METHODOLOGY FOR INVESTMENT EVALUATION IN ELECTRICITY GENERATION MODULES ACCORDING TO THE REQUIREMENTS OF THE EUROPEAN UNION

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For a country to be able to survive successfully, one of the criteria is a stable electric power supply that meets certain technical parameters. In the European Union, several countries are working synchronously to ensure the safety of electricity systems. In order to achieve such synchronous operation, the European Union has adopted Regulation No. 2016/631, which sets out the requirements for grid-connected generators. The present article develops a model to assess the compliance of generators with the requirements of the Regulation, as well as conducts economic analysis to assess which generators need investment and whether their use will provide economic benefits. In this way, the state can create a priority list, where generators are divided according to their socio-economic benefits. In 2025, the Baltic States plan to become integrated into the Energy Systems Association of Continental Europe and work synchronously with the other European Union countries, disconnected from the current BRELL energy systems. Therefore, the model developed in the article is applied to the case of Latvia to determine the necessary investments, as a result of which alternatives are considered for improving the current situation.

Keywords: *Cost-benefit analysis, generating sources, investments, power plants, synchronisation.*

1. INTRODUCTION

Electric power supply is a common national infrastructure system whose parameters must be consistent with the overall economic needs and technical characteristics. Any changes in the external environment or system must be avoided in order to ensure the equilibrium of the system. The functioning of several national energy systems in synchronous mode significantly reduces the costs of operating the energy system and improves overall system safety by reducing the potential adverse effects of local accidents on the stability of the energy system as well as simplifying the maintenance of essential performance parameters of the energy system, such as frequency. In order for the system to operate smoothly, it is necessary to ensure a continuous balance of the electricity produced and consumed, including in emergency situations. Deviation from this balance causes the system to be unbalanced. Electricity balance is characterised by electricity frequency.

The Commission of the European Union (EU) has adopted Regulation No. 2016/631, which establishes a network code on the applicable network connection requirements for generators. The purpose of the application of the requirements is the safety of electricity systems in the European Union (continuous consumer energy supply), including limiting frequency fluctuations at the level allowed for the system, as well as the development of the electricity and ancillary services market and the development of renewable energy sources. The legal provisions of the EU Network Connections Code do not apply to existing electrical equipment, but it provides for a mechanism to apply those legal provisions to existing electrical equipment in the event of significant changes in the energy system

[1], [2]. In cases when the changes are so large that power plants which do not comply with the requirements of the Regulation cannot meet the objectives set out in the Regulation, regulation on the modernisation of existing plants may be adopted, which means additional investment.

In the event that production plants do not fully or partly comply with the requirements of the system, a study on the feasibility of their application and the amount of investment needed must be carried out. The amount of investment is to be assessed from the point of view of the common system and individual suppliers. On the other hand, from an economic point of view, it is necessary to assess losses arising from non-realisation of investment [3], [4]. Without investment, losses are suffered by society, business, and the economy as a whole, not just regarding the amount of electricity not delivered. As a result, these losses need to be calibrated.

The Baltic power supply system is designed to be closely linked to the energy supply infrastructure of neighbouring countries. Historically, the energy systems of Latvia and the other Baltic States have been designed as part of the former USSR unified energy system, in the so-called BRELL energy systems (the energy systems of Belarus, Russia, Estonia, Latvia, and Lithuania), so the Baltic States also maintained the historical electricity infrastructure connections with Russia and Belarus after the restoration of independence in 1991 [5]–[7]. As the Baltic States joined the European Union (EU) and closer links to the EU's energy bloc were established in 2007, the idea was that the Baltic States could work in sync with the rest of the EU. Exploration work began in 2013 to determine the

provisional works and the costs of synchronisation. In 2015, a synchronisation road map was approved, and the Baltic States launched a process of preparations for synchronisation with the EU, scheduled for 2025 [8]. On 27 May 2019, the agreement on connecting the electricity systems of the Baltic States to the continental European grid entered into force. On 20 June 2019, in Brussels, the prime ministers of Lithuania, Estonia, and Poland signed a political road map for connecting the electricity systems of the Baltic States to the continental European grid. At the moment, disconnection from BRELL in the energy circle is taking place. Consequently, in the event of such a cut-off, the continued supply of electricity to consumers is problematic as regards the quality requirements [9]. At present, in the Baltic (2020) normal operating mode, the frequency must be between 49.95 and 50.05 Hz [10]. The energy systems of the Baltic States are facing a major challenge to successfully integrate into the Energy Systems Association of Continental Europe. All transmission system operators within

the Energy Systems Association have to jointly ensure electricity balance through frequency adjustment services [11].

Given the need for the EU countries to carry out an analysis of the application of the Regulation for existing modules to assess the overall operation of the system in emergency situations, including frequency provision, the smaller investments are assessed in a situation where existing modules are evaluated as to the requirements of the Regulation when the site is part of a common EU network.

The main goal of this study is to develop a methodology for assessing investment needs in line with the requirements of Regulation EU 2016/631. To achieve this goal, we perform the following actions:

1. Assessment of the adequacy of modules for the requirements of Regulation EU 2016/631;
2. Cost-benefit analysis (CBA) for existing installations;
3. Assessment of the investment needs of modules.

2. METHODOLOGY AND MODELS

A cost-benefit analysis is a process that businesses use to analyse decisions. The business or analyst sums the benefits of a situation or action and then subtracts the costs associated with taking that action. Some consultants or analysts also build models to assign a money value on intangible items, such as the benefits and costs associated with living in a certain town [12].

The economic analysis has been carried out by an additional cost method, comparing the two project implementation scenarios: the situation without the project and the situation with the project and taking into account only the additional costs and ben-

efits associated with the implementation of the project. According to the CBA Regulation, the following performance indicators may be used: net present value; internal rate of profitability; rate of return; investment payback period. The algorithm uses performance indicators and criteria consistent with the Regulation [13] and the CBA guidelines for the EU investment projects [14], [15]:

- Economic net present value (ENPV): this must be greater than zero in a project that is desirable from an economic point of view;
- Economic rate of return (ERR): this

should be higher than the social discount rate;

- Benefit-cost ratio (B/C): this must be greater than one.

The sensitivity analysis is designed to identify the critical variables of the project that are used in drawing up the cash flow of the CBA. According to the guidelines, it is recommended to consider “critical” variables whose changes (positive or negative) by 1 % of the basic value of the net present value are changed by 5 %. The calculation of limit values may reveal useful information, indicating at what percentage changes the net present value (economic or financial) is zero. The sensitivity analysis indicators are as follows: investment cost changes; full off

(blackout) one event duration; number of full off (blackout) events per year.

The CBA has to be carried out for the reference period, or for the life cycle of the project, starting with the beginning of the project. The reference period or life cycle is the useful lifetime of the fixed assets created under the project, or the economically valid period of the project, during which it is possible to benefit financially or economically from the funds invested in the project or the assets created. The recommended length of the project life cycle in the energy sector is 25 years [16], [17], the reference period recommended by the European Commission in the energy sector is 15–25 years (Table 1) [18], [19].

Table 1. Input Data

Parameter	Input data
Household losses	Not taken into account, no representative study
Economic benefits	Annual value of avoided blackout
Economic costs	Capacity reservation fee Spare capacity x (calendar number of hours per year) x (Nord Pool Spot minus variable costs)
Discount rate (real)	5 %
Assessment period	15 years

In order to determine the financial effectiveness of applying legal norms to existing electrical equipment, electricity generation modules will be considered as electrical equipment within this study. For each module, a number of points following which the relevant model is assessed should be provided for. In the course of the study, a methodology is developed to assess the conformity of models with the requirements of the Regulation, the necessary investments, and losses.

Two types of modules are distinguished: synchronous and park modules. The synchronous electricity generation module (SEGM) is an indivisible set of equipment capable of producing electricity in such a way that the ratio between the generated voltage frequency, the generator speed and

the grid voltage frequency is constant and therefore these indicators are synchronous. An electricity park module (EPM) means an electricity generating unit connected to a network: (1) non-synchronous, (2) by means of an energy electronic (DC) converter, (3) connected to a high-voltage direct current system at a single termination point, (4) in different sets of such units. Each module is broken down to the type concerned, depending on the following active power (P) limits:

- Type A Module: $0.008 \text{ MW} \leq P < 0.5 \text{ MW}$;
- Type B Module: $0.5 \text{ MW} \leq P < 5 \text{ MW}$;
- Type C Module: $5 \text{ MW} \leq P < 15 \text{ MW}$;
- Type D Module: $P \geq 15 \text{ MW}$ or connection to power mains of 110 kV or a higher voltage.

The assessment is carried out according to the methodology in Fig. 1. For each module, its type is defined as SEGM or EPM, its active power and its conformity with type A, B, C or D have to be evaluated. By module breakdown, the requirements of the Regulation have to be structured and the conformity of each type with these has to be evaluated. As a result, a list of the requirements of the Regulation is drawn up. Each SEGM/EPM type and each A/B/C/D type of module are evaluated according to the applicable requirements (task No. 1). If the model complies with all the requirements of the Regulation, it is not taken into account in the subsequent calculations, this kind of

breakdown is applicable as it is possible for their further assessment to be carried out by the CBA (Task No. 2). If the model does not meet a requirement, a technical-financial assessment has to be carried out for each requirement that the model does not meet when determining the required financial contribution (Task No. 3). In order to assess the efficiency of investments, the losses caused to the economy in an emergency situation and the impact on market development and the integration of renewable sources are assessed, depending on a number of safety aspects, namely: frequency, duration, and impact.

Fig. 1. Structure of the methodology developed.

In order to determine the assessment of the CBA and the investment needs (Figs. 2 and 3), it is necessary to define the objective function – maximising the state costs (C_{sc}).

In order to achieve the objective set

in the **first phase**, an investigation into Regulation 2016/631 has to be carried out; each requirement of the Regulation has to be evaluated, and a list of models of types A, B, C and D that must comply with the

requirements of the Regulation is drawn up. Two lists are created, for a war-type model, where the SEGM and EPM types are assessed separately. At this stage, the type of each model for each of the requirements of the Regulation has to be assessed as to whether the model complies with the requirement. If the model meets all the requirements of the Regulation, it does not have to be taken into account in the subsequent calculations. If the model fails to meet any one of the requirements, a technical-financial assessment has to be carried out in the second phase.

If the results of the technical analysis of the system demonstrate a mandatory need for the technical development of the installations of the system, the need for investment is inevitable. In such a case, the issue lies in investment financing solutions. Given that electric power supply system members are economic operators, investments inevitably affect the financial performance of their activities. This means that investments must be able to ensure the financial efficiency of the project and the financial viability of the merchant. If the NPV of the project is negative, it is necessary to provide state aid.

On the other hand, if the results of the technical analysis of the system demonstrate alternative possibilities for the technical development of the installations of the system, the need for investment is justified by an economic analysis.

In the **second phase**, a module which does not meet a requirement of the Regulation has to undergo a financial and economic analysis. In accordance with the Regulation, an analysis is carried out, which determines the costs of ensuring compliance of the defined sites with specific requirements of the Connecting Code, the social and economic benefits resulting from the application of these requirements; cost-benefit performance indicators and the sensitivity of

the project as a result of hypothetical fluctuations in its potential benefits and costs.

For each of the requirements of the Regulation, an estimate of the amount of investment required has to be made, taking into account the technological design and technical state of the existing electricity generation modules, which have to be determined on the basis of the information provided by their operators and the necessary replacement of existing installations or the setting up of additional new installations, as appropriate. The total required investment estimates for all synchronous and park modules of the type [A, B, C and D] concerned are determined on the basis of the information obtained on their number, capacity and existing technological installations used. On the basis of available information on the costs of the reconstruction of similar types and power plants over the past 10 years and assessing the non-compliance of production modules with the relevant requirements of the Regulation, the necessary investments for the implementation of each individual point are identified.

Many energy companies employ techniques that use the annual costs on the electrical grid:

$$C_t = C_{K,t} + C_{E,t}, \quad (1)$$

where

C_t – annual cost in year t , EUR/y; $C_{K,t}$ – annual capital charge in year t , EUR/y; $C_{E,t}$ – operating costs in year t , EUR/y.

$$C_{K,t} = \frac{i}{100} \sum_{j=1}^m K_j, \quad (2)$$

where

$\sum_{j=1}^m K_j$ – total capital investments, EUR; i – an interest rate, %; m – the amount of investment from the beginning of the calculation period to year T .

The operating costs consist of two parts:

$$C_{E,t} = C_{Ek,t} + C_{Em,t}, \quad (3)$$

where

$C_{Ek,t}$ – constant (load-independent) operating costs in year t ; $C_{Em,t}$ – annual operating costs of the variable (load-dependent) t , EUR/y; variable (load-dependent) operating costs in year t , EUR/y.

The constant operating costs consist of the depreciation costs of the equipment and the costs of servicing and maintaining

(repairing) the equipment:

$$C_{Ek,t} = \sum_{j=1}^m K_j * p_a / 100 + \sum_{j=1}^m K_j * p / 100 + C_0, \quad (4)$$

where

p_a – depreciation interest, %; p – interest on servicing and maintenance costs, %; C_0 – rent, taxes, and other constant annual expenses.

The variable (load-dependent) operating costs consist of the cost of power and electric power losses in transformers and lines:

$$C_{Em,t} = C_{\Delta P_L} + C_{\Delta P_{tg}} + C_R, \quad (5)$$

$$C_{Em,t} = \sum \Delta P_L (\tau \beta' + \beta'') + \sum (\Delta P_{tg} (T \beta' + \beta'') + \Delta P_v \left(\frac{S_{maks}}{S_{NT}} \right)^2 * (\tau \beta' + \beta'')) + C_R, \quad (6)$$

where

C_R – costs of reliability of electric power supply, EUR/y, ΔP_L – power losses in the line, β' – electricity loss costs, β'' – power loss costs, ΔP_{tg} – load-independent idling loss, ΔP_v – load-dependent short-circuit losses, T – transformer connection time, h/y; τ – maximum loss hours per year, h/y; S_{maks} – transformer peak load, kVA; S_{NT} – nominal power of transformers, kVA.

The annual costs for selecting project options can be used in two ways:

1. When calculating the net present value for the estimate period:

$$NPV = \sum_{t=1}^T C_t * d_t, \quad (7)$$

where

d_t – a discount rate; T – a calculation period in years.

The optimal option is selected at the minimum discounted annual cost (NPV = min).

2. By determining in advance the estimation level (for loads, loss costs, investments, etc.) at which the annual expenditure is calculated. Determining the equivalent level of the θ of the estimated years, it is necessary to take into account changes in

load and cost veracity at the time (discounting factor and inflation), and the equivalence of static and dynamic criteria:

$$C_\theta \sum_{t=1}^T d_t = \sum_{t=1}^T C_t * d_t, \quad (8)$$

where

C_θ – annual cost estimates per year. The optimal option is selected at a minimum annual estimated cost C_θ per year.

The second project option can be selected if no new objects appear during the estimate period. The first project option is more universal, without the limitations that are characteristic of the second project option but it is more labour-intensive, it should be carried out using the relevant computer programs, such as LDM-V and LDM-VZ.

According to the guidelines of the ENTSO-E (European Network of Transmission System Operators for Electricity), the calculation of the benefits is carried out by calculating the total costs of avoid-

ing total regional power outages. The costs are calculated using non-delivered energy, which depends on the average hourly consumption rate, the value of lost loads and the duration of the break [20]:

$$\text{Non-delivered electricity costs} = \text{VOLL} * \text{consumption} * \text{duration}, \quad (9)$$

where

non-delivered electricity costs are measured in *EUR*, *VOLL* – in *EUR/MWh*; consumption – in *MWh/h*, duration – in *h*.

Value of Lost Load. The determination of the VOLL depends on the level of customer differentiation determined by the depth of the study. It should be noted that there is no uniform size for all European countries, it differs significantly from country to country, which is due to a number of factors.

On the basis of the impact assessment

criteria, the potential socio-economic benefits of the production module have to be determined for each point of the Regulation for which the model does not correspond (prevention of consumer losses) to $C_{\text{non-com}}$ [EUR/15 years] during the period considered, which has to be determined by the following formula:

$$C_{\text{non-com}} = \frac{(N^a * M^b * S^c)}{N^{\text{amax}} * M^{\text{bmax}} * S^{\text{cmax}} * 10^3} * P_N * T_{\text{max}} * V * n_a, \quad (10)$$

where

N – the probability factor (assumed at 10). In the case of Latvia, it is 10, in other power systems it may be determined differently depending on the amount of losses caused by the frequency of interruption of power supply; a – the probability level of the effect: low (value 1) – less than once every 10 years; average (value 2) – once a year; high (value 3 (a max)) – more frequently than once a year; M – an impact scale factor (assumed to be 10); b – an impact scale step: local (value 1) – single substations where production is connected module within borders; regional (value 2) – within the limits of one substation and adjacent substations; national (value 3 (b max)) – impact throughout the territory of Latvia; S – an impact factor (assumed to be 10); c – the degree of importance of impact (minor (value 1) – consumers cause interference in the electricity grid but their equipment continues to operate; essential (value 2): consumer operation is disrupted or temporarily terminated, no complete suspension and launch of equipment is required; critical/distinguished (value 3 (c max)): consumer operation is fully suspended and the period of 4 h or more is required for renewal; P_N – nominal active power of the production module, or group of modules, under consideration, MW; T_{max} – the largest number of hours of operation on average in one year, over the past five years; V – the cost of one unit of energy not delivered to consumers, EUR/MWh; n_a – the period considered in years (15 years assumed). The period considered is adopted on the basis of practical data, where every 15 years there is a need for modernisation, reconstruction or other significant changes in activity or investment.

The coefficients M, N and S are assumed to be 10 as the maximum possible coefficient value. The possible value of the factor is between 0 and 10. The ratios are assumed to be 10, as equipment can have a significant impact on the overall functioning of the system as a result of various events. In the assumptions, the ratio 10 is based on the impact of the criterion: 10 – the largest impact, 0 – no impact. The criteria breakdown from 0 to 10 is taken into account on the basis of risk analysis carried out during the modelling process.

In the third phase, after the calculations have been made, for each clause of the Regulation which does not correspond to the model there is a comparison

between investment costs (C_{invest}) and non-compliance costs ($C_{non-com}$) (task No. 3). This results in a value (C_{sc}) that shows how valuable the model is, as well as whether the socio-economic benefits are obtained by reconstructing the model:

$$C_{non-com} - C_{invest} = C_{st}. \quad (11)$$

The evaluation and calculation of all the points of the Regulations for all models have to result in the drawing up of a list of models, starting with the largest C_{sc} models, in order of priority. Such a list is capable of more objectively assessing and identifying which models require investment primarily in order to optimise electricity infrastructure and optimal investment.

3. RESULTS BASED ON THE EXAMPLE OF LATVIA

As part of the study, the use of methodologies for Latvian modules is developed. In accordance with the requirements of the Regulation, all the generating sources installed in Latvia and connected to the power grid, with a capacity exceeding 0.8 kW, are covered within the scope of the study.

The study uses abstract, plant-class-appropriate, standard equipment parameters and economic performance indicators of merchants, as well as available secondary data.

Information on generating sources is obtained both directly from their operators when they receive replies to the information request questionnaires and from the information previously received by the transmission system operator as well as from the publicly available database of the Central Statistical Bureau (CSB).

Given that, by the deadline set for the completion of the study, no information was received from a large number of the producers whereas the total number and capacity

of the production plants were known, the output data were extended to all the producers, since the introduction of a requirement of the Regulation would affect all electricity generators and consumers, the related costs and benefits.

Also, taking into account the restrained attitudes of the owners of several production modules towards the provision of output data, for a number of parameters for which no accurate reports or complete questionnaires were received, the output data required within the study were calculated on the basis of similar reporting data from similar power plants as well as the data collected by the Central Statistical Bureau of Latvia and other studies on the techno-economic performance of capacity operations within electricity generation. On the basis of studies [21]–[24], approximate estimates were made for different types of production modules in addition to operating costs resulting from the introduction of the requirements of the Regulation.

The study is based on input data

received for the current situation for 2020, assuming that the Regulation has been applied to all power plants put into service after 31 December 2018 (taking into account the transitional rules laid down in the Regulation).

A summary of information on EGMs (electricity generation modules) based on data received and calculated can be found in Table 2. Since each generation source is considered to be a separate module, it is not detailed in the article in the context of sensitive information.

Table 2. Electricity Generation Modules

Type of module	Number of units, pcs.	Total installed capacity, MW	Total annual electricity output, GWh	Income foregone for electric power unit after implementation of the requirement, EUR/MWh	Additional variable costs assumed for the electric power unit following the implementation of the requirement, EUR/MWh	Fixed additional costs per module after the implementation of the requirement, EUR/module per year
Synchronous modules						
A-type	46	12	68	10.00	0.90	400.00
B-type	119	187	1187	10.00	0.90	600.00
C-type	1	6.3	31	10.00	0.12	900.00
D-type	37	2636.30	5680.35	10.00	0.05	1500.00
Park modules						
A-type	282	50.80	90.60	10.00	1.00	400.00
B-type	20	33.40	58	10.00	1.00	600.00
C-type	1	6.90	10.80	10.00	0.18	900.00
D-type	1	20.7	32.40	10.00	0.15	1500.00

Given that no major new production modules are currently being launched and no plans are in place, if certain low-capacity production modules are introduced, they will play a minor role. In order to ensure stability for the power supply system, it is necessary to apply part of the requirement referred to in the Regulation to the synchronous production modules for Type D production, provided that these requirements do not require inadequate investments (the conversion of primary energy carriers to electric energy and/or the conversion of the power part of generators), provided that

these production modules continue to operate long enough after the year 2025 (five and more years). Existing Type D synchronous production modules represent 89 % of the total installed capacity.

On the other hand, the production synchronous modules of types A, B, C and D as well as park modules of types A, B, C and D represent a relatively small part of the power supply system (approximately 11 % of the installed capacity: ~ 320 MW), but their large number (several hundred) poses a risk that their administration might be technically complex and labour inten-

sive, as well as the implementation of the requirements is technically disproportionately complex and therefore the introduction of the requirements of the Regulation for these production modules (existing electrical equipment) is not socio-economically justified. In addition, it should be noted that there is a reduction in capacity in this module segment (closure of modules) due to the government policy of the Republic of Latvia to minimise the production of subsidised electricity (in order to minimise electricity tariffs), particularly in view of the fact that state aid has been fixed for a period of 10 to 20 years and a moratorium on the granting of new rights has been established since 2012 [25].

Consequently, when deciding on the modernisation of existing power plants (rebuilding in line with the requirements of the RfG (Commission Regulation (EU) 2016/631 of 14 April 2016), it should also be taken into account whether improvements are justified for the remainder of

plant lifetime.

In addition, it should be noted that a large proportion of these producers work according to the schedules of heat load schedules (combined heat and power plants); available water resources (hydro-power plants, 29 MW) or wind (wind power plants, ~ 78 MW), which means that a large part of these production modules are not permanent and their adaptation to the stability of the system is technically difficult.

Although the reporting data show that during the summer months the synchronous and park modules of types A, B and C represent a relatively large proportion of generation, even for a relatively long proportion from the hours of the day, the consumption needs in these periods are mainly met by imported electricity from sources outside Latvia. Consequently, the benefits of applying the RfG requirements to modules of types A, B and C are not relevant during these periods (Table 3).

Table 3. Costs of Existing Electricity Generation Modules and their Socio-Economic Effect over 15 Years, if the Requirements of the Regulation are Introduced

Type of electricity generation modules		Costs of implementing RfG over 15 years, in EUR million	Social benefits of applying the requirements of the RfG over 15 years, in EUR million
Synchronous modules	A-type	3.93	4.82
	B-type	34.37	161.43
	C-type	0.67	15.43
	D-type	106.61	3681.10
Park modules	A-type	22.68	8.44
	B-type	9.88	11.04
	C-type	1.18	4.53
	D-type	2.32	18.66

Comparing the costs of the introduction of the RfG (investment and operational) to existing electricity generation modules (EEGM) over a period of 15 years with the

socio-economic benefits of society, the benefits of all EEGM, excluding type A park modules, exceed the costs (Table 4).

Table 4. Investments Needed to Ensure the Eligibility of D-type Modules in EUR (*thousands*)

Number of aggregates (SM)/Modules (PM):	D-type synchronous modules P ≥ 15 MW or 110 kV connection	D-type park modules P ≥ 15 MW or 110 kV connection
Number of aggregates (SM)/Modules (PM)	37	1
Total installed capacity (MW)	2 636.30	20.70
Necessary investments		
F – Frequently defined active power response	12 063.50	461.19
B – Balancing reserves	1 436.26	18.70
Supply of R - jet power:	6 032.20	49.86
P – Overload control	35.50	12.46
a – Protection measures	76 227.19	1 520.81
Category C – other	4 462.30	152.11
Total:	100 256.95	2 215.13

4. DISCUSSION

In theory, there are a number of technical alternatives (Table 5), the implementation of which would ensure stability for the power supply system. Each of these alternatives requires both investment and state funding for their maintenance and there are different risks for both their disposal and operation. These risks are both legal and related to the creation of a partly regulated market with an extremely limited range of competitors, a possible monopoly position with only one supplier participating.

Below follows a list of potential alternatives for solutions which, by applying the Regulation to the limitations and socio-economic benefits of existing electricity generation modules, will ensure that the objectives set out in the Regulation are achieved. In order to ensure the stability of the system, modules are allocated according to capacity and impact on the functioning of the whole system. According to the authors' estimation,

the planned capacity demand was calculated on the basis of potential deficit.

Alternative A: Modernisation of Type D synchronous modules ("Big", with a power of 15 MW or with a connection to a network of 110 kV or more); inefficient operation of power plants (irrespective of the timetable for heat load schedules and stock market prices for combined heat and power generation units of 220 MW; 1280 h/year and/or regardless of market prices for hydroelectric power plants); in this case, modernisation would mean the implementation of the requirements of the Regulation, and in addition to ensuring stability for the system, it would be necessary to maintain switched production modules in such modes as to guarantee capacity reserves (primary frequency adjustment (retention) reserves) FCR of +/-10 MW and (automatic frequency renewal reserves) aFRR of +/-30 MW [information from TSOs]. It

should be noted that investment is assumed to be implemented in all synchronous modules, but it is likely that these investments may be significantly reduced if one of the existing modules ceases to operate or is fully rebuilt and loses its “existing electrical equipment” status.

In addition, it should be noted that this is the only alternative, which can provide all the necessary technical functions for sound operation of the power supply system.

Alternative B: Construction of a “new” internal combustion engine power plant $12 \times 8 \text{ MW} = 96 \text{ MW}$. Operating $12 \text{ MW} + 36 \text{ MW}$ 1280 h/year regardless of stock market prices; investments of 0.5 MEUR/MW [26]; $96 \times 500 = 48 \text{ MEUR}$; fixed operating costs of 15 EUR/kW/year and variable costs of 0.5 EUR/kWh [26], which in our case means investment of 48 MEUR and operating costs. This alternative has a number of technical limitations, which do not allow it to be considered as a fully-fledged alternative: (1) a limited operating hour resource of the power plant, which does not permit permanent operation of such a type of power plant; (2) this power plant has to be used as a “cold” reserve, so that it can only provide functions which allow for the supply of additional active power to the electrical power system for five minutes or more within minutes.

Alternative C: Installation of high-capacity batteries; taking into account the permitted discharge levels and reservations of electrochemical batteries, it is estimated that a battery with a capacity of 45 MWh is required for FCR $\pm 10 \text{ MW}$; an aFRR $\pm 30 \text{ MW}$ battery of 130 MWh is required to provide an aFRR of $\pm 30 \text{ MW}$. Estimated cost of construction of the above batteries: 14.248 MEUR and 41.924 MEUR, total 56.172 MEUR. The estimated operat-

ing costs are related to energy losses and servicing: FCR of 162 767.10 EUR/year and aFRR of 310 400.44 EUR/year. Due to the ageing of battery cells, they should be replaced once in every approximately 2000 full cycles of charge/discharge, which would be every 15 years in the case of FCR and would cost 4.5 MEUR; in the case of aFRR the replacement time would be every 7.5 years and the cost would be 13 MEUR. Nor is this alternative capable of fulfilling all the functions provided by synchronous Type D modules and therefore is not considered to be technically equivalent.

Alternative D: Installation of high-capacity batteries and controlled (harmonised) consumer switching through an aggregate service. As part of this solution, it would be possible to reduce the number of battery charge/discharge cycles per unit of time and thus increase the length of the battery cell replacement interval. As part of this study, it is assumed that such a solution would allow the intervals to be increased twice, respectively, in the case of FCR to 30 years and in case of aFRR to 15 years. This option assumes that half of the charge/discharge energy will be “absorbed” (increased load) and “returned” (reduced load) by consumers. The energy costs would be EUR 80.00/MWh in such a case. There would also be an additional payment for the delegated load of EUR 10.00/MW. The calculations show that this alternative becomes economically competitive when it is possible to “take” and “return” electricity from consumers, at a price close to the average market price of EUR 40.00. This alternative is also incapable of fulfilling all the functions provided by synchronous Type D modules and is therefore not considered to be technically equivalent (Table 5).

Table 5. Technical Alternatives that would Ensure Stability for the Power Supply System

Alternative	Technical solution	Investment costs (million EUR)	Additional operating costs per year (million EUR)	Risks
A.	Modernisation of Type D synchronous modules (with a capacity of 15 MW or connections of 110 kV and above); operation of power plants in inefficient mode (220 MW; 1280 h/year)	100.26	3.04	<ol style="list-style-type: none"> 1. In view of the existence of two such production modules and the need for maintenance on a regular basis, there is a risk that there will be only one production module operating for approximately 720 hours a year, which may participate in frequency adjustment and, in the event of failure, the system may remain without frequency adjustment (n-1 security factor) 2. There is a risk that there will be insufficient competition in the frequency regulating market
B.*	Construction of a “new” internal combustion engine power plant 12 x 8 MW = 96 MW (12 MW + 36 MW, 1280 h)	48.00	2.36	<ol style="list-style-type: none"> 1. There is a risk that there will be insufficient competition in the frequency regulating market, although this will be less than in the case of A 2. A substantial increase in the costs of building a power plant may be possible, which can only be determined more precisely after defining the parameters of the decal and selecting a specific location
C.*	Installation of high-capacity batteries	56.17	2.48 (0.47)*	<ol style="list-style-type: none"> 1. There is a risk that there will be insufficient competition in the frequency regulating market, although this will be less than in the case of A
D.*	Installation of high-capacity batteries and establishment of a demand unit	58.17	3.29 (1.86)**	<ol style="list-style-type: none"> 1. Organisational and legal risks: it may not be possible for a sufficiently large consumer to view and agree on the necessary investments and on a pattern of cooperation within a reasonable period of time 2. Technical risks: a new, relatively large, and complex system must be developed, which has not yet been accredited under the conditions of Latvia

* – Alternatives B, C, and D cannot be considered to be technically equivalent as they cannot technically meet the requirements of Type D synchronous modules set out in the Regulation

** – Costs exclusive of replacement of battery cells 1 x 15 years (FCR) and 1 x 7.5 years (aFRR)

*** – Costs exclusive of replacement of battery cells 1 x 30 years (FCR) and 1 x 7.5 years (aFRR)

In the example of Latvia, it is necessary to carry out a quantitative study on the application of the RfG provisions only for the modernisation of existing Type D synchronous production modules, while also examining alternatives B, C and D as an additional technical means of improving the reliability of power supply. The consideration of alternatives is also desirable given that Type D synchronous modules operate on heat load schedules (combined heat and power plants) or available water resources (hydropower plants), and taking

into account the market situation on the electricity exchange (hydropower and combined heat and power generation units in condensation mode or with heat batteries), the continuous operation of these modules involves additional costs or is even technically limited.

Alternatives B, C, D should be used to supplement certain functions to apply the requirements of Type D synchronous production modules for RfG, or additional measures should be included to ensure the stability of the power supply system.

5, CONCLUSIONS

The developed methodology is to help to assess the need for investment in line with the requirements of Regulation (EU) 2016/631. It is assessed by type SEGM or EPM and by type A, B, C or D as regards the active power and its type. This methodology provides the possibility to make the necessary investments in ERM in higher quality and with greater economic benefits, by grouping them according to the effectiveness of the return on investments.

In the case of Latvia, the application of the requirements of the Regulation to Type D synchronous electricity generation modules is socio-economically justified. For other types of production modules, the introduction of the requirements

of the Regulation in socio-economic terms is not justified, due to their relatively small impact on the electric power supply system and, in addition, their expected mass decommissioning, which will make the share of these modules even less relevant in the overall producer capacity balance sheet and reduce the expected socio-economic benefits (reducing the efficiency of investments in the RfG). Therefore, in accordance with Article 4 of the Regulation, it is recommended that a thorough and transparent quantitative cost-benefit analysis be carried out in accordance with Articles 38 and 39 of the Regulation for synchronous production modules of Type D.

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