler generation portfolio, when EB is used. Assumptions about EB power and its operation periods.	Changes in the production profile. Assumptions about the heat storage tank capacity and operation patterns of a power plant.
Calculation of situation "before".	The hourly amount of produced power is determined.	Calculation of HOB power and its production costs.	Power plant profit calculation without the operation of the heat storage system.

Calculation of situation “after”. Assumptions.	The change of power production is calculated. Additional income is determined.	Power of natural gas HOB and biomass boiler after EB implementation. Production costs of an electric boiler. Income calculation after the substitution of HOB and biomass boiler with EB.	Power plant profit calculation after heat storage system implementation. Assumption about the influence of technical solution implementation on the electricity price in the market.
Decision about the technology	The change of benefit magnitude is checked implying the sensitivity analysis	The calculated income persuades to determine the pay back ratio to judge tentatively about the expedience of natural gas and biomass boiler substitution with electric boiler.	The economic parameters are determined to decide about the feasibility of heat storage system implementation. The sensitivity analysis is also provided to different price scenarios.

**The general information is presented in Table 5.1. For more details see Chapters 6, 7, 8.*

***A lot of work has been done by the author concerning heat storage system (see [4], [15], [17], [74]–[79]). That is why in the Thesis the updates of the previously provided work are presented (see Chapter 8).*

The adapted algorithm for three different technologies is approbated on the example of Riga TPP–2 plant and the Latvian site climatic conditions (see Chapters 6, 7, 8). Conclusions about their application are presented in Chapters 6, 7, 8.

The algorithm has practical application. It has been adapted to evaluate the feasibility of installation of the exhaust gas condenser economizer at Riga TPP–1 (HOB No. 3) and gas turbine modernisation at Riga TPP–2. Both installation of the exhaust gas condenser economizer and modernisation of the gas turbine have been implemented. For more details see the author’s works [80] and [4], [15], respectively. The algorithm has been used to evaluate the feasibility of heat storage system installation at Riga TPP–2. The co-financing was assigned within the framework of programme “Development and Employment” (the second call of 4.3.1. Specific Support Object measure “Promote energy efficiency and the use of local renewable energy sources in district heating system”) [81]. Now the procurement procedure is conducted to select EPC contractor for the development of technical design and for further construction of the heat storage tank [82].

6 USE OF AIR COOLING TECHNOLOGY

6.1. Justification and Technical Solutions of Technology

The elimination of gas turbine disadvantage (its performance dependence on ambient conditions [83]) by means of air cooling at the input of compressor of GT can be used to meet electricity market challenges. In accordance with [84]–[89], the most significant impact on gas turbine operation is provided by ambient air temperature. The power output of gas turbine is directly proportional to ambient air temperature [88]. Therefore, with the increase of air temperature the power output and thermal efficiency of gas turbine decrease and heat rate increases. This is explained by the fact that the volumetric flow rate of air entering a gas turbine unit is constant. The density of air decreases with the increase of its temperature. It results in the decrease of the mass flow [88]. This negative aspect of gas turbine can be mitigated with the help of air cooling at the input of compressor of GT unit. When the electricity price is high, the implementation of air chilling during the daytime ensures the growth of profit while selling surplus of electricity on the market. The profit can be optimised combining the air cooling with ice thermal energy storage, chilled water thermal energy storage or low temperature stratified fluid thermal energy storage [90].

Moreover, air cooling provides other benefits, such as [91] 1) the increase of fuel efficiency; 2) the extension of lifetime of gas turbine parts; 3) the improvement of combined cycle efficiency; 4) the delay of power plant extension; 5) the increase of system efficiency, when it operates at base load; 6) the absence of necessity to spray water and steam; 7) the forecasting of energy production.

The following aspects can be considered the disadvantages of air chilling [91]: 1) the loss of air pressure in air flow duct; 2) some additional space is required for the installation of chiller.

Traditionally, there are four air cooling technologies: absorption chiller, mechanical chiller, evaporative and fogging cooling [85]. In addition, there are also other solutions [83], [92]: 1) a liquefied vaporization system; 2) hybrid systems; 3) efficient use of cooling capacity in the gas refinery pressure drop station. The choice of technology is determined by the climatic conditions of region and the results of economic analysis.

Many researchers provided technical reviews and comparison of air chilling technologies [86]–[88], [90], [93]–[96]. According to these sources of information, the main distinctive features of traditional air chilling technologies are the following:

- The fogging (FC) and evaporative (EC) types of air cooling are the best solutions for hot and dry climate. In turn mechanical and absorption chillers are used in the regions, where climatic conditions are warm and humid;
- The mechanical (MC) and absorption (AC) chillers are not sensitive to ambient air of wet bulb-temperature, while surplus power gain in the case of evaporative and fogging cooling is limited by ambient air of wet bulb-temperature;
- The mechanical and absorption chillers chill down the air until 7 ^{o}C –13 ^{o}C, meanwhile the evaporating and fogging cooling – until 5 ^{o}C –8 ^{o}C;

- The absorption and mechanical chillers ensure greater power output up to 20 % and up to 15 %, respectively, than that of the evaporative and fogging cooling, i.e., 5 %–10 %;
- The mechanical and absorption chillers have high operation and maintenance (O&M) costs, while fogging and evaporative cooling have low O&M costs;
- The evaporative and fogging cooling is the cheapest technical solutions. The absorption chiller is the most expensive solution: installation costs account for approximately 273 €/kW–637 €/kW additionally. The installation costs of the mechanical chiller are about 182 €/kW–454 €/kW. The evaporative (23 €/kW–45 €/kW) and fogging cooling (41 €/kW–64 €/kW) are the cheapest air cooling solutions;
- The fogging and evaporative cooling as well as absorption chillers have low parasitic load, for instance, in the case of evaporative cooling it is 0.5 % of surplus electricity. Mechanical chillers have the highest parasitic load of up to 30 % of the additionally produced electricity.

The air cooling systems are mainly installed in the regions with hot and dry climate, such as Iran [84], Iraq [97], Oman [93], Saudi Arabia [90], Brazil [85] etc., with the aim to increase the production of electricity and cover the peak demand of electricity during the periods of high air temperature, thus avoiding power plant extension. Within the framework of the Thesis, the use of air cooling technologies is considered in wet and warm climate conditions to adapt a CCGT power plant to a situation in the electricity market, increase the production of electricity and receive additional income from additionally produced electricity realisation in the market.

6.2. Methodology of Air Cooling Evaluation

The algorithm (Fig. 6.1) is used to evaluate the use of air chilling technologies at TPP to adapt their operation to a variable situation in the electricity market. The fundamentals of the algorithm: the yearly profit is calculated by multiplying a characteristic day with its number in a year. The difference between two situations (*after* air cooling and *before* air chilling) determines the profit of a characteristic day. The information about a characteristic day (ambient air temperature and electricity price) and gas turbine characteristics (results of simulation) are used as input data. The algorithm contains constraints, which limit the use of air cooling technologies.

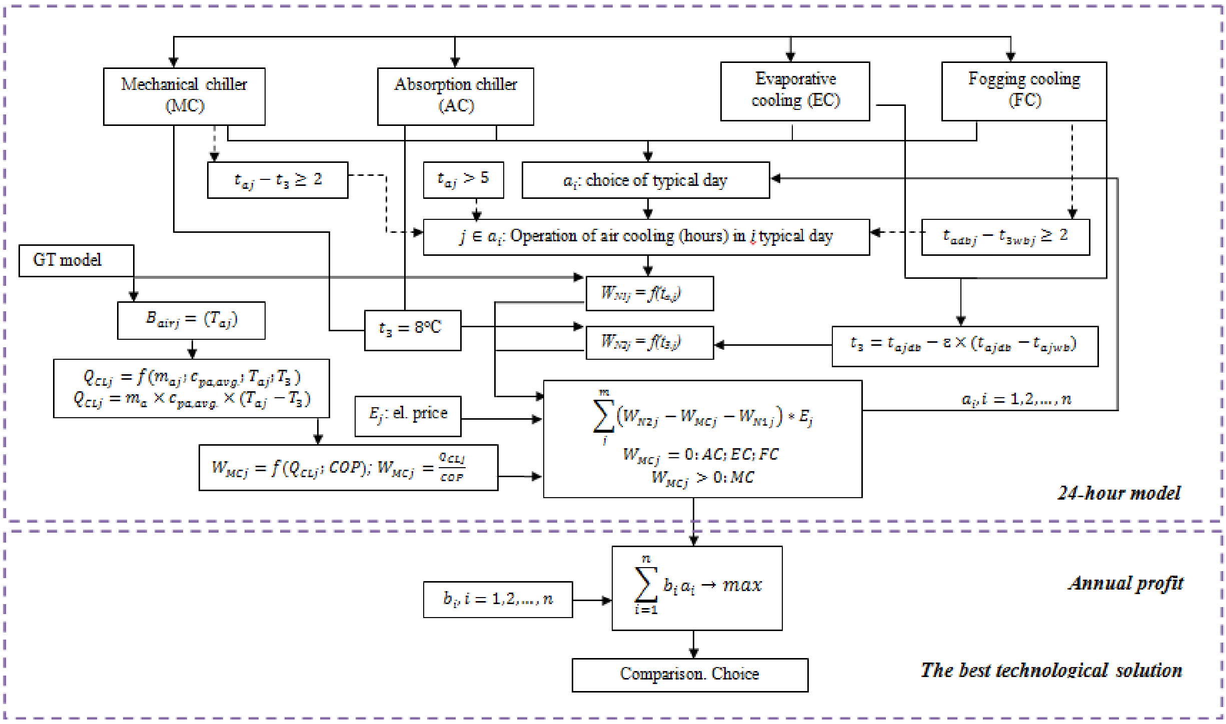


Fig. 6.1. Evaluation algorithm [98].

The objective function ensures the maximisation of benefit (P_y) gained by chilling the air in front of the compressor of GT unit:

$$P_y = \sum_{i=1}^{n} b_i \times a_i = \sum_{i=1}^{n} b_i \times \left(\sum_{j=1}^{m}((W_{N2} - W_{N1} - W_{MC}) \times E)_j\right) \rightarrow max\,, \tag{6.1}$$

where P_y – profit from air cooling per year, €/year;

b – the number of typical days within a year, number/year;

a – profit of a typical day in 24 h, €/24h;

i, n – the order number of a typical day within a year, [-];

j, m – the order number of hours in a typical day, [-];

E – electricity price, €/MWh;

W_{N2} – power after air cooling, MW/h;

W_{N1} – power before air cooling, MW/h;

W_{MC} – the parasitic load of mechanical chiller, MW/h.

If cool energy is produced at night for the later use, i.e., during the daytime (energy storage), the objective function is the following:

$$P_y = \sum_{i=1}^{n} b_i \times \left(\sum_{j=1}^{m}((W_{N2} - W_{N1}) \times E_d - (W_{MC} \times E_n))_j\right)_i \rightarrow max. \tag{6.2}$$

The parasitic load is multiplied by the electricity price during the night time (E_n) and the additionally produced electricity – by the electricity price during the daytime (E_d) [84].

The information about typical days (electricity price and ambient air temperature) and characteristic of gas turbine (result of simulation) are used as input data.

The algorithm contains constraints, which limit the use of air cooling technologies [88]:

- The minimum temperature at the input of compressor should be 5 ^{o}C–8 ^{o}C to prevent the icing of compressor. When the air enters the compressor, the velocity of air increases and temperature decreases because the enthalpy of air is transforming into kinetic energy. The temperature drop is ~ 5 ^{o}C due to this process;

- The operation of absorption and compressor chillers is stopped, if the difference between the air temperature at the input and at the output of air cooling technology is less than 2 ^{o}C;
- The operation of fogging and evaporative chillers is stopped, if the temperature difference between wet (t_{wb}) and dry (t_{db}) thermometer is less than 2 ^{o}C.

The equations used in the algorithm determine the air temperature at the output of evaporative and fogging cooling (t_3) and the cooling load (Q_{CL}) and parasitic power (W_{MC}) of mechanical chiller. They are based on [84], [88], and [99] respectively.

The gas turbine manufacturers provide the characteristics (power output, heat rate, efficiency) of gas turbines under ISO conditions (ISO: 3977–2): ambient air temperature is + 15 ^{o}C; relative humidity is 60 % and pressure is 101.3 kPa [83]. The thermodynamic model of gas turbine is used to obtain the information about GT values within the range of ambient air temperature from + 5 ^{o}C to + 31 ^{o}C. The mathematical description of the GT thermodynamic model presented below is based on [85], [88], [89], [100], [101]. The schematic illustration of gas turbine unit with necessary points, used in the GT mathematical model, is reflected in Fig. 6.2.

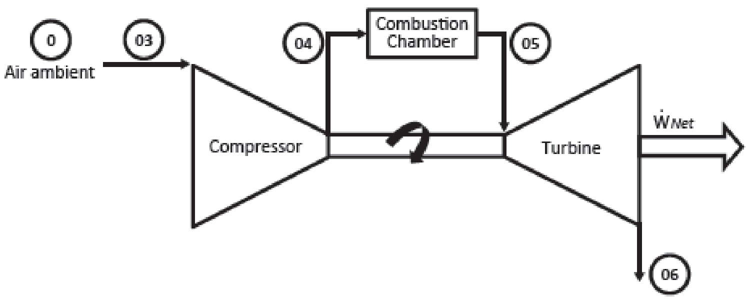


Fig. 6.2. Gas turbine unit (0, 03, 04, 05, 06 refer to a lower index in the equations below) [85].

The pressure of air at the output of compressor:

$$P_{04} = \beta \times P_{03}, \tag{6.3}$$

where β – compression ratio, [-].

The temperature of air at the output of compressor

$$T_{04} = \frac{T_{03}}{\eta_c} * \left(\left(\frac{P_{04}}{P_{03}}\right)^{\frac{k-1}{k}} - 1\right) + T_3, \tag{6.4}$$

where η_c – isentropic efficiency of the compressor, [-];

T_{03} – air temperature at the input of compressor, K.

The work performed by the compressor is expressed using the first thermodynamic law:

$$W_c = m_a \times c_{pa,avg} \times (T_{04} - T_{03}), \tag{6.5}$$

where m_a – air mass flow, kg/s;

$c_{pa,avg}$ – average specific heat of air, kJ/(kg×K).

The pressure at the output of combustion chamber:

$$P_{05} = P_{04} - \Delta P_{combustor}, \tag{6.6}$$

where $\Delta P_{combustor}$ – combustion chamber pressure loss, Pa.

Heat delivered by the combustion chamber:

$$W_c = m_a \times c_{pa,avg} \times (T_{04} - T_{03}), \tag{6.7}$$

where T_{05} – temperature at the input of gas turbine, K;

$c_{pg,avg}$ – average specific heat of flue gas, kJ/kg×K.

The mass flow of natural gas:

$$m_f = \frac{\frac{Q_{in}}{LHV}}{\eta_{combustor}}, \tag{6.8}$$

where *LHV* – a lower heat value of natural gas, kJ/kg;

$\eta_{combustor}$ – combustion efficiency, [-].

The temperature of flue gas at the output of gas turbine:

$$T_{06} = T_{05} + \eta_t \times T_{05}\left(\frac{1}{\left(\frac{P_{05}}{P_{06}}\right)^{\frac{k-1}{k}}} - 1\right), \tag{6.9}$$

where η_t – isentropic efficiency of the turbine, [-];

P_{06} – pressure at the output of gas turbine, Pa.

The power of the gas turbine:

$$W_t = m_T \times c_{pg,avg} \times (T_{05} - T_{06}), \tag{6.10}$$

where m_T – the mass flow of mixture (air and natural gas), kg/s.

The net power of the gas turbine:

$$W_N = W_t - W_c. \tag{6.11}$$

Specific fuel consumption:

$$SFC = \frac{3600 \times m_f}{W_N}, \tag{6.12}$$

where m_f – natural gas mass flow, kg/s.

Heat rate:

$$HR = SFC \times LHV. \tag{6.13}$$

The thermal efficiency of the gas turbine:

$$\eta_{th} = \frac{3600}{SCF \times LHV}. \tag{6.14}$$

The calculation is made for 9F.05 General Electric gas turbine model. The ISO conditions of this GT in simple cycle: power output is 299 MW, heat rate is 9295 kJ/kWh, and net efficiency is 38.7 % [102]. The used input data and assumptions are summarised in Table 6.1.

Table 6.1

Input Data and Assumptions [98], [103]

Parameter	**Value**	**Unit**
Pressure at the input of compressor	101 325	Pa
Compression ratio	18.3	-
Average specific heat of air	1.40	-
Average specific heat of flue gases	1.33	-
Temperature at the input of gas turbine	1380	^{o}C
Lower heat value of natural gas	50 044	kJ/kg
Air mass flow	653	kg/s
Isentropic efficiency of compressor	85.0	%
Isentropic efficiency of turbine	85.5	%
Combustion efficiency	99	%
Combustion chamber pressure loss	1.17	%
Fuel	Natural gas	-
Average specific heat of air	1.046	kJ/kg×K
Average specific heat of flue gas	1.230	kJ/kg×K
Pressure at the output of gas turbine	104 460	Pa

According to Fig. 6.3, the decrease of net gas turbine power is ~ 11.1 %, when the ambient air temperature increases from + 15 ^{o}C to + 31 ^{o}C. In turn, the heat rate increments by ~ 1.7 % and thermal efficiency decrements by ~ 1.6 %.

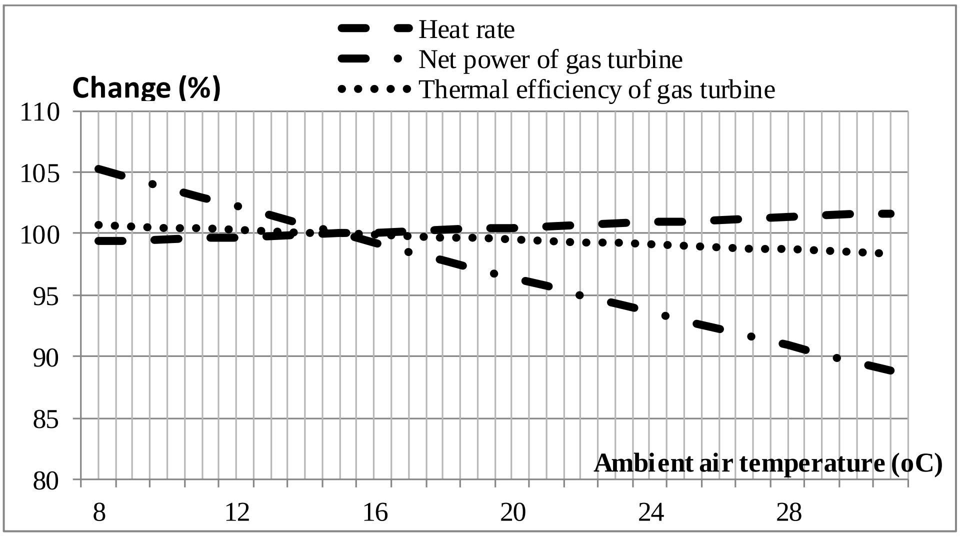


Fig. 6.3. The influence of ambient air temperature on 9F.05 GT unit performance [98].

In addition, the necessary characteristic is obtained to determine the economic benefit of the air chilling technologies. They are

$$W_N = 2.0873 * t_a + 322.89, \tag{6.15}$$

$$m_a = 0.0053 * {t_a}^2 - 2,5076 * t_a + 689.81. \tag{6.16}$$

6.3. Practical Application of the Methodology

Figure 6.4 provides the example of CCGT-2/2 unit operation during the summer period in 2015. The cogeneration unit is at full load during the daytime, when electricity price is high at electricity power exchange. The dashed line reflects the range when air chilling can be used to generate additional electricity. It is during the daytime, when GT is at full load and the electricity price is high. The profit of air chilling is obtained from selling additionally produced electricity to the market.

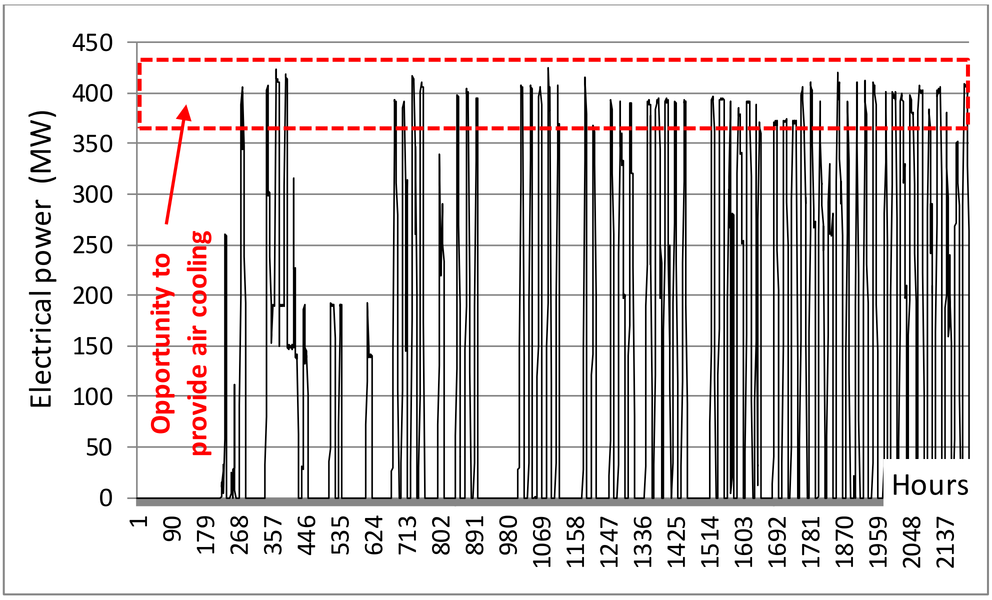


Fig. 6.4. Example of CCGT–2/2 unit operation in summer (June–August) in 2015 [98].

Latvia is located on the seacoast of the Baltic Sea in the zone of moderate climate. Considering the data in [104], the climatic conditions of Riga were analysed from 2000 to 2015. The level of relative humidity is high during the whole year. The highest value is observed in winter ~ 89 %. The average maximum temperature is + 18.5 °C. In general, the climate is warm and humid in Riga (Fig. 6.5).

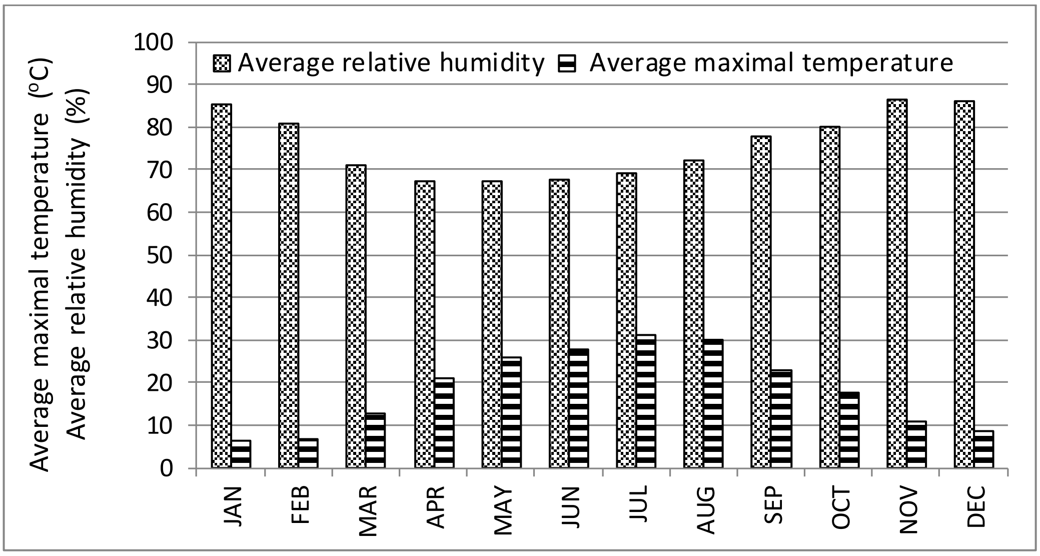


Fig. 6.5. Results of analysis of Riga climatic conditions from 2000 to 2015 [98].

The benefit from air cooling during a year is calculated by choosing one typical day from the reflected period in Fig. 6.4 and multiplying by the accepted number of these days in a year, i.e., 49 days. The necessary data (electricity price, ambient air temperature, power, etc.) for calculation are taken according to a typical day. According to the obtained results (Fig. 6.6), the mechanical and absorption chillers are more appropriate for the climate conditions in Riga than other technologies (Fig. 6.6). The benefit of mechanical and absorption chillers exceeds the profit of evaporative cooling ~ 4 times and fogging cooling ~ 2–3 times.

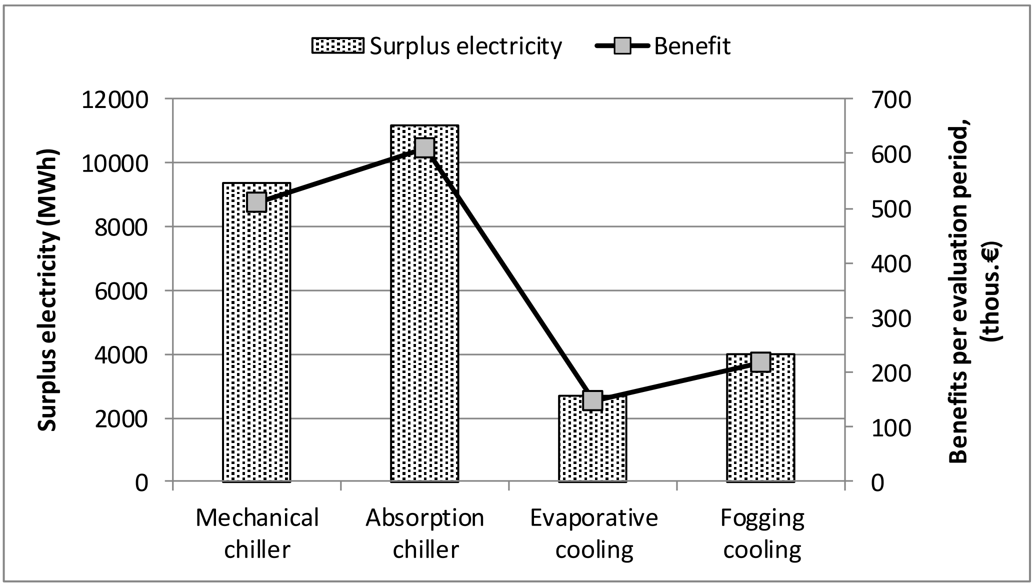


Fig. 6.6. Additional electricity and benefits of different air cooling technologies [98].

The benefit from air cooling (P_y) can be represented as a function (6.17) of ambient air temperature (t); electricity hourly price (E); number of operated days during a year (n) and operated hours during a typical day (m). In the case of a mechanical chiller, such parameter as coefficient of performance (COP) should be mentioned.

$$P_y = f(t; E; n; m; COP). \tag{6.17}$$

The ambient air temperature is taken into account if the calculation of benefit is carried out for different regions.

The sensitivity analysis is carried out for mechanical and absorption chillers as the more appropriate technologies for the climate conditions in Riga (Latvia) (Table 6.2).

Table 6.2

Results of Sensitivity Analysis [98]

	Mechanical chiller (COP = 2)		Absorption chiller	
	MWh	thous. €	MWh	thous. €
Additionally gained income	($E_{avg.}$ = 54.5 €/MWh; n = 49 days; m = 10 hours/day)			
	9376	511.41	11172	609.81
E decrease by 36 %	($E_{avg.}$ = 34.9 €/MWh; n = 49 days; m = 10 hours/day)			
	9376	327.32	11179	390.27
E increase by 18 %	($E_{avg.}$ = 64.4 €/MWh; n = 49 days; m = 10 hours/day)			
	9376	603.49	11179	719.56
n increase by 85 %	($E_{avg.}$ = 54.5 €/MWh; n = 91 days; m = 10 hours/day)			
	17381	949.77	20748	1132.50
m decrease by 50 %	($E_{avg.}$ = 54.5 €/MWh; n = 49 days; m = 5 hours/day)			
	4813	263.24	5737.78	313.84
COP = 4	($E_{avg.}$ = 54.5 €/MWh; n = 49 days; m = 10 hours/day)			
	10277	560.62	-	-

The decrease in the electricity price (E) and operating hours (m) during the day exerts the most negative impact on the additionally gained income. It is the decrement of income by 56 % and 48 %, respectively. The increase in operating days (n) ensures the most positive influence on the additionally gained income. It is the increment by 85 %.

6.4. Summary

1) The air cooling technology, apart from the elimination of negative impact of ambient conditions on gas turbine performance, can be used to meet market challenges and enhance the flexibility of a thermal power plant by following the fluctuation of the electricity price in a more money-making way.
2) The evaluation methodology is approbated on the example of Latvian site conditions and Riga TPP–2 operation patterns. Mechanical chiller and absorption chillers are the most appropriate air cooling technologies.
3) The additionally gained income from air cooling implementation is a function of ambient air temperature, electricity hourly price, coefficient of performance, number of operation days during a year and operated hours during a typical day. The decrease in the electricity price and operating hours during the day provides the most negative impact on the gained income. In turn, the increase in operating days ensures the most positive influence on it.

4) The production of additional electricity simultaneously ensures the improvement of power plants efficiency, i.e., less fuel is consumed to generate more electricity. This fact should be taken into consideration, supported and financed by the government because this corresponds to the aim of the European Commission, i.e., the promotion of efficiency.

7 INSTALLATION OF ELECTRIC BOILER

7.1. Justification and Technical Solutions of Technology

Traditionally, TPPs are used to provide the heat to the district heating systems (DHS). Today they are already integrated with power generation in the electrical power system (EPS) since TPPs are used for heat supply [105]. This creates new opportunities and conditions for district heating (DH) and power system cooperation through the use of DH flexible technologies, i.e., power-to-heat (P2H) technologies (electric boilers (EB) and heat pumps).

According to [106]–[109], there are obstacles to use P2H technologies in district heating. A significant obstacle to the usage of these technologies related to the additional use of electricity is the existing legislation supporting a payment system that produces prices from several components that include, apart from market prices, also a fee for network services and taxes. This leads to the increase in thermal energy price making P2H technologies impossible to compete with tax-free HOBs (natural gas or biomass). For example, in Latvia the electricity price composes only 30 % of electricity tariff, 70 % is payment for transmission and distribution system services, payment for mandatory procurement and capacity components and value-added tax [110]. Hence, the operation of P2H technologies is economically cost-efficient at a very low electricity price (Fig. 7.1).

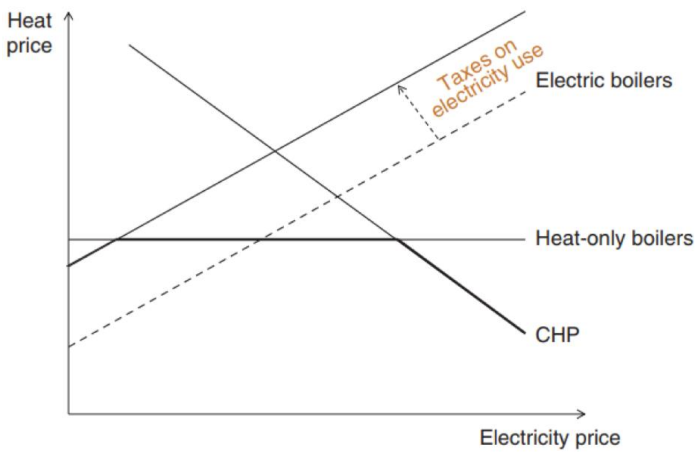


Fig. 7.1. Effect of taxes on the heat costs with different electricity prices [107].

However, in line with [108], [106], the use of P2H facilities in DH system is cost-effective, when these technologies provide the ancillary services. Thus, the use of district heating flexible technologies is mainly widespread in regions with high share of intermitted generation, where there is the necessity of ancillary services (the utilisation of surplus electricity from variable generation into the heat energy with its further injection in the district heating system) and the use of P2H technologies is economically justified [17], [74], [111]–[113].

Within the framework of the Thesis, the use of P2H technologies (electric boiler) is considered in countries with a low share of intermittent generation, but with a high share of biomass, where the operation of thermal power plants is influenced by the situation in the electricity market and the operation in a highly competitive environment. Moreover, it is assumed that the production costs of an electric boiler are equal to the electricity price (the other components of electricity tariff are omitted) in the market. The author would like to demonstrate that the district heating technologies, which facilitate the interaction between electricity and heat production, can be widespread not only in the ancillary market, but can also provide the competitive heat energy and reduce the production costs of a thermal power plant.

Heat pump and electric boiler are known as P2H technologies. They use electricity to produce heat whenever it is possible [114]. The electric boiler is going to be considered, but a heat pump is omitted due to the following reasons:

- Electric boiler is more flexible than a heat pump. The latter has a lead time from start until the optimal efficiency is reached (Fig. 7.2) [107], [111] and [115];
- Moreover, heat pumps are more expensive than electric boilers. Due to large investment costs, they are mainly used as base loads [115], [107].

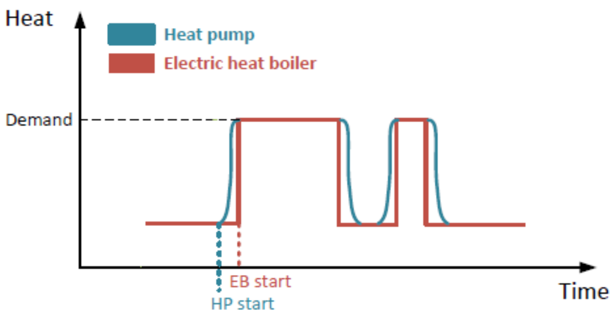


Fig. 7.2. Ramping principles of heat pump and electric boiler [111].

The electric boiler is the most compact and cost efficient transformation of power into heat (hot water or steam). The main applications of electric boiler are [116], [117]: 1) the regulation of electric grid parameters; 2) decoupling of electricity and heat production; 3) the substitution of the equipment, which is not economically profitable; 4) ensuring of the safety of energy supply.

Different technological solutions of EBs can be used. There are two types of electric boilers: with electric heater (electric resistance boilers) and electrodes. The latter is divided into immersion-type (immersed electrodes to conduct electricity through the water) and jet/spray (rely on water jets striking an electrode plate). By product, there are water or steam electric boilers [118]–[120]. The electrode boilers operate under high voltage (4–24 kV) and their load is up to 70 MW. Meanwhile, the electric resistance boilers mainly operate under low voltage (< 700 V) and their load is up to 4 MW [120]–[122]. To achieve high installed capacity of electric boilers, more than one boiler should be installed. The investments and operation costs of electric boilers are low [111], [112], [119], [121].

The comparison of EB with natural gas and biomass HOBs is presented in Table 7.1. The electric boilers are more efficient, environmentally-friendly and flexible than heat only boilers [111], [120], [121], [123].

Table 7.1

Comparison of Gas and Electric Boilers [111], [120], [122], [123]

Parameter	Unit	Gas boilers	Biomass boiler	Electric boilers
Efficiency	%	$\eta^{HOB} = 92$	$\eta^{BIO} = 89$	η^{EB} ~ 99–100 %
Start-up time	hours	< 1	~ 2	< 0.00028 (or < 30s)
Production costs per time unit, i	-	$P_i^{Q,HOB} = f(P_m^{NG}; P_i^{CO2}; \eta^{HOB}_{avg})$	$P_i^{Q,BIO} = f(P_m^{BIO}; \eta^{BIO}_{avg};$ *characteristics of biomass)*	$P_i^{Q,EB} = f(P_i^E)$, assumed $\eta^{EB} = 100\%$, then $P_i^{Q,EB} = P_i^E$
Environmental aspect (the most relevant emissions)	-	CO_2, CO, NO_x,	PM, NO_x	-
Investments	M€/MW	0.07–0.13	~ 0.603	0.13–0.16 (low voltage; load 1–3 MW)
				0.06–0.09 (high voltage; load 10 MW)
				0.05–0.07 (high voltage; load 20 MW)

Analysing the information in Table 7.1, the following valuable characteristics of electric boiler can be distinguished: 1) high operation efficiency; 2) electricity is used as fuel, no fuel or feeding systems or stack; 3) fast start-up; 4) easy to regulate: the increase/decrease of load in a few seconds; 5) extremely dependable and easy to maintain.

7.2. Evaluation Methodology of Electric Boiler

District heating can be provided by the energy production system, which is manageable and include some technologies [124], for example, TPP, EB, gas faired boiler (GFB) and biomass boiler (BB). Equipment can belong to different owners and can generate at hour i amount of energy: 1) TPP – electricity (P_{TPPi}) and heat (Q_{TPPi}); 2) GFB – Q_{GFBi}; 3) BB – Q_{BBi}. The produced energy is manageable and hourly produced energy can be considered optimisation parameters (X_{1i}, $X_{2i}, \ldots$). Energy generated at hour i can be sold and ensure a profit, respectively: Pr_{1i}, Pr_{2i}, Pr_{ni}. Profit is influenced by the electricity market price, thermal energy price, gas price, biomass fuel price, heat energy demand and ambient air temperature. All these time dependent processes can be marked C_i. The models must be created that provide the ability to calculate profits for specified input processes and optimisation parameters. As a result, when hourly profits Pr_{1i}, Pr_{2i}, Pr_{ni} are estimated, the annual profit Pr_{1y}, Pr_{2y}, Pr_{ny} can be described:

$$\mathrm{Pr}_{1y} = \sum \mathrm{Pr}_{1i} = F_1(X_{1,1},\ldots,X_{1,8760}; X_{2,1},\ldots,X_{2,8760},\ldots,C_1,\ldots,C_{8760}), \quad (7.1)$$

$$\mathrm{Pr}_{ny} = \sum \mathrm{Pr}_{ni} = F_1(X_{1,1},\ldots,X_{1,8760}; X_{2,1},\ldots,X_{2,8760},\ldots,C_1,\ldots,C_{8760}), \quad (7.2)$$

where $X_1 \ldots X_{8760}$ must be considered optimisation parameters. Annual profits $Pr_{1y}, Pr_{2y}, \ldots, Pr_{ny}$ can be used as optimisation criteria (objective function).

Unfortunately, the direct use of Eqs. (7.1) and (7.2) for the solution of the problem under consideration is impossible, since in the general case it is impossible to reach a maximum of several functions simultaneously. In addition, the optimisation problem is extremely complicated since it is stochastic, nonlinear, contains a huge number of optimisation parameters, and multicriterial. To simplify the stated problem, additionally, it is accepted:

1. Affecting processes C_i are forecast using one point prediction. The problem turns into a class of deterministic.
2. The cost and time of the change in the power of the generated energy can be neglected. In this case, we can state that the profit of the current day does not depend on the state of the generators in the previous period and solve the optimisation task hour by hour, determining the values of the generated capacities for each hour of the year. The problem of optimisation is simplified radically. A complex problem of Eqs. (7.1) and (7.2) is divided into many simpler ones:

$$\Pr_{si} = F(X_{1,i}, X_{2,i,\ldots,C_i}) \to \max . \tag{7.3}$$

In this case, only one hour prediction is used for the estimation of profitability and hourly optimisation parameters.

3. Energy production system under consideration is running in the electricity and heat energy markets. Electricity prices can be predicted and are exogenous. Thermal energy prices are limited by a regulator. Furthermore, it is assumed that each thermal energy producer is a player in the heat energy market. The market price is formed hourly by choosing the cheapest offers. In addition, it is believed that each player forms his own market offer seeking to avoid losses (negative profit) even in the occurrence of an unsuccessful situation. This circumstance facilitates decision-making when selecting the composition of the technologies used. The problem of maximising profits is replaced by a simpler task of finding the minimum price at which profit is positive. For this purpose, it is sufficient to solve the equation:

$$\Pr_{si} = F(X_{1i,} C_i) \geq 0 . \tag{7.4}$$

It is assumed that the maximum power of each technology under consideration is used.

Having solved the equations for all technologies, the thermal energy supply-demand curve can be constructed and the demand can be predicted for it in order to find the equilibrium point, which determines the market price (Fig. 7.3).

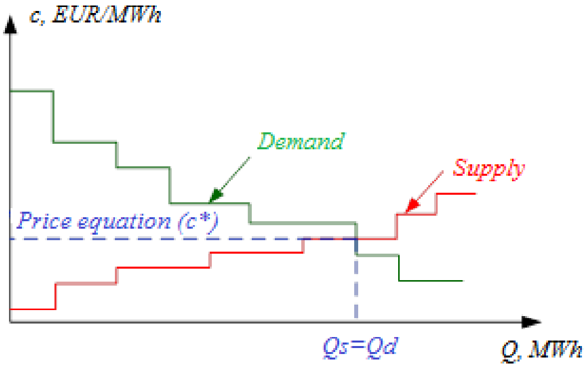


Fig. 7.3. Thermal energy price formation mechanisms (Q_s – thermal energy supply, Q_d – thermal energy demand, c – price of thermal energy, Q – thermal energy).

Simultaneously, the energy of each technology is determined (the total power of low-priced and the power of the most expensive source necessary for the equilibrium between the generated and consumed energy). This is sufficient to assess the profits of each technology. The structure of yearly profit calculation algorithm is depicted in Fig. 7.4. It is the general algorithm for two *targets* considered below. The hourly production data (hourly thermal load) and additional information (prices of natural gas, electricity and biomass; calorific value of natural gas; efficiency of technology; price of CO_2 and its emissions factor for natural gas) are used as input data to develop the calculation platform, i.e., the thermal power of heat energy sources is determined. Then the hourly income is calculated. If it is negative, the income is equal to zero and the next hour is chosen for evaluation. If the hourly calculated income is positive, it is stored for further yearly income calculation while the other hours are checked.

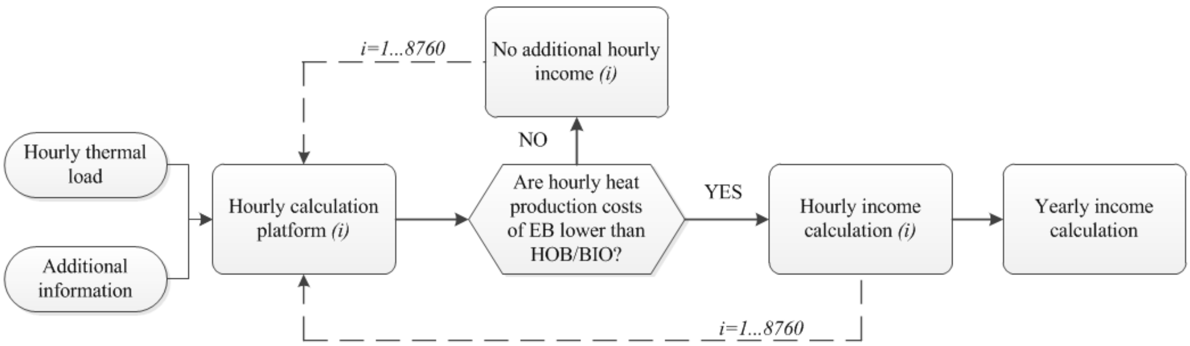


Fig. 7.4. The algorithm of income calculation [125].

The use of electric boiler is evaluated for the following *targets* [59], [125]:

1. *Target No. 1:* During the night, the marginal costs of a cogeneration unit (CU) are higher than the electricity price in the market. Thus, HOBs are used instead of CU, whose operation can be substituted with EB in a more profitable way to reduce the productions costs of TPP power plant.
2. *Target No. 2:* The appearance of new heat energy sources, such as biomass HOBs (BIO), can offer a lower heat energy price than a fossil fuel TPP, when the electricity price is low

in the market. The electric boiler can be used during this period to produce the heat energy and increase the competitiveness of a power plant.

Equations (7.5)–(7.9) are used to calculate the hourly and then annual income, expected in line with *Target No. 1* [59], [125].

The substitution of HOBs with EBs is well founded if the inequality is valid, i.e., the heat production costs of EB are lower than HOB heat production costs.

$$P_i^{Q,EB} < P_i^{Q,HOB}. \tag{7.5}$$

The production costs of heat energy produced by natural gas fired HOBs are assumed equal to the variable component of the production costs, i.e., fuel and carbon dioxide costs (7.6). The fuel costs form up to 80 % of heat energy price of natural gas fired units:

$$P_i^{Q,HOB} = \frac{1}{\eta_{avg}^{HOB}} \times \left(\frac{P_m^{NG}}{NG^{LHV}} + E_{CO_2} \times P_i^{CO_2}\right). \tag{7.6}$$

The production costs of heat energy produced by the electric boiler are equal to the electricity price supplied to the electric boiler (in the Thesis, it is assumed that η_{EB} = 100 %):

$$P^{Q,EB}{}_i = P^E{}_i. \tag{7.7}$$

The hourly income is calculated by (7.8), if the substitution of HOBs with EBs is well founded:

$$Q_i^{EB} \times (P_i^{Q,HOB} - P_i^{Q,EB}). \tag{7.8}$$

The income per year is equal to

$$\sum Q_i^{EB} \times (P_i^{Q,HOB} - P_i^{Q,EB}). \tag{7.9}$$

Equations (7.10) – (7.15) are applied to calculate the hourly and then annual income, which are going to be achieved in line with Target *No. 2* [59], [125].

The substitution of HOBs with EBs is profitable, if two inequalities, i.e., (7.10) or (7.11) are true:

$$P_i^{Q,HOB} > P_i^{Q,BIO} < P_i^{Q,EB}, \tag{7.10}$$

$$P_i^{Q,HOB} > P_i^{Q,BIO} > P_i^{Q,EB'}. \tag{7.11}$$

In case of (7.11), the modified heat production costs of EB are used. They are calculated in line with Eq. (7.12).

$$P_i^{EB'} = P_i^{Q,BIO} - 1. \tag{7.12}$$

It is assumed that in order to be competitive the modified heat energy production costs of EB are by 1 €/MWh lower than the production costs of biomass heat energy sources.

In contrast to the natural gas fired units, the fuel costs of the biomass heat energy sources form until 50 % of the heat energy price. That is why such additional costs as the costs of auxiliary electricity, taxes and other costs are taken into consideration [126]. Expression (7.13) is applied to determine the production costs (variable component) of heat energy produced from the biomass heat energy sources:

$$P^{F,BIO} + 0.03 \times P^{F,BIO} + 0.06 \times P^{F,BIO}, \tag{7.13}$$

where $P^{F,BIO}$ – costs of biomass (raw materials), €/MWh;

$0.03 \times P^{F,Bio}$ – taxes and other costs, €/MWh;

$0.06 \times P^{F,Bio}$ – costs of auxiliary electricity, €/MWh.

The hourly income of electric boiler superiority under the biomass boiler can be calculated as follows:

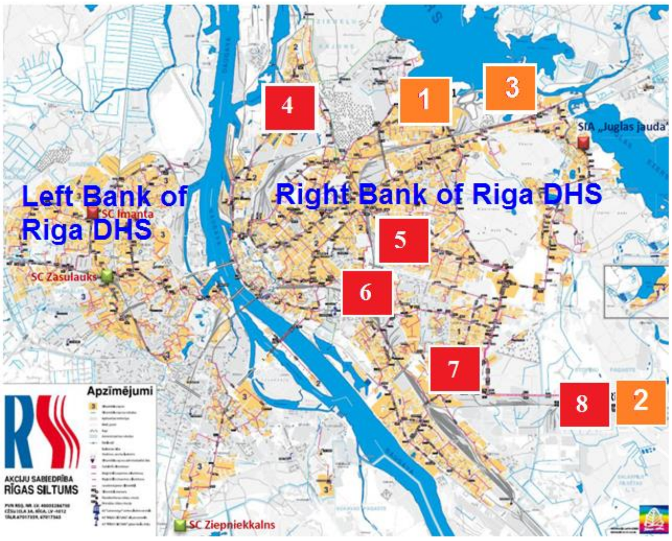
$$Q_i^{EB'} \times (P_i^{EB'} - P_i^{Q,EB}). \tag{7.14}$$

The annual income is equal to

$$\sum Q_i^{EB'} \times (P_i^{EB'} - P_i^{Q,EB}). \tag{7.15}$$

7.3. Practical Application of Methodology

The installed capacity of the electric boiler is assumed 150 MW, due to the unique situation arisen on the right bank of Riga district heating system. This is the appearance of the new biomass heat energy sources with total thermal capacity of 150 MW (Fig. 7.5). In brief, the district heating system in Riga consists of two regions: the right and the left bank, which are not connected. Thermal power plants (Riga TPP–1 and Riga TPP–2) are located on the right bank of Riga district heating system. They together with TPP *Juglas Jauda* (14.9 MW_e and 16 MW_{th}) provide the heat energy to the consumers. The new biomass heat energy sources can offer a lower heat energy price than natural gas fired units. The installed capacity of electric boiler 150 MW is needed to compete with new biomass energy sources. This refers to *Target No. 2* (see Section 7.2). Moreover, electric boilers can be used instead of natural gas heat energy sources during the night or periods with a low electricity price. This refers to *Target No. 1* (see Section 7.2).



Existing heat energy sources in the right bank DHS: 1) Riga TPP–1; Q=493; P=144 MW; fuel – natural gas; 2) Riga TPP–2; Q=1124; P=832 MW; fuel – natural gas; 3) TPP Juglas jauda; Q=16; P=14.9 MW; fuel – natural gas.
New heat energy sources (planned and in operation) in the right bank of DHS: 4) Ltd Eco Energy Riga; Q=15 MW; fuel – biomass; 5) Ltd Rigas Energija; Q=4 MW; P=4 MW; fuel – biomass; 6) Ltd Rigas BioEnergija; Q=48 MW; fuel – biomass; 7) Ltd Rigas BioEnerģija; Q=48 MW; fuel – biomass; 8) Ltd Energia verde; Q=20 MW; P=4 MW; fuel – biomass. If electrical power (P) is omitted, it means it is a boiler house.

Fig. 7.5. Riga DHS and heat energy sources [125].

Taking into account the data analysis of hourly production and the pattern of operation of Riga TPP–1 and Riga TPP–2, the following calculation platform is developed for the analysis of *Target No. 1:*

- $Q^{HOB}_{total} = Q^{TPP-1+TPP-2}$; $t_a \geq -10\ ^{o}C$ the sum of HOB production at Riga TPP–1 and Riga TPP–2, then the power plants operate within the joint district heating system;
- if $Q^{HOB}_{total} \leq 150$ MW, then $EB = Q^{HOB}_{total}$ and $Q^{HOB} = 0$ MW;
- if $Q^{HOB}_{total} > 150$ MW, then EB = 150 MW and $Q^{HOB} = Q^{HOB}_{total} - Q^{EB}$.

The operation hours of HOBs before the electric boiler integration are 5927 hours. Due to the integration of EBs into the heat energy production process, the operation hours of HOBs are reduced from 5927 to 4670 hours. The operation hours of EB correspond to 2663 hours in *Target No. 1* (Fig. 7.6 and Table 7.2).

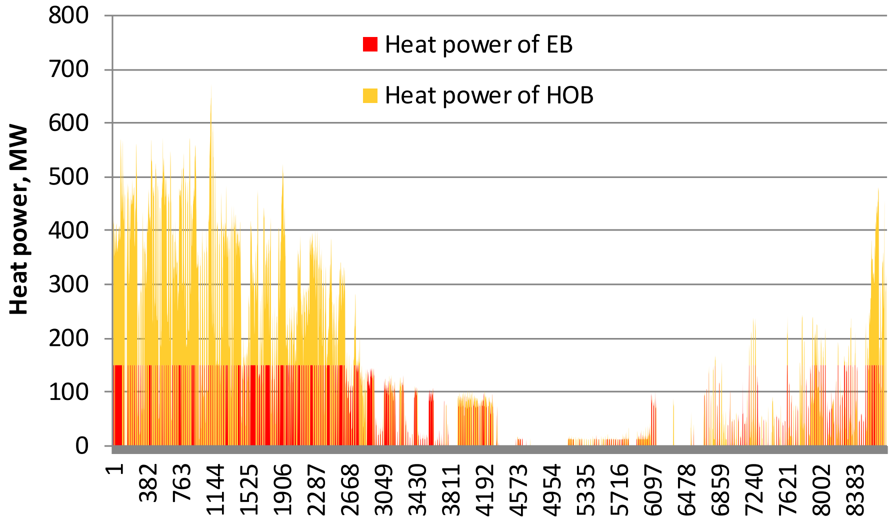


Fig. 7.6. Operation of the electric boiler in line with *Target No.1* [59].

In line with Eq. (7.9), the annual income of substitution of HOBs with EB is 3.3 million € (M€). The use of EB instead of HOBs during the periods of a low electricity price ensures more profitable operation of the power plant. It is assumed that the investment into electric boilers with total heat capacity of 150 MW (equal to the thermal capacity of new biomass heat energy sources) can be approximately 12 M€ [17]. According to [84], the pay back ratio can be calculated as the capital costs divided by the benefit. Therefore, it is up to 4 years.

Table 7.2

Operation Hours of Electric Boiler in Different Situations [59]

Parameters	Before	*Target No. 1*	*Target No. 2*
HOB, h	5927	4670	2681
EB, h	-	2663	336
BIO, h	-	-	5647
Income, M€	-	3.3	0.13

The amount of income in *Target No. 1* is determined by the following parameters: the price of electricity, the number of operation hours, the price of natural gas and carbon dioxide, the size of EB. The first two are the most significant parameters.

To check *Target No. 2*, the calculation platform of Fig. 7.6 is modified taking into account the following conditions and statements:

1. if $P_i^{Q,HOB} < P_i^{Q,EB}$ and $Q^{HOB}{}_{total} \le 150$ MW, then $Q^{EB} = 0$ and $Q^{BIO} = Q^{HOB}{}_{total}$;
2. if $P_i^{Q,HOB} < P_i^{Q,EB}$ and $Q^{HOB}{}_{total} > 150$ MW, then $Q^{EB} = 0$ and $Q^{BIO} = 150$ MW and $Q^{HOB} = Q^{HOB}{}_{total} - Q^{BIO}$;
3. if $P_i^{Q,HOB} > P_i^{Q,EB}$ and $Q^{HOB}{}_{total} \le 150$ MW, then $Q^{EB} = Q^{HOB}{}_{total}$, $Q^{BIO} = 0$ MW and $Q^{HOB} = 0$ MW;
4. if $P_i^{Q,HOB} < P_i^{Q,EB}$ and $Q^{HOB}{}_{total} > 150$ MW, then $Q^{EB} = 150$ MW and

4.1. if $Q^{HOB}{}_{total} - Q^{EB} \le 150 \Rightarrow Q^{BIO} = Q^{HOB}{}_{total} - Q^{EB}$ and QHOB=0;

4.2. if $Q^{HOB}{}_{total} - Q^{EB} > 150 \Rightarrow Q^{BIO} = 150$ MW and $Q^{HOB} = Q^{HOB}{}_{total} - Q^{EB} - Q^{BIO}$.

All the statements can be summarised as follows: if the EB cannot exceed the HOBs, it will not be competitive with BIO (Eqs. (7.10) and (7.11)) and the periods $P_i^{Q,HOB} < P_i^{Q,EB}$ should be taken out from the red area in Fig. 7.5. It results in the illustration in Fig. 7.7. In accordance with Fig. 7.7 and Table 7.2, the EB can exceed the biomass heat energy sources by only 336 hours out of 2663 available, that is why the annual income (125 387 €) is positive, but it is insignificant to payback the investment of EBs.

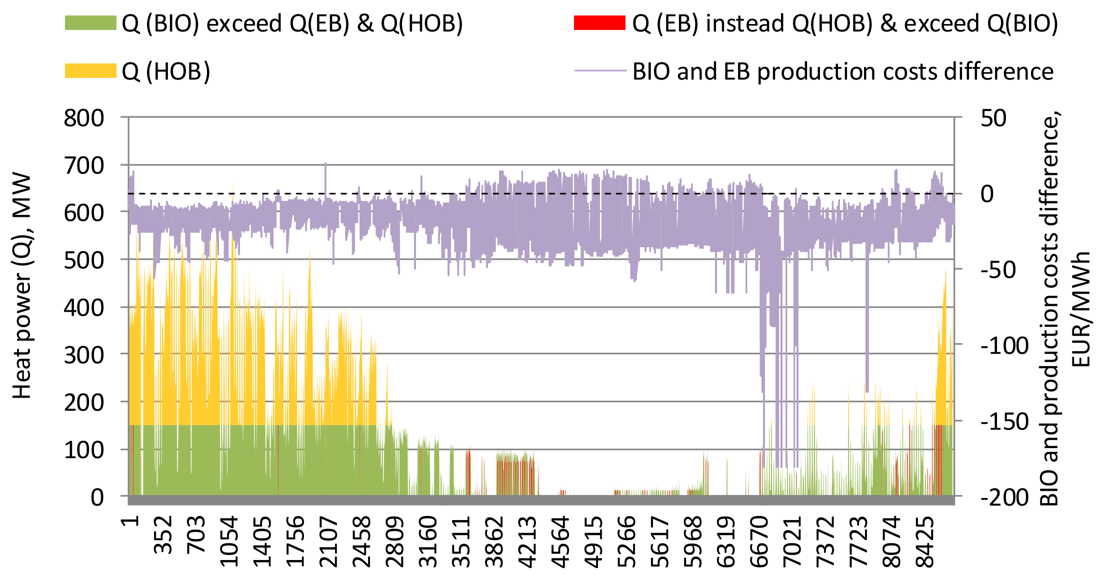


Fig. 7.7. Operation of the electric boiler in line with *Target No. 2* [59].

The main parameters determining the magnitude of income in case of *Target No. 2* are as follows: the electricity price, the number of hours in operation and the price of wood chip.

7.4. Summary

1) The exception of electricity price regulated tariff ensures new opportunities to use the electric boiler at fossil fuel TPPs. This is an important theme for discussion by authorities taking into account the significance of thermal power plants.
2) The economic justification of opportunities to use the electric boiler at fossil fuel TPPs is determined by different parameters. According to the results of the case study, the profitability of EB increases the flexibility of TPP (cogeneration unit) by substituting its generation at night (a low electricity price) and increases its ability to compete with other heat energy sources, when production costs of EB are equal to the market prices and they are low enough, and are influenced by the price of electricity, the number of operation hours, the price of natural gas and carbon dioxide and the size of EB.

8 INSTALLATION OF HEAT STORAGE TANK

8.1. Justification and Technical Solutions of Technology

There are three goals of thermal energy storage (TES) system, which contribute to energy source performance optimisation [75]:

1) The thermal load levelling of heat energy source:
- Reduction in the number of basic equipment start-up and shutdown cycles, thus extending the life-time of equipment;
- Basic equipment operation at higher load;
- Reduction in fuel consumption and fuel costs;
- Replacement of inefficient and expensive equipment by a heat storage tank.

2) The increase in the energy security supply:
- Continuous provision of consumers with heat energy, when the operation of equipment is suddenly interrupted or during the launching of emergency equipment;
- Support of district heating system pressure and temperature during unexpected situations. In case of damage of the district heating system, the heat storage tank can be emptied. Moreover, the heat storage tank can be used as an expansion tank.

3) The increase in the flexibility of energy source operation:
- Flexible energy generation according to electricity price fluctuations in the electricity market;
- Temporary interruption of P/Q (electricity and heat power) ratio;
- Combination of different energy sources.

There are different technical solutions of the thermal energy storage system. More detailed information about technical solutions of TES systems is provided in [127]–[132]. The selection of the heat storage system depends on heat energy storage period, operating conditions, costs, etc. [75]. According to the foreign and local experience, the most common one is the thermal energy system with liquefied storage medium (water), thermal energy displacement (ensuring of stratification) and vertical heat storage tank position [17], [74], [76], for example, heat storage tank (43 000 m^3) at GKM TPP (Germany), which adjusts the operation of the power plant to the situation in the electricity market. Another example is the previously mentioned *Sandreuth* thermal power plant (see Section 2.1): power plant adjustment to the variability of intermitted generation [17], [74], [77].

8.2. Evaluation Methodology of Thermal Energy Storage System

The two situations were evaluated before ($\sum_i (m_i \times \Pi_i)_1$) and after ($\sum_i (m_i \times \Pi_i)_2$) heat storage tank system implementation to define the additional income (Eq. 8.1):

$$\Pi_k = \sum_i (m_i \times \Pi_i)_2 - \sum_i (m_i \times \Pi_i)_1 , \tag{8.1}$$

where i – a characteristic day;

m_i – number of characteristic days (i) during a year, number;

Π_i – profit of a characteristic day (i), €/day.

The profit of one characteristic day (i) is calculated taking into account the electricity price in the market, electricity production costs, amount of the supplied electricity and start-up costs (Eq. 8.2).

$$\Pi_j = \sum_j ((C_j - MC_j) \times P_{j)}) - C_{start\text{-}up}, \tag{8.2}$$

where j – hour in a characteristic day;

C_j – electricity price per hour, €/MWh;

MC_j – electricity production costs per j hour, €/MWh;

P_j – the supplied electricity per j hour, MWh;

$C_{start\text{-}up}$ – start-up costs, €/start-up.

It is important to bear in mind that the benefit from TES system installation can be ensured by the additionally produced electricity and its realisation in the market or by efficiency increase of the power plant (natural gas savings and CO_2 emissions reduction). It is determined by the situation (level of electrical and heat power and equipment content) of a characteristic day. This finding was presented by the author with co-authors at the 4th conference *"From Technical Solution to Efficiency, Flexibility and Competitiveness"* organised by JSC *Rigas Siltums* [77]. In brief, two main outcomes are possible:

1) Thermal power plant is not fully loaded after electrical and heat power. After the installation of heat storage system the electrical power and heat power increase during the daytime. It is necessary to use additional fuel to provide additional electricity production. Thus, there are no natural gas savings and reduction in CO_2 emissions, but additional profit is gained from electricity realisation in the market.
2) Thermal power plant is not fully loaded after heat power, but electrical power is almost equal to the installed one, during the daytime. After the installation of heat storage system the heat power increases during the daytime. The electrical power does not increase (initially is run at maximum) or increases insignificantly (initially is run almost at maximum). The operation of the thermal power plant is shifted to a more efficient operation. Thus, the natural gas savings and reduction in CO_2 emissions ensure additional profit from heat storage system installation.

8.3. Practical Application of the Methodology

The heat storage system is mainly used to level the thermal load and to increase energy supply security during the summer in Latvia [75], for example, two heat storage tanks (2×150 m^3) in *"Vecmilgravis"* and *"Ziepniekkalns"* heating plants and two storage tanks (2×50 m^3) in the boiler house located on 2a *Keramikas* Street, Riga. [17], [74]. It is the first time in Latvia, that the installation of a large-scale heat storage system is evaluated (until 20 000 m^3 or 550 MWh) at the thermal power plant (Riga TPP–2).

Two figures below (Fig. 8.1 – before TES system installation and Fig. 8.2 – after TES system installation) present the example of TES system use in Riga TPP–2. The cycle of the heat storage system is the following: the tank is charged during the daytime, when the electricity price is high; hence, the load of the cogeneration unit is increased. Tank is discharged during the night time, when the electricity price is low; hence, the load of the cogeneration unit is decreased (Fig. 8.2). Comparing both figures (Fig. 8.1 and Fig. 8.2), it is concluded that after heat storage system installation it is possible to obtain the following benefits:

- Operation in mixed mode is replaced with running conditions in cogeneration mode, which ensures a more effective operation of the cogeneration unit, i.e., the decrease in natural gas consumption and CO_2 emissions production (only heat power increases);
- The competitiveness of TPP increases due to a decrease in fossil fuel power plant production costs;
- The operation period extends, where TPP electricity production costs are lower than the electricity price;
- It is possible to gain additional profit from realisation of additionally produced electricity in the market.

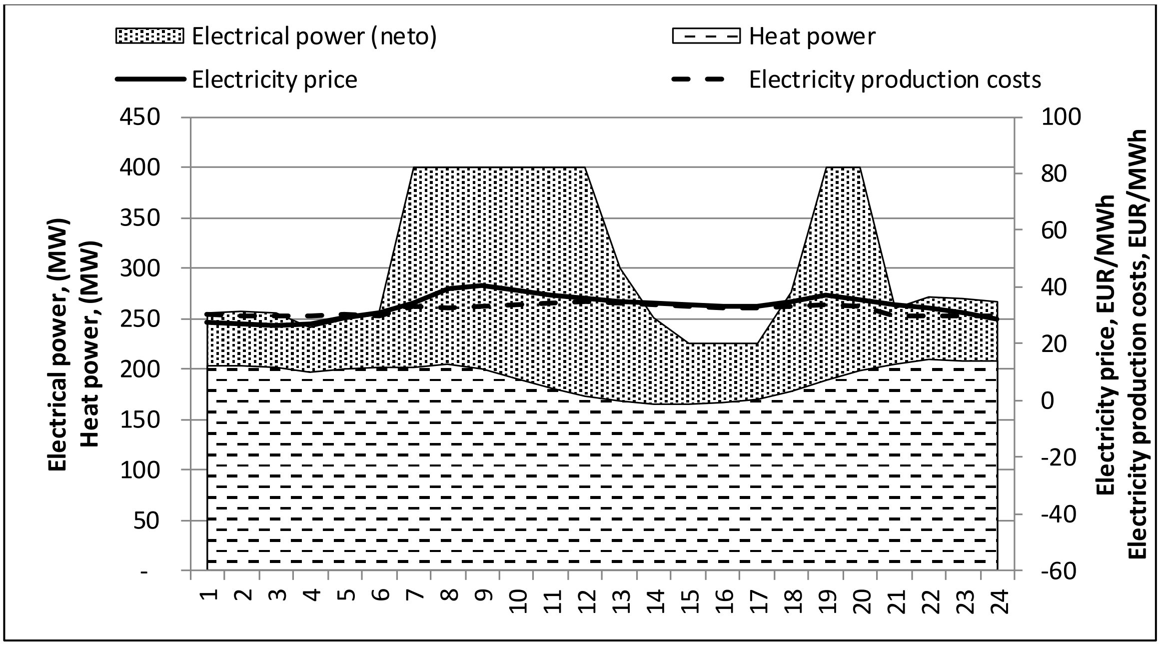


Fig. 8.1. Power of CCGT–2/2 unit before the installation of heat storage system (characteristic day reflects the situation in March).

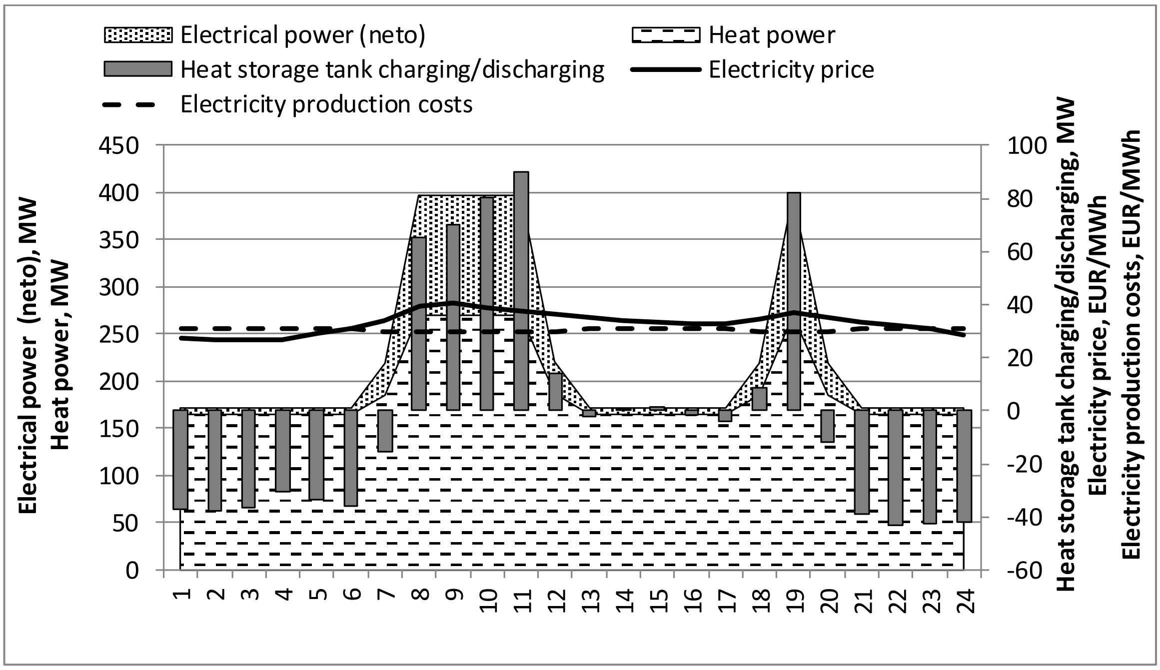


Fig. 8.2. Power of CCGT–2/2 unit after the installation of heat storage system.

The characteristic days (electrical and heat power of units) are synthesized in line with historical production data of Riga TPP–2 and the appearance of new heat energy sources on the right bank of Riga district heating system. The electricity production costs are calculated in line with the internal order of JSC Latvenergo called K260 *"The short-term planning order of primary energy resources produced and supplied in network electricity and heat energy"* taking into account CO_2 price 13 €/t and natural gas price 21.17 €/MWh. The hourly electricity price of typical days is calculated by multiplying yearly electricity price (35.60 EUR/MWh in 2018) by forecast electricity price profiles for working days, which reflect the hourly change of electricity price in % during the typical days (Fig. 8.3).

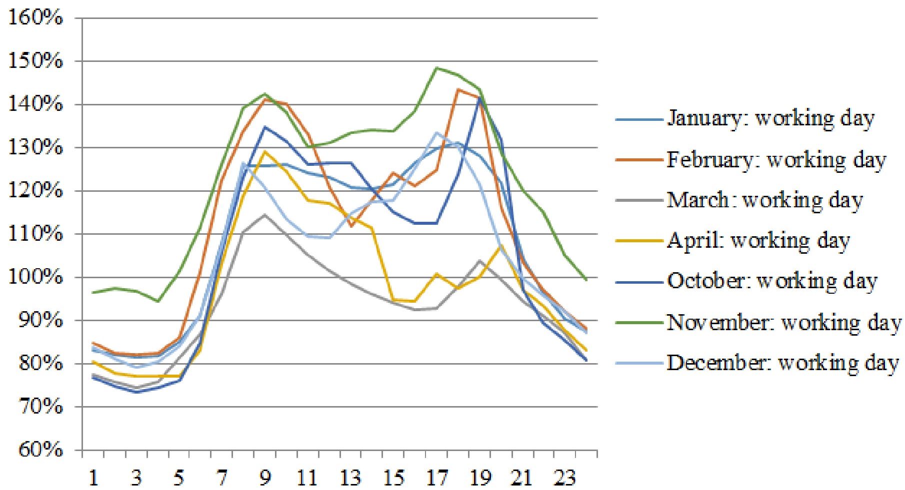


Fig. 8.3. Electricity price profiles for typical days (data from JSC Latvenergo).

The number of typical days and their distribution during the year are synthesized by analysing the historical production data of Riga TPP–2. The total number of days is 144 and their distribution per year is the following: January – 28 days; February – 24 days; March – 12 days; April – 13 days; October – 18 days; November – 21 days and December – 28 days. The heat storage system will not be used during the months from May to September due to the lack of heat load on the right bank of Riga district heating system.

The accumulated heat energy, CO_2 savings and additional income from the installation of the heat storage system at Riga TPP–2 are summarised in Table 8.1.

Table 8.1

Summary of the Calculated Parameters

Month	Accumulated heat energy MWh/24h	Additional income, €/24h	CO_2 emissions, t/24h*	Number of typical days	Accumulated heat energy, MWh/month	Additional income, €/month	CO_2 emissions, t/month
January	365	8 171	51	28	10 222	228 796	1 421
February	347	8 893	48	24	8 328	213 432	1 158
March	345	13 024	48	12	4 140	156 290	576
April	550	5 892	76	13	7 150	76 596	992
October	540	12 013	75	18	9 720	216 240	1 351
November	531	10 938	74	21	11 151	229 691	1 550
December	544	6 050	76	28	15 232	169 391	2 118
Year				**144**	**65 941**	**1 290 440**	**9 168**

*Savings of CO_2 emissions were calculated by Eq. (8.3) [133]:

$$CO_2 = \left(\left(B_{th}^{ref} + B_{el}^{ref}\right) - B^{CHP}\right) \times E_{CO_2}, \tag{8.3}$$

where B_{th}^{ref} – fuel for separate heat production, MWh. It is calculated this way: the accumulated heat energy is divided by the efficiency coefficient for separate heat production. It is 0.92 in line with [134];

B_{el}^{ref} – fuel for separate electricity production, MWh. Accumulated heat energy is multiplied by the coefficient of electricity and heat ratio and divided by the efficiency coefficient for separate electricity production. It is 0.533 in line with [134];

B^{CHP} – the produced energy in TPP, MWh. It is a sum of accumulated heat energy and additionally produced electricity divided by the efficiency coefficient of a unit. It is 0.92 for Riga TPP–2 cogeneration units according to [134];

E_{CO_2} – CO_2 emission factor, t/MWh.

In turn, the economic parameters are presented in Table 8.2. The project is calculated for the period of 20 years. The discount rate of 6 % is used. Electricity, CO_2 and natural gas prices are taken without indexation.

In line with the provided assumptions, the project has a positive result (payback time is approximately 15 years, internal rate of return (IRR) is greater than the discount rate, and net present value (NPV) is positive) if co-financing is obtained. The implementation of the project is unprofitable (payback time is more than 20 years, NPV is less than zero and IRR is less than the discount rate) without co-financing.

Table 8.2

Summary of Economic Parameters

Economic parameters	Without co-financing	With co-financing
Total investments*, thous. €	12 977.71	12 977.71
Own founding, thous. €	12 977.71	9258.75
Co-financing 30%**, thous. €	0.00	3718.73
$NPV_{20,}$ thous. €	- 1776.98	1515.42
$IRR_{20,}$ %	< Discount rate	7.98
Payback period, years	> 20	15.18

* According to the gained practical experience

** From eligible costs

The sensitivity analysis is provided for three price scenarios: low, average and high simultaneous increase in natural gas, CO_2 and electricity price. The forecast profiles are reflected in Fig. 8.4.

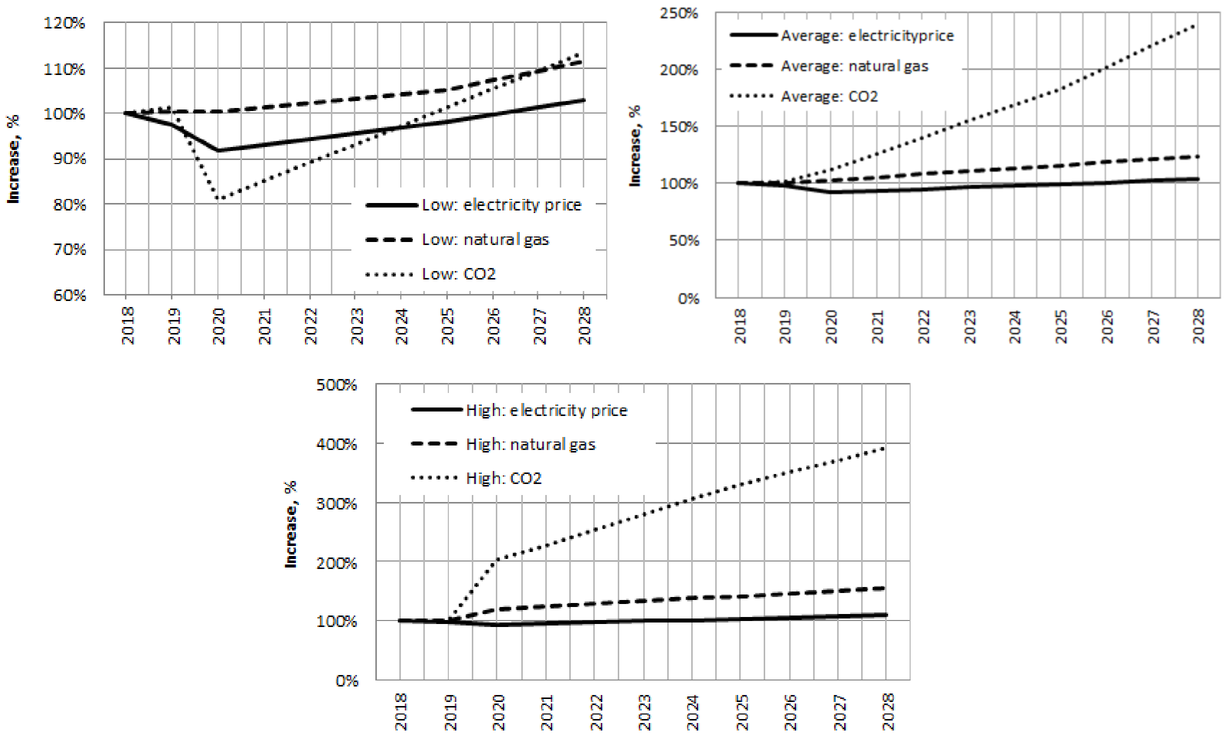


Fig. 8.4. Forecast profiles of the increase in CO_2, natural gas and electricity prices (data from JSC Latvenergo).

In the sensitivity analysis, the forecast price values are for 2028:

- Low price increase scenario (Fig. 8.4): CO_2 price is 8.40 €/t; natural gas – 23.35 €/MWh; electricity price – 35.51 €/MWh. The hourly electricity price is determined by multiplying the electricity price (35.51 €/MWh) by electricity price profiles (Fig. 8.3). Start-up costs are corrected in line with the low price increase scenario. Thus, the calculated additional income is € 1240.60 thous. per year.

- Average price increase scenario (Fig. 8.4): CO_2 price is 17.70 €/t; natural gas – 25.65 €/MWh; electricity price – 35.77 €/MWh. The hourly electricity price is determined by multiplying the electricity price (35.77 €/MWh) by electricity price profiles (Fig. 8.3). Start-up costs are corrected in line with the average price increase scenario. Thus, the calculated additional income is € 994.15 thous. in year.
- High price increase scenario (Fig. 8.4): CO_2 price is 29.00 €/t; natural gas – to 31.85 €/MWh; electricity price – 37.52 €/MWh. The hourly electricity price is determined by multiplying the electricity price (37.52 €/MWh) by electricity price profiles (Fig. 8.3). Start-up costs are corrected in line with the average price increase scenario. Thus, the additional income is not formed in case of the high price increase scenario because the electricity production costs are higher than the electricity price in the market.

The results of sensitivity analysis are reflected in Table 8.3.

Table 8.3

Summary of Sensitivity Analysis

Increase of price	Low price increase		Average price increase	
Availability of co-financing	Without co-financing	With co-financing	Without co-financing	With co-financing
Payback period, years	> 20	14.90	> 20	> 20
NPV_{20}, thous. €	- 1480.68	1537.95	- 3742.16	- 723.52
IRR_{20}, %	4.43	8.13	1.77	4.93

The simultaneous increase in natural gas, CO_2 and electricity price has a negative effect on the heat storage system due to an increase in the electricity production costs above the market price in line with the assumed forecasts of price increase (Table 8.3).

8.4. Summary

1. The heat storage system ensures the decoupling of heat and electricity production and the adjustment of thermal power plant operation to the electricity price fluctuation (obtaining the additional profit) or intermitted generation availability (secure integration of intermitted generation), thus improving the flexibility level of the thermal power plant.
2. The selection of the heat storage system depends on the heat energy storage period, operating conditions, costs, etc. Sensible thermal energy system with liquefied storage medium (water), thermal energy displacement (ensuring of stratification) and vertical heat storage tank position is the most common one.
3. The evaluation methodology of the heat storage tank is adapted to the Latvian site conditions and Riga TPP–2 operation patterns. The obtained results reflect that the situation of characteristic days (value of electrical and heat power and equipment content) determines the source of additional profit: ensured by the additionally produced electricity or by the increase in the power plant efficiency.

CONCLUSIONS

1. The hypothesis of the Doctoral Thesis has been proven: it is necessary and possible to improve the flexibility and efficiency of fossil fuel TPPs in order to achieve the aims (adjustment to variability of electricity price in the market or integration of intermittent generation in the energy production process) and benefits (efficient, profitable, competitive operation of power plants and their prevention from mothballing, secure energy supply) of cycling operation, which vary according to the geographical location of the region, its situation in the energy system and economic development.
2. The literature review reflects that the flexibility level of the fossil fuel thermal power plants can be increased at the design stage or at the operation stage. The measures available at the operation stage are divided into five groups: upgrades of equipment, storage opportunities, operation optimisation, new installation, competitiveness and leadership increase. They differ by the degree of complexity, investment, time of implementation, sources used, etc., but are united by one goal – to enhance the efficiency and flexibility of fossil fuel TPPs.
3. The developed mathematical description of transient modes identifies the parameters of transient modes and the bottlenecks of cycling operation, based on which it is possible to decide on necessary measures to increase the flexibility of TPP. Mathematical description of transient modes has been approbated on the example of Riga TPP–2, which proved that the start-up time (especially cold start-up) of Riga TPP–2 should be reduced significantly.
4. The *EM&OM* approach ensures additional electricity production and reduces the negative impact of the cycling operation on the technical resources of the equipment (the number of cycling periods is reduced and start-ups are replaced with less adverse ones). It can be adapted to other thermal power plants and physical electricity markets by changing the characteristics of the considered technologies, principles of market operation and providing additional calculation. The use of *EM&OM* approach in the intraday market is cost-efficient if the generation portfolio consists of various generation units.
5. The developed general algorithm for technical and economic evaluation of technologies has been adopted to three technologies:
   - The *air chilling technologies* ensure additional electricity production in periods of high electricity price, when TPP operates at maximal power. Its realisation in the market provides additional income, which can be shifted to optimise the price of the produced energy. The efficiency of TPP also improves, i.e., less fuel is consumed to generate more electricity.
   - *Electric boiler* can be used to decrease the production costs and increase the competitiveness of the TPP, when the electricity price is low in the market under condition that the electricity price regulated tariff is excluded. However, the economic justification of technology is determined by different components: the price of electricity, fuel, carbon dioxide, the number of operation hours and the size of the electric boiler.

- The *heat storage system* decouples heat and electricity production. The situation of characteristic days (value of electrical and heat power and equipment content) determines the source of additional income: ensured by the realisation of additionally produced electricity in the market and/or by the increase in the thermal power plant efficiency.

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