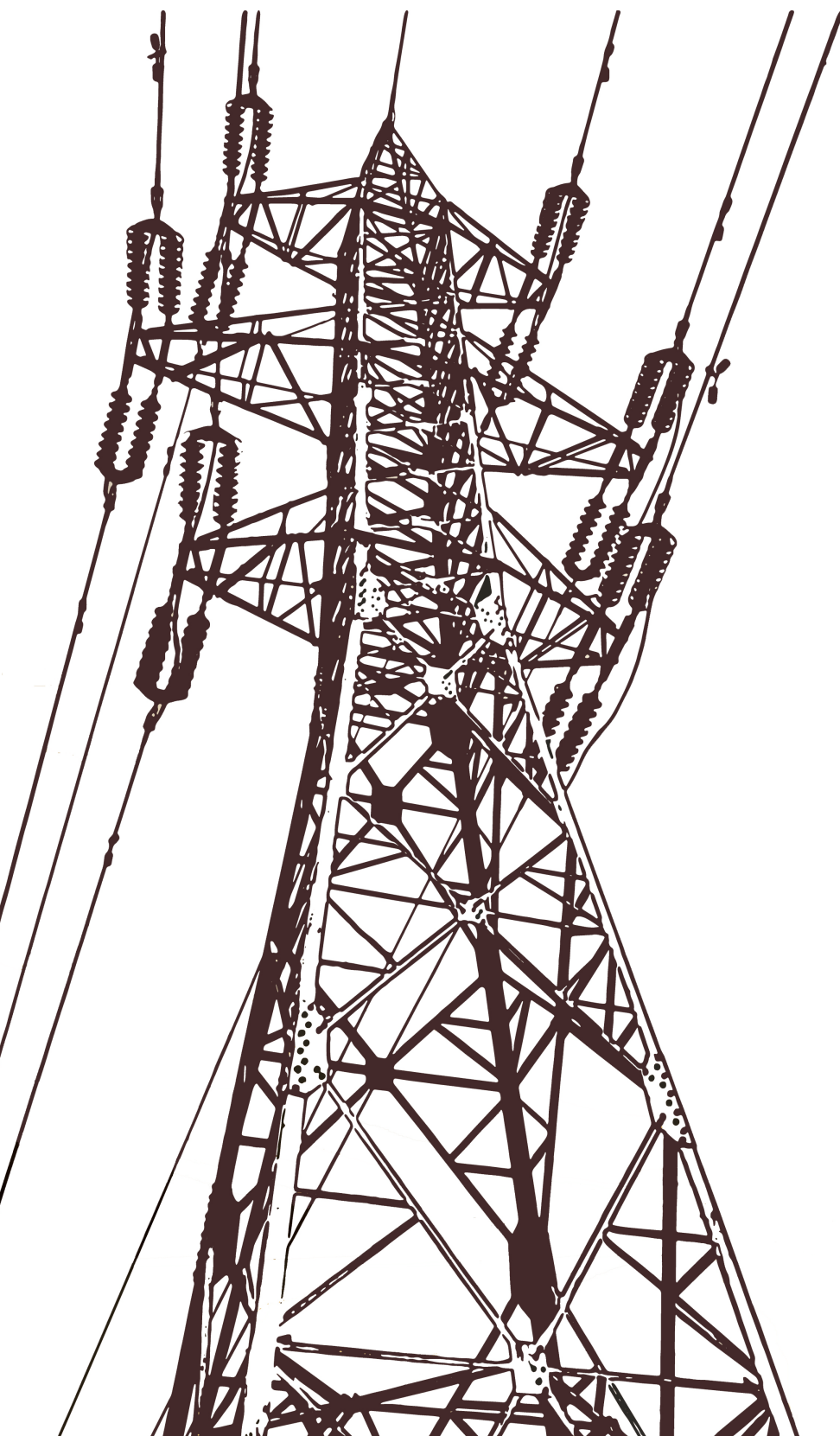


# Capacity Market

## as means to avoid blackouts

Assessment of the impact of implementation of a comprehensive capacity market mechanism in Poland



**PKEE**  
Polish Electricity  
Association

# Introduction

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We have the pleasure of presenting yet another report by the Polish Electricity Association (Polski Komitet Energii Elektrycznej - PKEE).

This publication is a detailed response to our industry's fundamental question: how do various electricity market models influence the growth potential of the power system in view of assuring security of supply? We stand firm by our opinion that discussion about Polish economy cannot be held without referring to the fundamental issues of energy supply security and continuity.

Conclusions of our study indicate the need to urgently commence efforts aimed at improving the effectiveness of electricity market in Poland. **Failure to do so will adversely impact broadly understood social welfare, primarily due to increase of the cost of supplying electricity to end-users.**

At the same time PKEE appreciates the changes recently taking place in the electricity market – in particular introduction of strategic and operating reserves and announcement of introduction of capacity market. In the transition period before its introduction the key issue seems to be the continuation of reform of the wholesale electricity market and ancillary services. In our opinion the regulatory priority should be to reflect the real value of electricity in instances of supply deficit threat and faster development of the DSR (Demand Side Response).

We hope that the PKEE report will positively influence the quality of discussion about the capacity mechanisms and the electricity market model in Poland.

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## Executive summary

### I. Analysis of the situation

The problem with assuring sufficient generating capacity volume in electricity systems is known not only to Poland. It affects many regions in Europe and in the world. The risk of electricity outages has sparked a public debate on effectiveness of the single-commodity market (EOM – Energy Only Market) and the cost of potential electricity supply interruptions for end users.

**The European Union's climate and environment policy significantly influences the operation of electricity markets and their form.**

Growth of renewable energy sources is stimulated by widely-used subsidy systems. Such situation leads to interference with operation of the electricity market models making effective competition difficult. Capex subsidies and low variable expenses of generation of electricity from the renewable sources reduce the operating time of conventional units, which still are needed to assure continued electricity supply.

In consequence the revenues generated by conventional units do not fully cover their CAPEX and OPEX. This results in cash shortages – referred to as the “missing money” problem. When the total costs of energy generation are not being recovered, electricity generation becomes a high risk business. In attempts to mitigate this risk, conventional electricity generators are forced to prematurely retire their generating units.

**In light of dysfunctional operation of the EOM, which does not provide the operators with return on investment, investment decisions are being limited or completely abandoned.**

In consequence we have to deal with the “missing capacity” problem that means a drop in generating capacity caused by lack of investments in new capacities. Parallel existence of the “missing money” and “missing capacity” phenomena threatens the stability of electricity supply. The described situation is being reflected in current projections of the power requirements plans developed by the Transmission System Operator (TSO), as well as by numerous historical instances of shortage of supply.

**With lack of appropriate economic signals, by 2025 ca. 10 GW generating capacity will be retired in Poland, and problems with system balancing may be experienced as soon as 2020.**

## II. Scenarios for Poland

This report provides an analysis-based response to the question on how do specific electricity market models influence the possibilities of development of Poland's electricity system while maintaining the assumed security criteria.

**To assess the consequences of using various mechanisms in the electricity market from the point of view of social welfare, three scenarios were analysed:**

- **EOM** (energy only market) – scenario assuming evolution of current market regulations governing the electricity only market.
- **EOM plus** – scenario assuming evolution of current energy market regulations including elements of capacity reserve valuations but only as current operating reserves and the strategic reserve.
- **CRM** (capacity pricing mechanisms) – scenario assuming elimination of the existing current operating and strategic reserve valuation solutions and evolution of market mechanisms towards separate valuation of electricity and capacity through introduction of comprehensive capacity market.

In case of EOM plus and CRM scenarios the analysis of the criterion of optimisation of social welfare was supplemented with constraint of loss of load expectation in the national electricity system to 3 hours per year, in other words one day of peak hours imbalance in 5 years.

The conducted analysis provides a view on the costs incurred by the consumers and producers of electricity in each scenario. The above costs include in particular the CAPEX and OPEX of renewable energy sources and costs of importing electricity – differing depending on scenario.

The EOM scenario assumes a "liberal" market evolution option. It contains an implicit paradigm of rationality of investors as well as full autonomy of market players. It thus assumes that unprofitable power plants will be retired, also showing the limited role of the regulator and the transmission system operator in a fully liberal electricity market. According to our forecasts even with this scenario the prices to end-users will increase. Thus the EOM option is thus beneficial to very few and costly to nearly everyone, particularly if we consider the cost of energy not served and the damages to the economy resulting out of just the threat of such situation.

**The total cost of unserved energy in the EOM scenario in 2030 perspective is PLN 37.6 billion.**

The EOM scenario should be considered as somewhere in-between the EOM and CRM, close to the status quo. By nature it is a temporary and short-term solution, as it does not solve the problem of investment capabilities deficit and missing capacity in a comprehensive manner. It reminds of applying just small dressings (Interventional Cold Reserve, Operating Reserve) to badly infected and non-healing wounds. This is why PKEE advocates the concept of introduction of capacity market in Poland.

**CRM is the most effective scenario from the social welfare point of view. The two other scenarios imply much higher cost to the economy: EOM plus (by PLN 1.93 billion per year) and EOM (by PLN 3.18 billion per year).**

**Introduction of capacity-based payments, both in the CRM and in EOM plus scenario does not significantly influence the generation mix in the 2030 perspective.**

**Considering the difference in costs incurred by end-users in these scenarios, financing maintaining generating capacities and demand reduction allows average savings of around PLN 10.1 billion a year with respect to the scenario not using such tools (EOM).**

This number may be interpreted as the estimate of maximum cost of capacity mechanisms the end-users would support.

The conducted analysis also demonstrates that solutions consisting of migration by the TSO as of 2014 from the EOM to EOM plus mechanism positively influence the cost of operation of the system.

**The use of Interventional Cold Reserve and Operating Reserve mechanisms contributes towards annual average improvement of social welfare by around PLN 1.24 billion in the projected horizon.**

The report also points out the need for further reform of the electricity market and correct parameterisation of the above mechanisms until the capacity remuneration mechanism (CRM) is introduced, and in our view it should be done by:

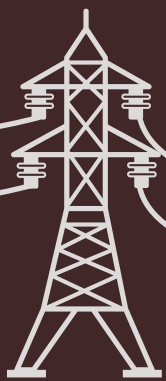
- harmonisation with neighbouring systems, and ultimately elimination of price caps on the wholesale market to reflect the real value of electricity to end-users
- stimulation of development of demand side response (DSR)
- making the valuation of operating reserve a function of market LOLE (Loss Of Load Expectation) and CONE (Cost Of New Entry) parameters, meaning also a removal of price caps in this mechanism
- expanding the scope of use of the Interventional Cold Reserve service to the level resulting from the analysis performed, i.e. a volume that would cover the temperature sensitivity of the National Electricity System between winter and summer (2.5 GW)
- improvement of operation of the ancillary regulating services that should be supplementing the capacity market with correct valuation of location signals and of flexibility of generating units as well as the demand side in responding to variations in demand and generation from renewable energy sources.

Above efforts combined with implementation of the capacity mechanisms (CRM) assure the highest social welfare among the analysed market mechanism variations.

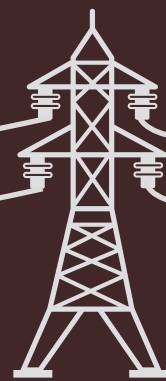
**The capacity market mechanism is capable of providing improvement of social welfare by around PLN 1.93 billion a year compared to EOM plus.**

**From the perspective of consumers, forsaking the efforts recommended in this report may have far reaching consequences of dramatic decrease of security of supply and increase of their costs by over PLN 10 billion a year.**

The total cost of energy  
not served in the EOM scenario  
in 2030 perspective is



PLN **37.6**  
billion



Maintaining  
generation  
capacities

Demand  
reduction

Increase  
of welfare



+



→



=

PLN **3.2**  
billion p.a.

From the perspective of  
consumers, forsaking  
the efforts recommen-  
ded in this report may  
have far reaching con-  
sequences of dramatic  
decrease of security of  
supply and increase of  
their costs by over



PLN **10**  
billion a year

Polish and international experience shows that in the long run a energy only market <sup>1</sup>(EOM) is not capable of developing sufficient incentives for investments in new (“dispatchable”) generating capacities, particularly with lasting low profitability of the generation sector. Investors’ appetite for long-term risk decreases with the growing number of regulatory interventions disrupting the energy market that has been in place since many years. The main change that adversely influenced the profitability of the conventional energy sector in Europe was the dynamic growth of investments in renewable energy sources (RES) in recent years.

Considering the characteristics of the Polish power sector, i.e. particularly: the fuel mix, transmission and distribution grid topology, the degree of commercial availability of storage technologies and smart grids, **the most cost- and technology-effective means guaranteeing electricity supply security are still utility power plants.**

Depending on the pace of democratisation of the power system, including technological progress, the role of conventional energy industry will be changing, however majority of analyses point to no possibility to discontinue using the utility power plants both in Poland and in Europe. This conclusion is not changing even in the 2050 perspective. We must not forget that the pace of decentralisation of the electricity system has to give consideration to affluence of the population and its readiness to bear much higher costs relating to faster transformation of the electricity system.

As examples from abroad demonstrate (e.g. the USA), introduction of capacity market mechanism guarantees that cost effective generating units are kept in the system, and stimulates in a balanced manner both the development of the demand side and investments in new generating assets. Thus the total level of cost of assuring electricity supply security is lower, meaning it is incurred most effectively from the point of view of the end-user.

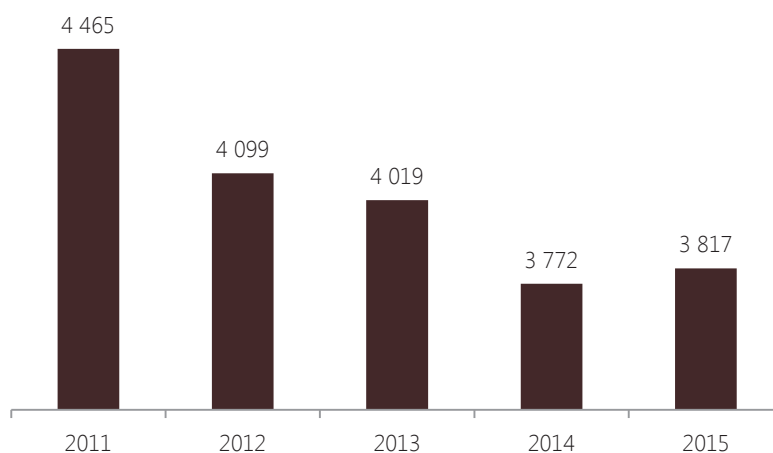
## 1.1. Security of supply

Global experience shows that increased energy production from subsidised RES resulted in particular in drop of wholesale electricity prices and decrease of operating time of conventional units, making it difficult to recover all operating expenses and accumulate capital for new development and modernisation-overhaul projects.

1. Where the revenues of producers come in vast majority from sale of electricity on the wholesale market and directly to end-users.

## Average time of operation of hard coal fired generating units in Poland at full load in 2011-2015 [FLH]

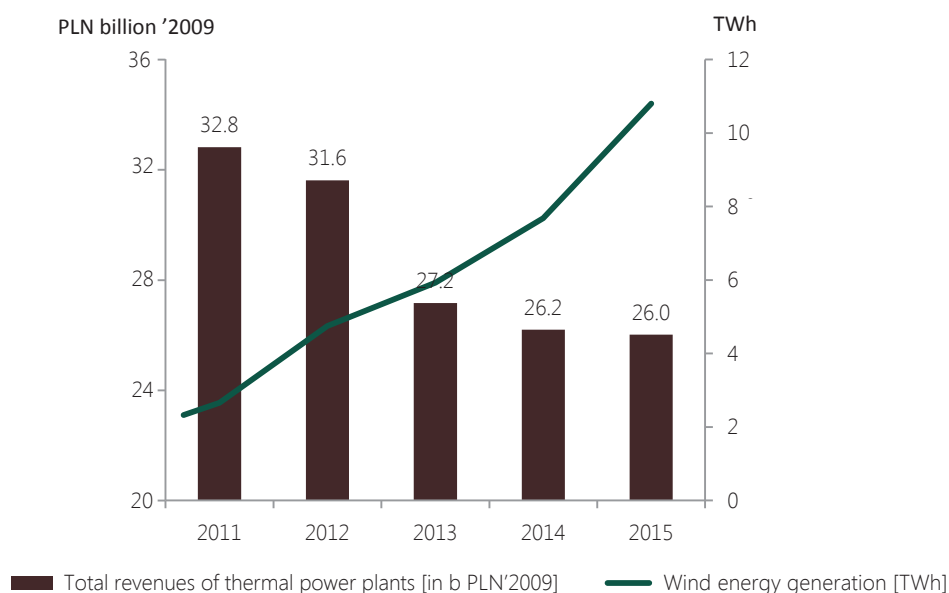
PKEE in-house analysis



Global literature refers to the drop in profitability of conventional energy sector as “missing money”. Long-lasting low profitability of the electricity sector leads to subsequent problem referred to as “missing capacity” – investors refrain from building new capacities even in face of forecasted short- and medium-term insufficient capacity reserves in the National Electricity System.

## Revenues from thermal power plants market versus wind energy generation in 2009-2015 [PLN billions; TWh]

PKEE based on data from Polish Energy Market Agency



The problem with assuring appropriate energy supply security is not only a Polish problem. It affects many countries around the world, with serious implications for entire economies, as stable growth requires uninterrupted energy supply at affordable prices.

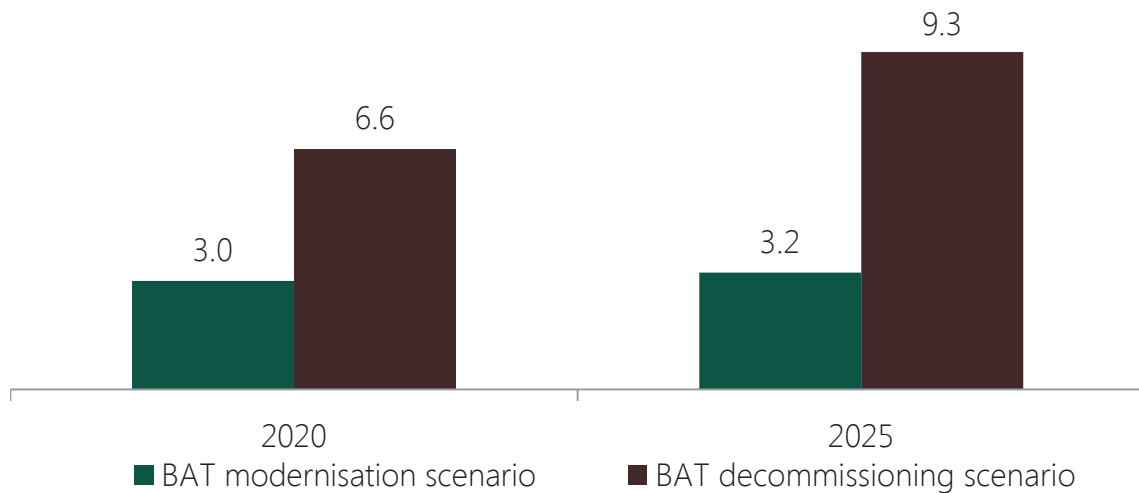


Also in Poland assuring energy supply security is becoming ever more difficult. We are noting premature (for economic reasons) decommissioning of conventional capacities built in other reality and lack of sufficiently numerous investments in new power plants. At the same time the single-commodity market is not encouraging long-term replacement investments. Therefore the overriding goal ahead of the capacity market is to guarantee electricity supply security at the lowest possible cost.

According to forecasts by the Transmission System Operator (TSO) over the next decade, depending on the extent of adaptation of generating units to the BAT (best available techniques) requirements, **between 10 to 30% of existing conventional capacity will be retired from the National Electricity System.** For such a serious transformation of the domestic fuel mix not to threaten the energy security of the country it is necessary to implement the tools improving the certainty of investments in new conventional capacities and stimulating faster development of the demand side response (DSR).

#### Planned decommissioning of existing generating capacities until 2020 and 2025 [GW]

PKEE based on PSE data



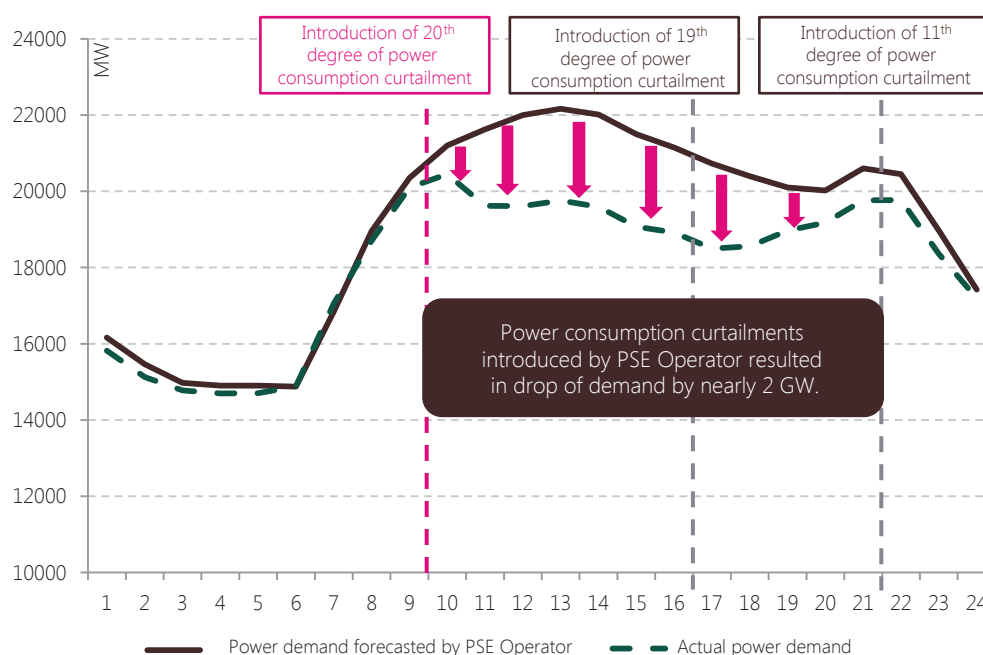
The TSO forecasts that in case of lack of economic motivation for generators to adapt their generating units to the BAT requirements and without implementation of new investments except the projects already in progress, as soon as in 2020 the National Electricity System may reach situation of insufficient surplus capacity. At the same time the authors of the analysis stress the fact that due to economic unfeasibility of capital-intensive adaptation of power plants to the new environmental regulations, generators are planning decisions on not modernising and possibly retirements. In this context introduction of the capacity market may improve economic effectiveness of power plant modernisation projects. Thus it would significantly extend their lifetime and limit the need to incur high costs of building new capacities.

Analysis of the situation in the National Electricity System indicates that guaranteeing an appropriate level of reserve dispatchable capacity is becoming increasingly challenging. For many years the threat of unbalanced demand and supply in the National Electricity System was a purely hypothetical problem for Poland. However, 10<sup>th</sup> of August 2015 has confirmed that in current conditions unfortunately it is a perfectly real problem, and even worse – one that will grow as years go by.

On 10<sup>th</sup> of August 2015 as result of cumulation of many factors adversely influencing the energy security, for the first time in many years Poland had to introduce 20<sup>th</sup> degree of power consumption curbing in its National Electricity System.

### Situation in the National Electricity System on 10<sup>th</sup> of August 2015, 2015 [MW]

PKEE based on data from PSE Operator SA



This situation demonstrated that the National Electricity System is exposed to risk of unbalancing and the available market and regulatory mechanisms are not enough to counter such situations.

2015 was not an exceptional year in this respect. One should remember in particular that domestic generating capacities are subject to natural wear and tear reducing their reliability. New generating capacities will highly likely improve the energy security of Poland, however, only if they will be commissioned according to schedules. Such assumption – as shown by domestic and international experience – may be overly optimistic, and the consequences of such optimism may be a significant risk of disruptions in power supply to end-users.

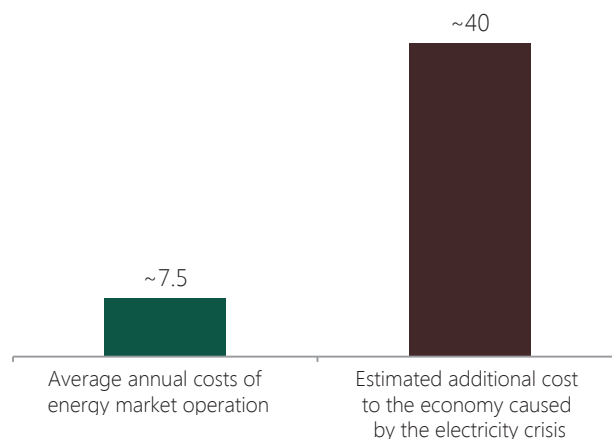
## 1.2. Minimising the cost of energy supply to the end-users

One of the expected results of the capacity market is reduction of cost of energy to end-users. This postulate is to be achieved through:

- Reducing the risk of system unbalancing that generates significant costs to end-users and the economy. Possible limitations of electricity supply adversely impact profitability of businesses, their competitiveness on the international arena and willingness to locate investments in the country concerned
- Reducing the market risk to conventional producers that allows achieving lower cost of debt market financing by guaranteeing stable cash flows
- Stimulating development of the demand side that may actively participate in the capacity market mechanism through taking part in auctions organised by the TSO or effectively manage its electricity demand.

### Annual cost of operation of the electricity market and additional costs borne by the end-users during the California electricity crisis in 2000-2001 [USD billion]

PKEE based on: The California Electricity Crisis: Causes and Policy Options, Christopher Weare, Public Policy Institute of California, 2003



## 1.3. Introducing the tools for fulfilment of the Energy Policy

Capacity market is a tool allowing fulfilment of the goals of the national energy policy, particularly in area of modernisation of existing and construction of new generating capacities, as well as stimulation of development of the DSR. Without introduction of the capacity market, initiating capital intensive investments will become extremely difficult. Assuming continued current low profitability of the sector – it will be virtually impossible.

Introduction of capacity market allows creating conditions allowing for long-term investment decisions to be adopted, by limiting the market risk. At the same time capacity market allows coordination of investment efforts within the National Electricity System and adapting them to actual system needs. This allows avoiding overinvestment and underinvestment situations, as market participants know in advance what investments of key importance to the National Electricity System will be implemented. With improved predictability of the market and stabilisation of revenues the financial institutions will be more willing to provide financing of ambitious investment programmes. It is worth noting that capacity market makes it possible to build new conventional capacities in the “project finance” formula, which is out of question in the current situation. This means that implementing a capacity market brings down some of the market entry barriers and makes the market more competitive.

To improve the functioning of the energy market in Poland we advocate introduction of capacity market in Poland.

Under the proposed solution the current electricity and ancillary services markets should gradually evolve so as to assure security constrained economic dispatch. Evolution of these markets will uncover the value resulting from flexibility of the generating units in responding to demand variations and generation of uncontrollable sources, as well as the value resulting from their location in the power system. These goals may be achieved using a range of means, however one must remember that their implementation is time-consuming and abandoning measures leading to implementation of capacity market is definitely too costly to make today's decisions dependent on distant-future assessment of results of introduction of evolutionary changes in the electricity and ancillary services market.

The second element of changes is the introduction of a market in which the volume of capacity is contracted that is necessary in future to preserve security of supply of electricity and power. The same capacities are used during the product delivery years for system balancing, so the better will the location signal valuation (by appropriate design of ancillary services or nodal pricing) and valuation of flexibility of generation and demand units work on the electricity and ancillary services markets, the more competitive offerings will come up on the capacity market. In particular, should the hypothesis of sufficiency of energy only market (EOM) turn out to be true, the prices on the capacity market should be descending to zero.

In our analysis we also stress that the current temporary solutions supplementing the energy only market (EOM plus), though do not provide the full breadth of social welfare, may be effective in operational capacity provision and securing strategic reserves. We describe the proposal for evolution of their form below.

## 2.1. Improving the functioning of electricity market

In this section we describe the main changes that in our opinion would contribute towards improvement of pricing of flexibility and location of generating sources and demand centres in the National Electricity System.

First of these changes would be the **harmonisation with neighbouring systems**, and ultimately adapting the **price caps in the wholesale market to level resulting from Value of Lost Load (VoLL)**. Current solution consisting of divergent day ahead, balancing and intraday price caps blocks effective development of the demand side, and thus emergence of competition in electricity consumption. Price caps lower than the value of lost load do not encourage demand reductions – as the wholesale prices are then by definition lower than the value of reduction. Limitations in defining the ultimate level may consist of guidelines being an element of the process of creation of the pan-European electricity market – should it be so, care must be taken to assure that the benefits of harmonisation be at least equal to loss of effectiveness of the Polish market.

Along with broader inclusion of DSR in provision of regulation services to the TSO, the change of caps on wholesale prices should result in **stimulation of the demand side**.

Second part of the changes would be **improvement of operation of regulation ancillary services** that, generally speaking, should be supplementing the capacity market through correct valuation of location signals and flexibility of generating units as well as demand side in responding to variations in demand and generation from renewable energy sources. Currently these ancillary services are executed on the technical market intended to assure relevant reliability and quality parameters of electricity supply in individual system nodes. Our proposals supplement and sometimes eliminate elements of specifications of these services with the objective of improvement of cost-effectiveness of assuring secure electricity and capacity supply in the National Electricity System.

Third group of changes would be repairing the elements **we consider dysfunctional in the current mechanisms**. These for example include the issue of **electricity pricing in times of imposed electricity consumption curtailments** (degrees of power supply limitation), where prices drop instead of increasing. In our opinion administrative modification of electricity demand in such case precludes the possibility to reflect scarcity of generating capacities in the National Electricity System in the wholesale price – so the price, just like the demand, should in such instances be also defined administratively. Other issues we raise concern equal access to electricity purchasing – **at present the TSO has preferential, not market-based terms and conditions of energy purchasing** for the needs of inter-operator inter-system exchange, and using the clearing prices defined in the Grid Code the **TSO transfers part of the cost of removing the grid limitations to the electricity producers** (referred to as electricity sales contract reallocation).

In the following part we describe in more detail two elements of market mechanisms that are extremely important in the transitional period: **operating and strategic reserves**.

### 2.1.1. Strategic reserve mechanism

In case of the strategic reserve mechanism, generally known and widely used in global energy industry and in Poland referred to as the Interventional Cold Reserve (ICR) we think it is reasonable to **extend the scope of application of this mechanism to the level of 2.5 GW** resulting from an analysis, i.e. to a volume covering temperature sensitivity of the National Electricity System in winter and in summer.

Provision of the ICR service consists of dispatching and using the generating units of a contractor by the TSO for interventional balancing of active power. The scope of the service includes:

- maintaining generating units in readiness to operate and achieving the active power load level requested by the TSO;
- using the capacity of generating units, consisting of activating the units and feeding the energy generated by these units to the grid in quantity and during the time defined in the TSO's request.

In our opinion the use of ICR in Poland is correct as it avoids disturbing the operation of the wholesale electricity market. At the same time we are of opinion that the tender criteria that limit the bidders to CDGUs that have been granted the right to benefit as of 1 January 2016 from temporary derogation from emission standards on power of the Directive 2010/75/EU of the European Parliament and of the Council should be relaxed by the TSO. This will allow higher competitiveness among the submitted bids and assuring the strategic reserve most effectively from consumer's point of view.

The issue of increasing the ICR volume is even more important as according to the forecasts by the TSO until the end of the decade likelihood of retiring additional generating units will grow and so will the probability of periodic capacity shortages when weather conditions deviate from the climate averages. In case of ICR, which belongs to a class of mechanisms that remunerate for capacity based on strategic reserve, one may utilise the experience gathered as result of broad use of this mechanism in European countries. The low process complexity is also not without importance – such solutions receive positive opinions of the European Commission as the rules of their operation are market-based. The above arguments should be reviewed in the context of high cost of abandoning the energy market reforms referred to in this paper.

### 2.1.2. Operating Capacity Reserve

The objective of the OCR mechanism is to maintain in the National Electricity System the required surplus of generating or reduction capacities above the demand, which under the current specification of this service may be achieved using existing conventional plants, new builds or by demand reduction. We are of opinion that the **price of the operating capacity reserve should depend on the LOLE (Loss Of Load Expectation) and CONE (Cost Of New Entry) market parameters**, meaning in particular a change of price capping in this mechanism from the reference price (hourly operating reserve reference price) to CONE/LOLE. The current solution of maintaining a price cap on reference price level does not provide the market with full information on the market value of the reserve at times of supply scarcity.

In its current form the OCR consists of the following generating capacities of Dispatchable Active Generating Units ( $JG_{wa}$ ) constituting surplus capacity over the energy sales agreements:

- in case of generating unit in operation – spinning reserve in its part not subject to the energy sale agreement or free balancing;
- in case of non operating but dispatchable unit – full dispatchable capacity of this unit.

Under the OCR mechanism the traded and cleared item is the gross dispatchable capacity of the  $JG_{wa}$  involved.

We consider the construction of the mechanism that eliminates duplication of revenues from the energy market and ancillary services as correct. We are also of opinion that the preference for DSR consisting of separate contracting of the demand resources as the negawatt service, and then reduction of demand for the OCR in the volume previously contracted under the negawatt service is justified in the transitional period. Although ultimately there should be no discrimination of generating units with respect to the demand side in contracting, price and clearing; but the present quality deficits in provision of the service by the DSR justify introduction of preferences for this group of service providers in the transitional period until this promising market segment reaches maturity.

When considering the OCR mechanism in international context, to generate appropriate pricing signals some countries are introducing mechanisms allowing continuous pricing of the capacity reserve, allowing real time flexible reactions to demand variations. A example here is the operating reserve demand curve implemented within ERCOT (Texas, the only US market without capacity market) or the mechanism used in Australia. In principle these mechanisms constitute a kind of ancillary service intended to assure appropriate capacity reserve level able to react swiftly (adequacy and flexibility) in emergency situations. Such mechanism underscores the significant role of flexible sources in the system that allow both demand balancing and growth of renewable energy sources, particularly the unstable wind power plants that alone would not be able to operate on the electricity market and to balance the demand on part of end-users.

To achieve realistic pricing of the operating reserve we propose implementation of the OCR clearing model **by introduction of annual OCR budget cap not exceeding the cost of construction and operation of OCGT sources** that currently are the cheapest alternative for maintaining reserves in existing coal-fired sources.

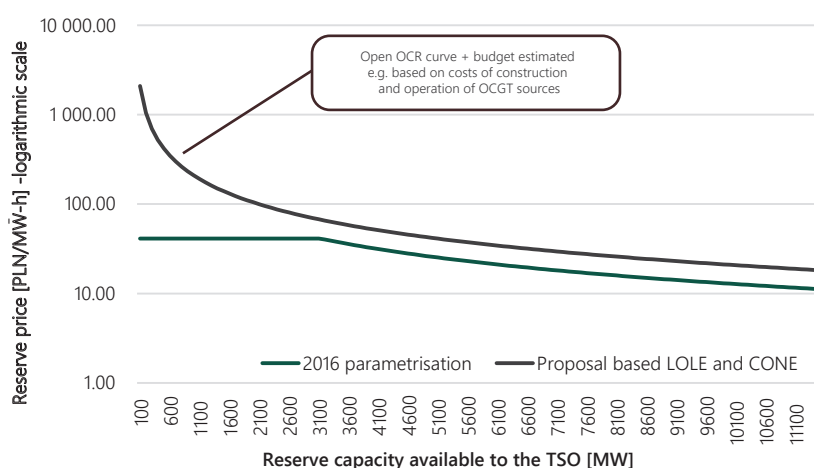
Such a change would also mean a redefinition of the current level of the hourly operating reserve reference price and its replacement with the value of CONE/LOLE, and replacement of the reference reserve capacity volume according to the statistical approach to capacity reserve determination described in this report.

Justification for introduction of OCR budget cap based on the cost of construction and operation of OCGT technologies, including fixed and variable costs of purchases and supply of gas fuel, lies in the fact that currently it is the lowest cost alternative way to assure the required level of reserves for the TSO. Under such solution the OCR budget should be reviewed annually with respect to the statistical level of the required reserve capacity forecasted by the TSO and costs of building and operating OCGT sources.

The clearing process of the operating capacity reserve (determination of unit price and volume) in our opinion could continue according to the current principles.

## Proposed modification of the Operating Capacity Reserve- current situation and the proposed solution

PKEE analysis

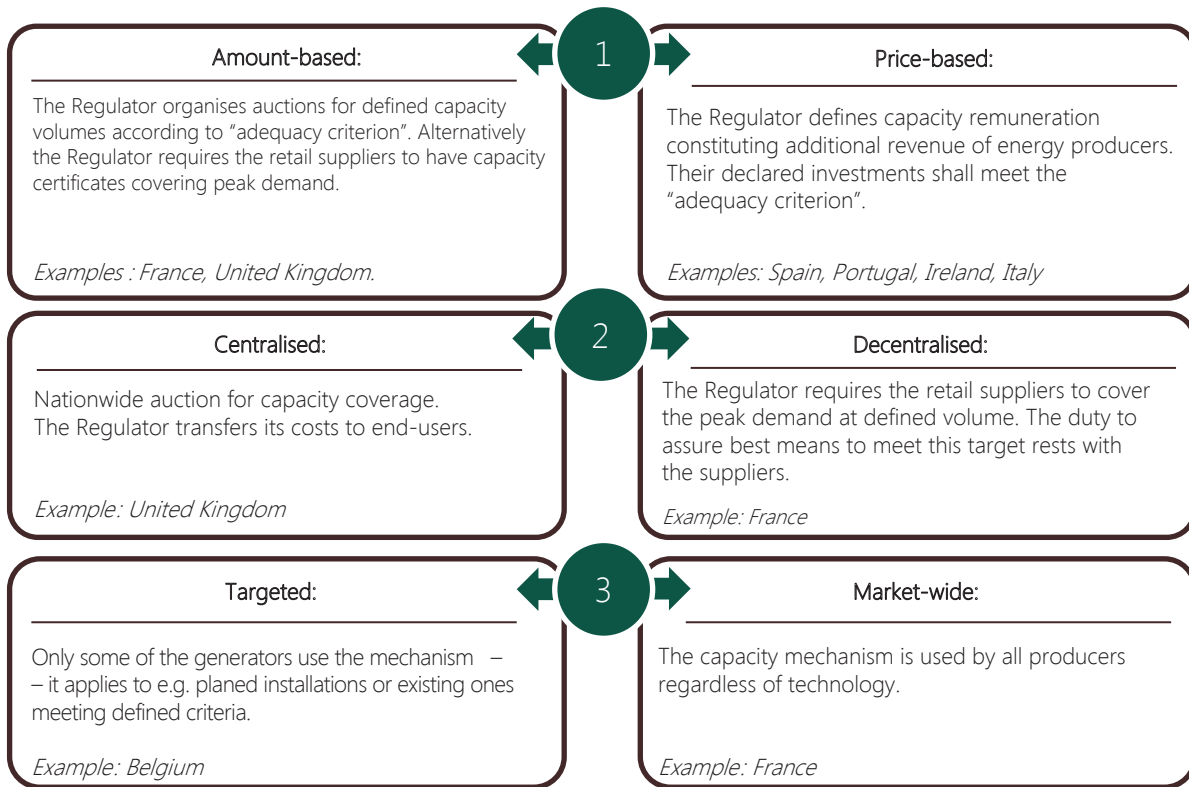




## 2.2. The ultimate mechanism

Analyses of capacity markets and mechanisms conducted by the European Commission most often employ the mode of operation based taxonomy. Consideration is given to what entities set out the volume of generating capacity and what entities are under purchase obligation and in what volume.

### Typology of capacity markets



Considering the nature of problems identified, chiefly including the lack of possibility of balancing the capacity demand in the Polish power system in all time horizons, **we recommend introducing centralised auctions for generating capacities along with the energy market and ancillary services reform.** This is a solution that has practically proven its cost effectiveness in assuring the required system operation security standard in many markets, among others PJM (the largest US market with capacity mechanism based on nodal pricing), New York ISO, ISO-New England. At present such a solution has been implemented also in the UK, however due to numerous amendments introduced to the original mechanism as a result of consultations with the European Commission, it is not yet certain what will be its effectiveness.

The key objective of the energy market reform in Poland should be assuring adequate dispatchable capacity in the National Electricity System. The power supply security standard level may be set both deterministically and stochastically. When designing a new mechanism both these methods should be used at the outset, allowing validation of results of the stochastic approach by the deterministic method better known in Poland. Ultimately, due to decrease of predictability of load on controllable sources caused by wind and photovoltaics generation, stochastic metrics should be used:



- **LOLE** (Loss Of Load Expectation) – already described metric meaning the expected number of events consisting of administrative curtailment of electricity consumption over a defined period, most often a year.
- **LOLP** (Loss Of Load Probability) – probability that during a given period (year) an administrative curtailment of electricity consumption will occur.
- **LOLH** (Loss Of Load Hours) – expected number of hours of administrative curtailment of electricity consumption.
- **EENS** (Expected Energy Not Served) – expected value of lost electricity consumption by end-users as a result of administrative curtailment of electricity consumption.

All the above metrics are tightly interrelated and from practical perspective it is important that consumers shall be able to intuitively interpret the adopted standard. In fact the consumers are represented by the TSO in energy purchases, but should be aware of what they are receiving in return for the funds the TSO spends on their behalf on energy purchases.

Moreover it should be assumed that the capacity mechanism implemented in Poland will be reviewed for existence of state aid. To minimise the risk of it being considered an inadmissible state aid we recommend following the guidelines of the European Commission and practices, e.g. in notification of mechanisms introduced in the UK, however avoiding the mistakes made there.

The key issues to be considered when implementing the proposed mechanism are presented below.

### 2.2.1 Electricity system reliability standards

The key determinant of reliability of any electricity system is the adequate installed capacity. It allows balancing and maintaining appropriate capacity reserve. Every TSO is required to assure electricity supply reliability through, among others, maintaining and developing grid infrastructure and planning system operation on basis of historical data, demand forecasts, data on existing and planned generating units, etc.

There are many methods of assessing reliability of power systems and reliability factors used throughout the world. However, dynamic growth of renewable energy sources and drop of investments in conventional sources (combined with gradual retirement of “old” units) results in necessity to modify the concept of system reliability planning.

The deterministic approach to system planning and defining reliability criteria used since many years (maintaining “rigid” capacity reserve as percentage of peak demand, N-1 criterion, Worst Case Condition, etc.) is in recent years being successfully replaced by probabilistic approach that allows inclusion the stochastic factors in the planning process. Probabilistic models allow ongoing analyses of multiple diverse variables and are capable of generating multiple scenarios.

At present the key metric of electricity supply security assessment in many countries (e.g. Germany, Netherlands, Belgium, France, UK, USA) is the LOLE factor (Loss of Load Expectation) defined as average number of days/hours over a defined period during which the electricity supply may be expected not to meet the demand. It should be noted however that LOLE is not the measure of number of days/hours in which blackouts are to be expected, but during which the system operator may be forced to utilise the available remediation tools, and controlled load shedding will be an extreme move when all remediation measures shall be exhausted.

As the share of renewable energy sources in the European electricity systems is significantly increasing while their generation depends on weather conditions, LOLE is an extremely important metric. In fact it reflects the negative impact of uncontrollable generation from these sources on system reliability.

The maximum acceptable level of LOLE is used as a criterion of electricity system reliability – the LOLE Standard.

	Germany	France	UK	Netherlands	Belgium	Ireland	USA (NERC standard)
LOLE Standard [h/y]	3	3	3	4	2.5	8	2.4

LOLE Standard is typically based on macroeconomic premises including the influence of potential outages on the economy and on the society, and on comparison of these costs with the costs of investing in additional generating capacities.

Advanced mathematical models simulating the operation of the electricity system determine the LOLE for an assumed period and assumed scenario. The LOLE level determined by the mathematical model for a given period provides information to the system operator about the forecasted reliability of the system in that period and about the capacity reserve volume the operator should plan for. Moreover, the models determine several additional reliability factors such as LOLP (Loss Of Load Probability), LOEE (Loss of Energy Expectation), EEU (Expected Energy Unserved).

Based on the available information and analysed literature it seems that the recommended value of security factor for the Polish National Electricity System is  $LOLE=3$ , as is reflected in the modelling assumptions adopted for the purpose of preparation of this report. In the event of higher forecasted load at 10.15 GW, to adapt the system to the reliability standard the operator must assume introducing new generating capacities to the system of minimum 150 MW effectively.

Growing share of uncontrollable and highly unpredictable renewable energy sources in the European electricity systems causes the factors based on deterministic models to become inadequate for assessment of reliability of systems in contemporary markets. More effective tools for planning the operation of power systems in such conditions seem to be the probabilistic models and reliability standards based on the LOLE factor.

### 2.2.2. The capacity market product

The basic product of the ultimate capacity mechanism should in an optimal way – from the market, technical and cost point of view – assure medium- and long-term security of electricity supply in the National Electricity System, while at the same time considering non-discriminatory market access principles.

Definition of the capacity market product shall at the same time be an incentive for investment and modernisation decisions concerning existing generating units, as well as for development of broad range of demand side response/management mechanisms.

The main product of the capacity market shall be supply of net dispatchable capacity by generation or by reduction, supplied by the producer or consumer respectively in a given period of peak load of the National Electricity System, when there is a real danger of inability to meet the demand. The guaranteed obligation of energy producer or consumer should be subject to bilateral but standardised capacity agreement with the single user of the service being the TSO purchasing capacity on behalf and for the benefit of all users connected to the National Power System.

The agreements should cover futures contracts with physical electricity delivery or physical load curtailment. Long-term capacity contracts generating additional revenue streams should allow recovery of fixed costs and at the same time would not be impacting the current operation of the energy market on principles of recovery of exclusively the variable costs, safe for the National Electricity System.

The product consisting of electricity delivery or load reduction should take into account the predictability, stability and technical aspects of contract fulfilment, such as for example the speed of commencement of delivery, or dispatchability /reliability of electricity supplying equipment. Offering the capacity product should not be limited only to currently dominating conventional technologies, allowing full and nondiscriminating participation of other electricity supply and load reduction technologies within the National Power System, in line with the technology neutrality principle.

The definition of the product being delivered should be uniform or, if derogations from this principle are practiced, assessment of the volume and value of the service should be the same regardless of what technology is pricing the product according to varying specifications.

### 2.2.2. Economic principles of designing the mechanism

In subsequent description of solutions the capacity market will be treated as a mechanism constructing the function of exchange of utility between market participants, intended to **minimise the cost of running the system** and preserving limitations of:

1. **Individual rationality:** no market participant may be at a loss as a result of its participation in the mechanism. This applies both to electricity producers who should not be keeping unprofitable generating plants in the market, and consumers – who should not be paying for energy security more than they would be when using the alternative of assuring their own energy supply (autogeneration or own DSR offering) or in centralised CONE (Cost of New Entry) capacity market.

2. **Budget balance:** the sum of payments to the capacity market by consumers is at least equal to the payments to the entities providing the capacity supply service. This standard restriction in design of every mechanism contains the term “at least” as similarly to other products; also the capacity product will be subject to taxation.

3. **Truthfulness and directness:** market participants should not be disclosing as a result of operation of the mechanism their true valuation of the capacity product. In particular the mechanism should not encourage its participants to construct intermediate steps in form of strategies allowing change of the market result into another with respect to the optimal one.

### 2.2.3. Auction format

When designing the capacity mechanism, assuming selection of a market-wide, centralised auction mechanism, there are many elements of the mechanism to be taken into account.

One of the first auctioning parameters to be decided upon is the selection of discriminatory-price (pay-as-bid) or uniform-price (pay-as-clear) auction. This selection is performed on many markets and was also tested many times on the energy market. Ultimately, in case of electricity auctions, clear global preference went to the **uniform-price auction mechanism**. There are three interrelated underlying reasons:

- Discriminatory auctions stimulate shadow bidding on part of bidders trying to maximise revenues. In other words, due to incomplete information about the game individual market participants will be trying to guess what may be the outcome and inflate their bids with a margin. This causes unnecessary disturbance of directness of the mechanism and higher uncertainty both in the context of price and the allocated volume. However, the strategy in a uniform-price auction is straightforward and consists of submitting bids based on real individual costs and treating a higher outcome of the auction as an additional return resulting from high cost-effectiveness of one's project.
- Due to complication of bidding strategies in the discriminatory option, it typically results in loss of social welfare consisting of allocation of purchased volume not to lowest cost bids but to lowest price bids. Despite a slight probability that the bidders will maintain cost monotonicity despite lack of coordination of price bids, typically (even with the same costs to consumers) there will be a loss of producer surplus.
- The discriminatory auctions are more prone to the “winner's curse” consisting of underestimation of costs by the bidding market participants. This common phenomenon intensifies along with:
  - o Increase of disproportion in information in possession of market participants, influencing the price level of the bid,
  - o Increase in the number of bidders,
  - o Level of uncertainty of future costs and revenues.

Although it should be expected that the number of players in both formats will be similar, a multi-commodity uniform-price auction to a large extent eliminates the effect of disproportion in information in possession of the bidders (as the bids primarily depend on individual costs, and not the expectations of behaviours of other market participants), thus at the same time causing reduction of the uncertainty level.

From a practical perspective this means that in case of a uniform-price auction one should expect a higher social welfare and lower risk of a bidder withdrawing from an underpriced bid – and thus higher certainty of capacity supply.

It is worth noting the wording that in case of uniform-price auctions the bids depend “primarily” on individual costs of the bidder. This wording refers to selection of first-price or second-price auction. The literature and practice indicate that the **optimum choice is the second-price auction** that allows elimination of the “primarily” wording and thus further improvement of the effectiveness of the mechanism. It happens so as in second-price auction there is no bidder motivation to submit bids other than based on own real costs – then it is a bidding strategy that is a Nash equilibrium. Such choice will however be incompatible with some forms of auctioning – for example the Dutch auctions.

The second important choice to be made is whether a multi-commodity uniform-price and second-price auction should also be an open or sealed-bid auction. In this case the choice is less straightforward. Using the analogy of electricity supply on spot markets it becomes clear that the dominating model is disclosure of the bids. An important aspect differentiating the capacity auctions from Day Ahead Market (DAM) auctions is their repeatability however, which in case of DAM allows intensification of competition in the battle for sales volume (the merit order effect). Lack of this repeatability causes that in case of capacity auctions the intensification of competition may not happen. Therefore for the initial period **it is recommended to disclose the bids ex post**, and not during the auction. The ultimate model should be the more transparent open-bids mechanism.

Such a solution preserves the possibility for consumers to validate the cost effectiveness and appropriateness of the algorithm of purchasing capacity on their behalf while at the same time helps in avoiding the potentially unpredictable behaviours of market participants.

The third choice is the decision on the form of holding the uniform-price, multi-commodity second-price auction with sealed bids. Practice and literature provide many possibilities in this area, with dominant choices going for fixed price format auctions or Dutch auctions. Both these solutions have their advantages and disadvantages.

The fix format consists of all bidders submitting complete and comprehensive bids that then are sorted by ascending bid prices. Such format may fully utilise the possibilities of second-price auction mechanism, a strong advantage as market participants state true costs for submitted bids. It also allows selection of the (not recommended) discriminatory auction option. On the other hand the fix format's drawback is the inability of market participants to adjust to prices offered by other bidders.

The Dutch format consists of progressive decrease of the auction price until the supply and demand become balanced. As opposed to fix format, it does not allow for easy use of second-price auctions or (not recommended) discriminatory auctions. The first element, even though to a small extent, will lead to decrease of social welfare as a result of complication of the way capacity suppliers submit bids. A drawback of such solution is also the lack of possibility to know the bids even ex ante by most investors whose capacity sale bids were accepted, so it will not be possible to know the cost of assuring energy security at lower requirements as to the level of peak dispatchable capacity in the system. However, at the same time this format has one advantage: it allows matching the prices of other bidders in cases of high uncertainty. In the initial period of capacity market operation this advantage tips the scales and although the ultimate mechanism should be fixing, **at the outset the capacity market should be based on Dutch auctions.**

## 2.2.4. Auction variables and parameters

Besides the key elements defining the format of an auction there are also several parameters influencing the effectiveness of the mechanism by introducing limitations or preferences for auction participants and by allocation of risk.

### 2.2.4.1 Centralisation of capacity procurement

First of the important issues is why centralise capacity procurement instead of leaving it to market participants?

The root cause of this problem is the drawback of electricity demand, namely lack of responsiveness of electricity consumers to pricing signals (competition in consumption) as well as lack of effective ability to exclude consumption by those users for whom the pricing would be too high. Because of these two issues **electricity has traits of a public good not a private one.**

The above drawback could be eliminated on majority of other markets through immediate boost of supply or by allowing storage. However, neither of these solutions works on the electricity market as construction of sources of supply takes at least several years and electricity storage is possible only in indirect forms (chemical – batteries, potential – peak pumped-storage, kinetic – flywheels, etc.) and expensive.

It is also possible, at least theoretically, to develop a mechanism that would allow optimisation of the level of reserves by investors. Although this would require the state to abandon its control over energy supply security and hand it over to the market, but such an option should be given at least a theoretical consideration. It would mean that the market optimises the volume of energy not served so that the marginal costs of administrative supply limitations would be equal to the marginal costs of maintaining the generating units in reserve and commercial reductions of demand by other consumers. There is however a clear problem in such approach – in the event of brownout or blackout the market would stop functioning. In case of blackout there simply is no price nor sales volume that would allow transmission of a price signal to capacity suppliers. Similar effect, though in a smaller scale, may be seen also in case of brownout. Administrative limitation of power consumption in Poland on 10<sup>th</sup> of August 2015 led to a decrease (!) instead of increase of electricity prices. However, it is a response adequate to the current market mechanisms – administrative curtailment caused drop in demand for electricity on the market and thus a drop in its prices. But it was not a correct effect as the electricity price was not reflecting the consumer's willingness to consume it. So also in this case the market stopped functioning. In summary, **the level of capacity reserves may not be optimised by the market alone in absence of centralised capacity pricing.**

### 2.2.4.2 Technology neutrality and risk allocation

The second key issue is technology neutrality of capacity market. Such postulate, using the language of operational research, will allow for removal of constraints of the problem and additional elements influencing the goal function that would raise the minimum necessary cost of the capacity market. In particular initiatives like division into auction baskets, elimination of selected technologies from competing (DSR, cogeneration), separate definition of capacity product and the like will definitely significantly increase the cost of the capacity market. **A particular type of technology discrimination concerns also the lead time** of capacity purchasing – short lead times may eliminate participation of investors interested in bidding long construction lead time sources (e.g. coal based).



It is worth noting that the main value added by the capacity market is lowering the risk, thus many aspects of the capacity market must be assessed from the point of view of appropriate allocation of risks between market participants. For example, to reduce the risk of incorrectly forecasting peak demand the TSO may decide to split the capacity volume purchases into periods with long advance (T-6 – T-8 years) and short advance (T-1). It should be noted that the risk of incorrect forecast does not disappear itself – just its allocation to investors changes and they are not sure if and what purchasing volume they may expect in the T-1 period.

On the other hand, there is a risk of moral hazard appearing in the capacity mechanism, consisting of attempts to submit opportunistic capacity bids counting on – for example – drop of technology costs in future or on unthorough/non-physical/declarative verification of the service provided. Such bids, despite winning the auction, may not provide the service in the delivery year. Since avoiding load shedding requires services of all contracted suppliers, a drop out of even a single opportunistic bidder will result in potential problems in the supply year. Risk mitigation methods in such case should be focused on investors and implement **severe penalties for culpable failure to deliver capacity** as well as certification and validation of provision of capacity services.

There is also a special case of neutrality assumption consisting of entering into contracts longer than for one year. It concerns primarily new builds and modernisations of existing installations that for purpose of risk reduction require forecasts of stable revenues in multiple future periods. In such case consideration should be given to **reallocation of risk of regulatory changes on capacity market (or its termination) to the creators of such regulations**. Allowing entry into longer term contracts allows less expensive contracting in the new build capacity market.

**Risk of delay of investment completion** has a natural owner, the investor. Ways of its mitigation should thus be focused on appropriate motivations for investors, for example:

- lack of revenues in the year of delay of investment,
- shorter effective duration of remuneration from the capacity market,
- additional penalties for failure to meet the obligation.

Any means of mitigation that motivate investors cause increase of capacity market costs, at the same time increasing the credibility of bids submitted at auctions. Realistically one should not expect 100% effectiveness of motivation measures consisting of penalising the investors for wrong decisions. Therefore, to provide delivery of appropriate capacity in the delivery year the plan for auction based capacity volume purchasing shall assume a buffer for this risk.

Reduction of effects of materialisation of this risk should thus involve the measures in disposal of the TSO, such as:

- purchasing a capacity buffer to cover the risk of lack of supplies from new builds,
- certification, monitoring and application of penalties during investment construction,
- ability to purchase additional capacity after the primary auction to fill in the identified dropouts.

**Risk of failures of generating and demand units**, similarly to the risk above, is to a large extent owned by the investor. It is worth noting that wrong design of penalties may cause both (a) moral hazard of opportunistic capacity bidding to get reward with luck of no significant failures in a given year and (b) conservative bidding of low availability capacities when penalties will be high or asymmetric with respect to the premium for exceeding the tendered availability.



Besides the tools referred to so far the investors may achieve mitigation of the financial risk in this case through:

- modernisation investments and preventive overhauls at times of no capacity shortage risk,
- offering capacity adjusted with higher/lower availability factor (depending on the penalty/premium structure).

Moreover, to assure physical delivery of capacity to the system, the TSO has to determine the capacity purchase volume taking into account the stochastic nature of faults.

This risk appears in a particular manner on the demand side that offers demand reduction. When the penalty will be capped to annual revenue from capacity market, then for every consumer connected to the National Electricity System it will make sense to offer reduction capacity even if he has no intention to ever physically provide these reductions. It will happen, as a consumer submitting reduction bid can never lose and may (with a non zero probability) gain additional revenue. Wrong design of the way of verifying the demand reduction may also allow opportunistic clearing of reductions actually performed by the DSR aggregators – part of the portfolio of aggregated consumers will typically contain consumers that have anyway planned breaks in electricity consumption, and they will be billed to the TSO as performance of the obligation (the non-coincident consumption effect).

**The risk of error in forecasting peak demand at the capacity auction** has the natural owner – the TSO. TSO has the following risk-mitigation tools:

- transferring the risk to investors by auctioning only the part of volume with long lead time, and part just before the delivery period,
- setting the capacity purchasing volume that takes into account the possible demand forecast errors (robust/stochastic/chance-constrained programming).

It is worth noting that if the design of the method used by the TSO for verification of energy supply obligation fulfilment will include dependency on the volume ordered by the TSO on auction and the level of energy supply obligation fulfilment, then the financial risk of erroneous demand forecast by the TSO is transferred to investors.

**Risk of Force Majeure**, similarly to the demand forecasting error risk, shall also be managed by the TSO. There are many reasons for centralising the risk of occurrence of Force Majeure, notably:

- object of insurance – Force Majeure risk – insurers charge very high premiums, so it will also be transferred to consumers as higher capacity market prices,
- incidents of lack of availability as result of Force Majeure operation typically are of binary nature (total capacity loss, e.g. generating unit outage), and binary risks are expensive to protect against,
- risk is correlated between market participants (e.g. flood or natural disaster lowering the level of rivers and consisting of extreme heat waves) – marginalising the risk mitigation potential consisting of exchange of the capacity merchandise between market participants not affected by Force Majeure.

It is worth noting that even if the capacity suppliers affected by Force Majeure pay financial penalties, it still does not solve the problem of lack of energy supplies to the system as a result of this Force – thus motivational penalties on investors will have a limited effectiveness.

However the TSO has at its disposal a tool consisting of determining the capacity purchase volume that takes into account the incidents resulting out of materialisation of the risk of Force Majeure, which seems to be the most adequate in mitigation of physical consequences of risk materialisation.

Another type of risk belonging to financial risks category is the capacity market financing credit risk. Centralised capacity purchasing means lack of possibility of selection of trading partner by both sides, meaning that the credit risk liability should also be transferred. In particular if the fees are collected by the DSOs, then their financial liquidity should suffer as result of capacity payments. The TSO here has a tool consisting of appointment of an entity responsible for settlements that would perform payments to capacity market service providers despite credit incidents on part of consumers.

The above examples do not exhaust the list of risk related issues that need to be addressed when designing the capacity mechanism; however we do hope that they will be an encouragement for adopting orderly approach in this aspect.

### **2.2.5. Secondary trading in capacity product and internal balancing**

To mitigate the risk of capacity supply non-performance, a very important element of the capacity market should be the establishment of an integrated secondary market for trading in capacity agreements. The subject of trade should be the physical contracts transferring the rights and obligations resulting from the capacity agreement entered into with the TSO. Parties to the contracts should only be entities that have been verified and allowed to participate in the capacity market in the specific period.

Contract specification should provide for the possibility of selling both the whole and part of the capacity volume and allow division of the period of providing the capacity obligation. It seems desirable for the secondary capacity market to be operated on regulated trading platforms tightly interconnected with a central register of capacity supply contracts maintained by the TSO recording transfers of rights and obligations.

The final approval of transfer of rights and obligations arising out of capacity agreement sold on the secondary market should not take place earlier than upon establishment of a record in the central register of capacity market maintained by the TSO. The TSO should without delay transmit information about any and all changes to entries in the register to the parties concerned. Secondary trading in a given period should be conducted only upon signing the agreement and entry into the register resulting from termination of primary trading.

The TSO should operate a central database of entities participating in the capacity market and publicly disclose information about aggregated volumes of available contracted generating and reduction capacities for individual periods – based on current entries in the central capacity register.

To further mitigate the risk of capacity supply non-performance, besides the ex-ante secondary trading consideration should be given to introduction of ex-post secondary trading resulting out of existing surpluses and deficits of capacity supply by individual entities. Such trade should work on principle of independent balancing among the suppliers before final clearing with the buyer (the TSO). The ex-post trading should also take place on regulated trading platforms, just like the ex-ante secondary market.

The final stage of clearing should consist of the TSO's verification of obligation fulfilment by the supplier. Underperformance should result in a fine being imposed on the supplier, clearly defined at the moment of submission of bid on the capacity market.

### **2.2.6. Method of transferring the capacity payments to end-users**

The capacity contracting costs borne by the TSO should be transferred to end-users who should be paying a capacity fee.

The TSO would be calculating the capacity fee rates for end-users whose installations are connected to the transmission and distribution grids. The former would be paying the capacity fee directly to the TSO, the latter via the Distribution System Operator (DSO). The rates would be defined in PLN/MW/month. The capacity fee rates would be subject to approval by the President of the Energy Regulatory Office according to standard tariff approval procedures or would result from predefined rules; however the process monitoring would remain with the President of the ERO.

The capacity fee driver is the ordered capacity specified in the transmission contract of the end-user. In transition period standard ordered capacities should be defined for household customers. Standard ordered capacities would be defined for three groups. For practical reasons it makes sense to adapt the same consumption bands as currently used for the competitive transition charge - this will significantly simplify its implementation in IT systems (low implementation costs due to the same principles used). Ultimately the clearing of capacity supplies may be based on the maximum capacity demand by a given consumer during peaks in the National Electricity System or in other tight balancing periods in the System.

Bearing in mind the current market situation it makes sense to introduce hourly-metering capacity payments only for customers with ordered capacity in excess of 40 kW with installed metering equipment allowing data transmission (possibly with a transition period for installation of metering systems at such customers). A natural solution seems to be the clearing of capacity rate between the TSO and the DSO just like in case of the RES charge, i.e. the issuer of invoice to the customer accrues the fees and transfers the fees due minus irrecoverable amounts to the TSO, but without transferring the detailed metering data to the TSO.

Other solutions would require very far-reaching changes in the existing IT systems, including rip and replace, resulting in significant costs to be borne.

### **2.2.7. Inter-system exchange**

When developing rules and regulations governing the capacity market mechanism operation it is extremely important to follow the economic premises common to all Member States of the European Union.

The "Guidelines on State Aid for Environmental Protection and Energy 2014-2020" published by the European Commission in 2014 clearly indicate that solutions such as the DSR or use of interconnection capacity should be an alternative to new builds of conventional capacities as means of assuring generation adequacy in the system. Similar opinion on contribution of interconnectors to the capacity market mechanisms is voiced in another European Commission's document - "Generation Adequacy in the internal electricity market - guidance on public interventions".

The specialist literature points to several differing models describing the use of cross-border transmission capacities in the capacity market mechanisms.

## Interconnectors vs. the power market

1	2	3	4	5
No contribution	Statistical contribution	Interconnector participation	Foreign Capacity participation	Cross-border capacity mechanisms
Neither interconnectors nor foreign providers contribute	Contribution evaluated statistically and deducted from capacity target (but not included in formal mechanism)	Interconnector participates directly in capacity mechanism	Foreign capacity providers participate directly in capacity mechanism	Capacity mechanisms cover several zones OR national capacity mechanisms are „coupled“

The first model (1) **completely abandons interconnector contribution**. For reasons of this solution being far from optimal as demonstrated in analyses conducted by PKEE and its incompatibility with the EU regulations, this model should be rejected.

Another model (2) easy to design and implement is the one **where interconnectors as elements of the capacity market mechanisms do not appear physically in the market but only provide indirect statistical contribution**. Their contribution boils down to setting desired statistical share of available import capacity in the total demand, and then reducing the required capacity to be contracted on the capacity market by this amount. In this operating scheme the interconnectors do not get paid, however bearing in mind that currently construction of new interconnections is anyway provided for by the TSO through socialisation of these expenses, this does not seem to be an important obstacle in achieving competitive situation on the capacity market.

Another model (3) employed in the UK is **full direct participation of cross-border connections in the capacity market mechanisms**. In this case the interconnectors receive remuneration resulting from their ability to physically connect markets with capacity shortages and surplus (or using incomplete coincidence of reserve capacity minimums in different systems). In this model the key role is played by interconnector operators controlling the physical flows. This model due to practical aspects consisting of (a) inconsistency of physical control over energy flows between systems with maximisation of electricity market effectiveness, and (b) lack of realistic perspective of implementation of commercial cross-border connections in Poland by entities other than the TSO; seems to be only of theoretical interest.

Model (4) **allowing access to domestic capacity market mechanism by all foreign generating entities in a scale not exceeding the capacity of inter-system connections has two options**. One assumes auctioning the transmission capacity that would have to be booked by operators of foreign power plants to later submit the bid on the capacity market of another country. The second assumes “free of charge” use of cross-border connections by power plant operators, effectively meaning using the infrastructure paid for with transmission fees by electricity consumers. As much as the second option is incorrect as it does not stimulate development of interconnectors and allows opportunistic bidding on other country’s capacity market, the first model is interesting on

condition of meeting the physical criteria of electricity delivery to the market concerned. Examples of issues that need to be solved before implementation of this option are elaboration of regulations and technical solutions addressing problems with using interconnectors for unplanned energy transmissions (e.g. carousel flows) or governing conditions guaranteeing access to cross-border connections and capacities in events of simultaneous threat to supply adequacy in both electricity systems.

The final model (5) **is synchronised implementation of capacity markets**. In this case the capacity auctions may utilise the well known implicit auctioning mechanism used on electricity markets. The key criterion in this case is assuring consistency of legal regulations describing solidarity based operation of capacity market mechanisms between neighbouring countries, so that neither experiences excessive or insufficient investment in new generating capacities.

Unfortunately in the current regulatory situation the conclusion is that many of the problems applicable to models (4) and (5) should find solutions at the European Union level, and until then the only usable option is the **statistical participation of electricity transmission capacities in the capacity market**. Such opinion is even more appropriate in the context of high costs of forsaking the decision on introduction of the capacity market.

### 2.2.8 Demand side participation

We firmly stand by the opinion that **admitting the DSR mechanisms to the capacity market is a move at least neutral and most probably beneficial for achieving the minimum cost of assuring capacity in the National Electricity System**. In our opinion a good design of the capacity mechanisms may lead to dynamic development of the DSR, initially in the largest and large enterprises sector, and then as smart grid technology becomes commonplace, also among the smaller consumers via DSR aggregators.

Demand Side Response (DSR) consisting of possibility to temporarily decrease the demand for electricity drawn from the system became an important element of the electricity market and its significance will be increasing in the coming years. DSR is a quick and environmentally friendly mechanism of obtaining capacity reserves and flexibility, even if its use is the most expensive available solution. In majority of the European countries consumers declaring readiness to reduce their energy consumption may participate in the wholesale, balancing and strategic reserve market. However, the actual development of the DSR in these countries may be assured by their participation in the capacity market. Experience of the American markets where the DSR is used since many years already shows that around 95% of revenue from this business comes from capacity market programmes. Even if there are differences of opinion concerning cost effectiveness of the DSR in supplying capacity reserves, one should assume that even just the information about the level of cost the users would have to incur to assure themselves the capacity booking service is valuable in itself.

In the UK customers providing the DSR service participate in the T4 auction (four years ahead of delivery) however the term of the futures contracts has been limited to one year (in case of new build generating capacity it is 15 years). Consumers offering DSR may participate in the T1 auction a year ahead of delivery. A programme was also introduced supporting creation of new availability of DSR capacities in form of TA (Transitional Arrangements) auctions for the delivery period preceding operation of the capacity market, from 2016 to 2018. Participation in this programme will exclude participation in T4 auction.

In France the DSR may select among two forms of capacity market participation. DSR participation may be effected by submitting a joint bid with a producer, thus limiting the obligation of a power station or take place directly upon completion of the certification process. The certification process for DSR customers is more lax than in case of generating sources and is required a year before the year of commencement of service provision, as opposed to three-year certification of traditional generation. Such solution accommodates customer requirements for flexible reactions to their growth plans.

Also the practical aspect is not without importance: **inclusion of the DSR in the capacity market should not extend its implementation process** and equal treatment of users and supporting their participation in all electricity and ancillary services markets is a requirement put forward by the European Commission and organisations of regulators.

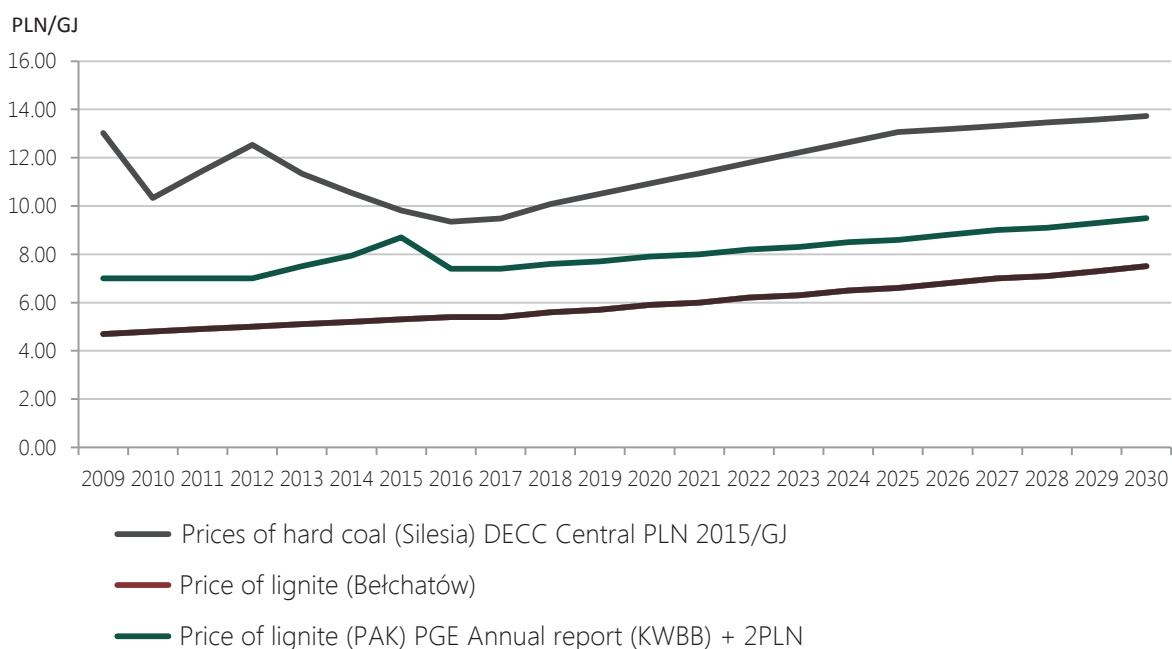
### 3.1. Key assumptions for the analysis

The algorithm of economic distribution of burden assuming minimisation of the cost function requires detailed parameterisation and agreeing the assumptions for the calculations. For this purpose the PKEE team has developed assumptions beyond the horizon of analyses, assuming the ultimate perspective of 2050. This report covers the 2030 horizon, whereas two decades – 2030-2050 – were modelled to avoid the “end of the world” phenomenon – i.e. failure to implement investments (in the model) due to a short term over which such investment may achieve returns on investment. Concerning data validation, public sources were preferred; in case of data with different granularity than required for the model, inter- or extrapolation was applied. Depending on nature of the data a linear or nonlinear approach was used as appropriate.

The following sections of the report illustrate the assumptions adopted for the key parameters of the model and the results obtained.

#### Hard coal and lignite prices

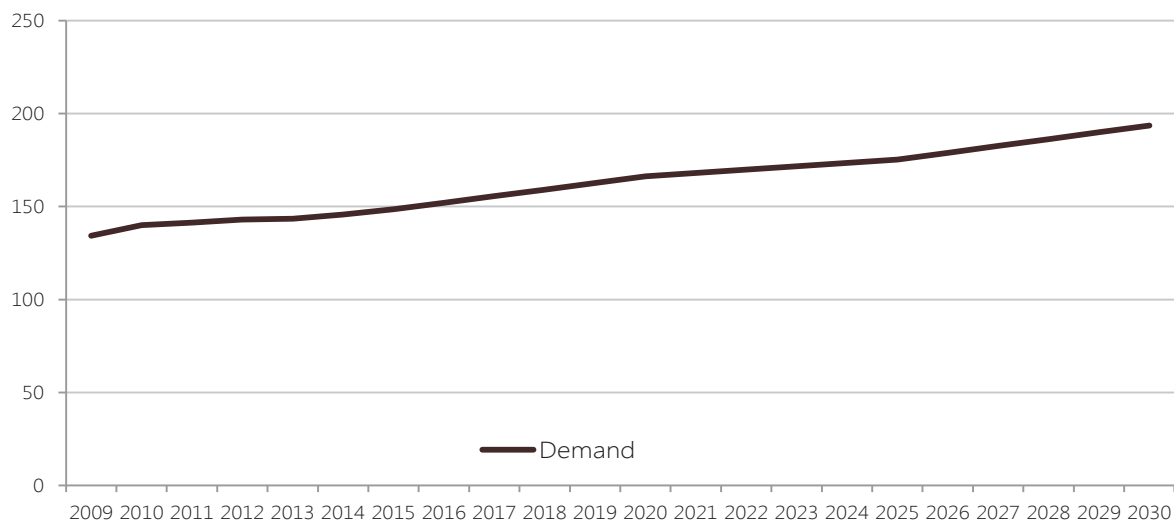
PKEE based on DECC reports and stock exchange regulatory filings



Hard coal prices for 2016-2030 have been standardised for all power plants and adopted according to DECC\* Central PLN2015/GJ assumptions. Lignite price for units in Bełchatów, Turów and generic units was standardised and adopted according to the annual report of PGE KWB Bełchatów. Prices of lignite at PAK for 2016-2050 were adopted according to annual report of PGE KWB Bełchatów plus a fixed value of PLN2/GJ. Prices for 2009-2015 are historical prices derived on basis of ZE PAK stock exchange regulatory filings, thus differences are visible in this period with respect to the 2016-2030 curve.

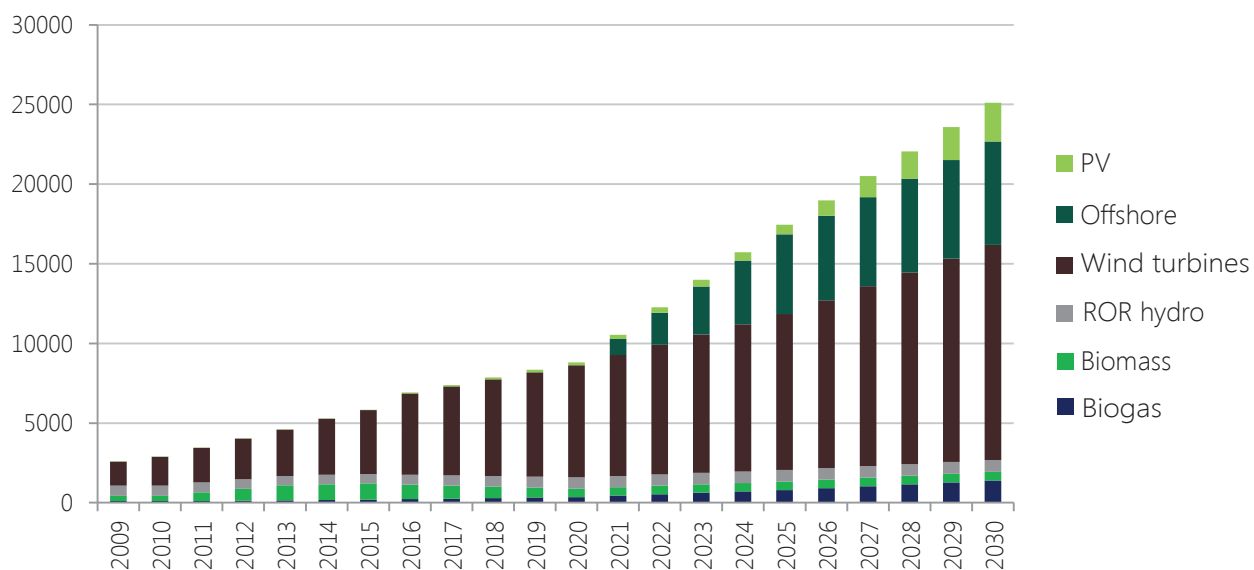
## Electricity demand [TWh, net]

The demand curve for 2016-2030 was developed according to KAPE 2050 (Krajowa Agencja Poszanowania Energii S.A. – the Polish National Energy Conservation Agency). Values for 2009-2015 are actual values.



## RES generating capacity [MW]

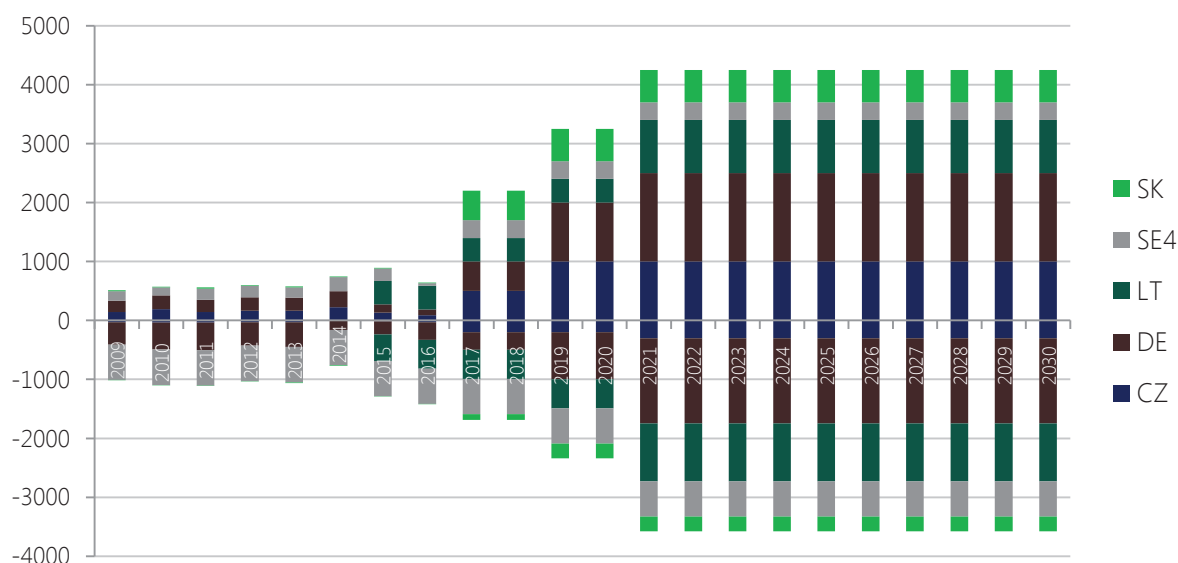
Growth of RES generating capacity for 2016-2030 on basis of the 2050 Energy Policy of Poland





## Maximum cross-border exchange capacity [MW]

PKEE analysis



The forecast of maximum annual cross-border NTC with neighbouring countries was developed in-house based on system data published by PSE, ENTSO-EE and the assumptions of the European Union's 2050 climate policy strategy. The result is available import and export capacity every year in specific directions expressed in MW. Positive values mean import capacity, negative mean export capacity.

One of the key parameters was to define the level of operation and maintenance (O&M) expenses for each generating unit, expressed in thousands of PLN/MW. This assumption is among the most crucial for the model, as together with the level of new investments CAPEX it is the most important factor influencing the answer to the question whether obtaining capacity is less expensive from new or from existing units and demand reduction.

In its determination we followed these assumptions:

- we have diversified the O&M expenses per basic fuel and class of units according to their installed capacity,
- we have made the 2050 horizon forecast a function of assumed dynamics of real remuneration,
- we have defined the O&M expenses as fixed costs without depreciation plus overhaul expenses.

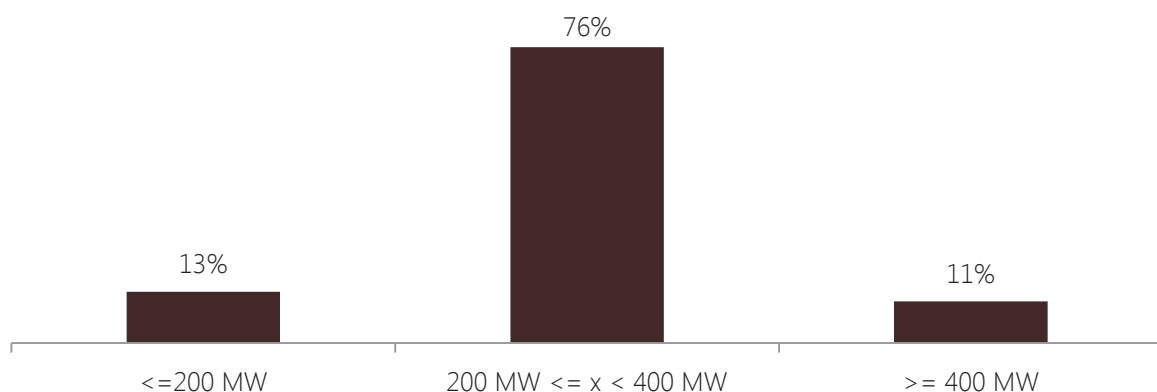
To differentiate by fuel and unit capacity we used the breakdown into:

- Hard coal-fired power plants,
- Lignite-fired power plants,
- Gas-fired heat and power plants,
- Biomass-fired power and heat& power plants.

Based on publicly available data we have determined the level of fixed costs in each fuel category in 2014, we have adjusted the fixed costs for depreciation and added the overhaul expenses. The graphs below present capacity structure in two most numerous power plant categories.

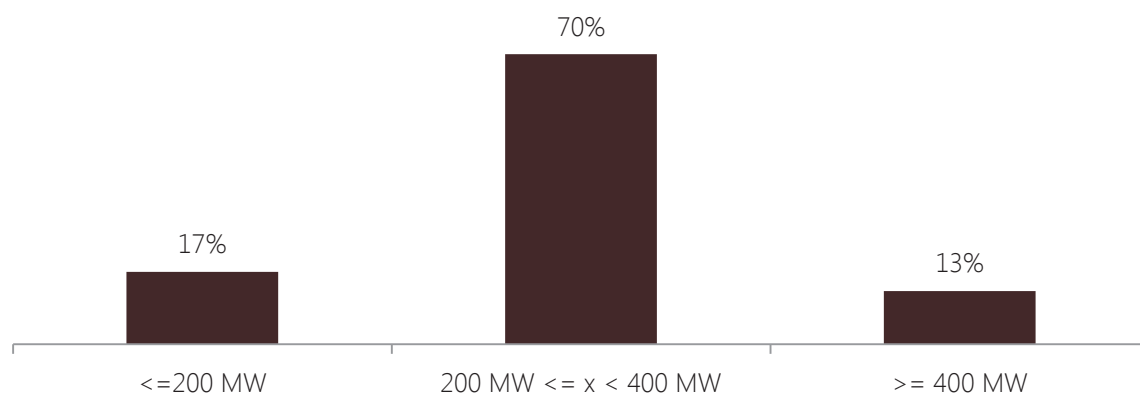
## Installed capacity structure by hard coal-fired unit class

PKEE analysis



## Installed capacity structure by lignite-fired unit class

PKEE analysis



### 3.2. Market development scenarios

To assess the consequences of using various mechanisms on the electricity market three scenarios were analysed:

1. **EOM:** scenario consisting of evolution of present regulations of the electricity only market. This scenario eliminates all capacity reserve remuneration elements, also in form of strategic capacity reserves (Interventional Cold Reserve). The TSO is not purchasing any capacity reserve services on behalf of energy consumers. Free market exit is possible for its participants – i.e. disconnection of generating units is possible even if it would result in increased frequency of application of energy supply curtailment degrees. Generating units keep being retired from the market for as long as they do not meet the condition of individual rationality to keep them in the market – understood as generating at least zero cash flows. The constraint of assurance of generating adequacy in the National Electricity System may be violated in this scenario as there is no market mechanism for pricing the capacity reserves, thus the level of capacity reserves is a result, not a constraint of the model.

2. **EOM plus:** evolution of present electricity market regulations begins to selectively include the capacity reserve pricing methods, but only as current operating reserves and the strategic reserve. These solutions are allocated to individual generating units that are not meeting the condition of individual rationality (they are losing money by staying only on the electricity market), but on the other hand are needed to assure demand coverage in the National Electricity System. The constraint of assurance of generating adequacy in this scenario may not be violated, whereas in this model for purpose of calculations this criterion is defined as LOLE=3 hours.

3. **CRM:** scenario assuming elimination of existing solutions pricing operating and strategic reserves and evolution of market mechanisms towards separate pricing of electricity and capacity. It is the only scenario allowing advance contracting of capacity in bilateral contracts with the TSO and thus is characterised by lower cost of financing. All generating units which would have not been disconnected in an optimum situation are characterised by at least zero discounted cash flows. The scenario is driven by criterion of optimisation of social welfare with the constraint of assuring generating adequacy in the National Electricity System at LOLE = 3 hours.

It can thus be said that from the modelling perspective these scenarios reflect the opinion that the electricity market is a private good market (EOM) or public good market (EOM plus, CRM) by, respectively:

1. (EOM) – introduction of the constraint of achieving at least zero discounted cash flows without any additional revenues from sale of capacity or capacity reserve services, but ignoring the limit of meeting the capacity balance without participation of administrative measures (power supply curtailing degrees).

2. (EOM plus and CRM) – introduction of limitation of meeting the capacity balance without participation of administrative measures but ignoring the condition of individual rationality (missing money). Such an assumption interprets the electricity market as a transferrable utility mechanism that utilises both electricity pricing and capacity pricing mechanisms as means to achieve the optimal distribution of costs and benefits between market participants. In a particular case when use of capacity reserve would be unnecessary in the optimal solution, only the electricity pricing mechanism would be used. In the studied cases in each calculation year achieving optimum social welfare requires the use of capacity pricing possibility.

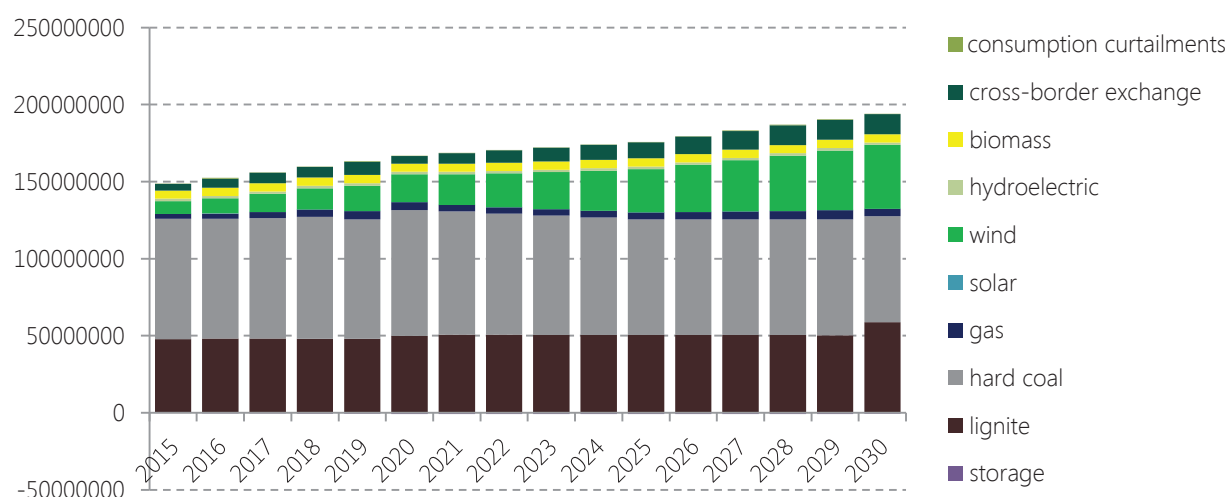
The following sections of this paper present the quantitative results for the market development scenarios defined above.

### 3.3. Analytical results

The first of the results of the model is a breakdown of electricity production by fuel mix. It is worth noting that every scenario assumes identical growth of subsidised renewable electricity sources, which is not a result but one of the constraints (parameters) introduced to the model. Without subsidies to renewable energy this model would not adopt the RES capacity to reinvestments and there would be a regression in generation from these sources – progressing along technical wear and tear of existing equipment or its opportunistic relocation by investors to countries offering subsidies (rent seeking).

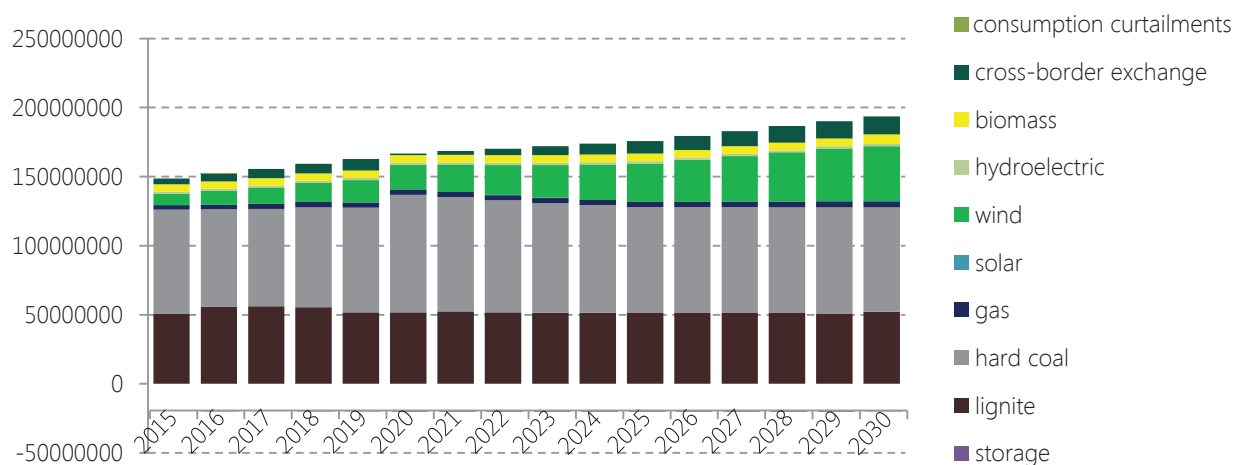
## Generation mix in EOM scenario [MWh]

PKEE analysis



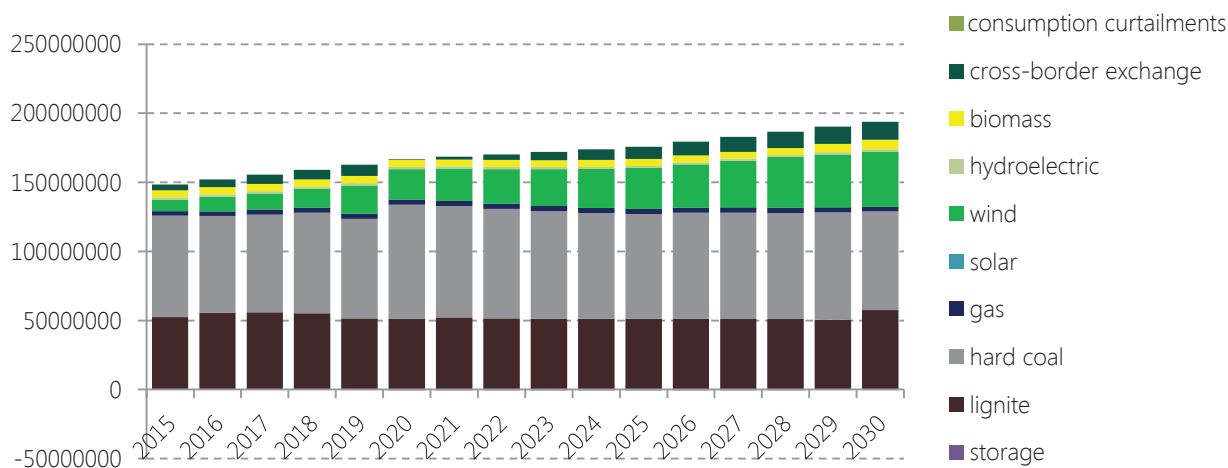
## Generation mix in EOM plus scenario [MWh]

PKEE analysis



## Generation mix in CRM scenario [MWh]

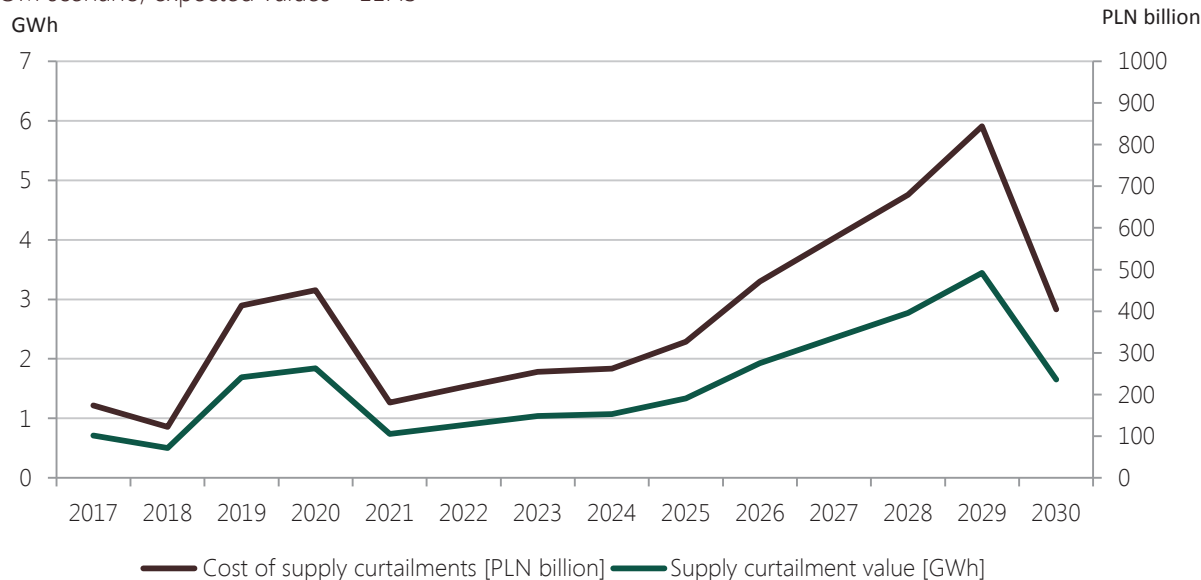
PKEE analysis



Introduction of capacity payments, both in the CRM and in EOM plus scenarios does not significantly influence the generation mix. Although the decarbonisation policy in each of the market development options influences the electricity imports to Poland, a significant difference is noticeable only in case of the EOM scenario, characterised by both higher electricity imports and relatively frequent energy supply curtailments.

## Administrative electricity supply curtailments (right axis) [in PLN billion] and the lost opportunity costs (left axis) [GWh]

EOM scenario, expected values – EENS



It is worth noting that the model assumes that the current consumption curtailment scheme used by the TSO will significantly improve, i.e. curtailments will be introduced selectively in selected hours and exactly to the extent they are absolutely necessary. In practice for many reasons this assumption is optimistic for the EOM scenario:

- In critical balancing situation the TSO is rather willing to create a safety margin, as they do not know with full certainty what will be the capacity balance in a given hour. This means that the curtailment degrees may in this scenario include bigger volumes than indicated by the model, translating to higher costs too.
- The current curtailment degrees solution is not very precise and despite capacity shortages during single hours of the day, it is more probable that the curtailments will be extended to longer periods of dozen or so hours. The model assumes that development of EOM will also result in possibility of eliminating this deficit.
- Electricity consumers at present are limited in their ability to react swiftly and precisely to requests from the TSO, and the nature of their businesses may result in single-hours curtailments causing resignation from capacity demand for longer periods of time. The model optimistically assumes that the consumers will be able to elaborate on their own and at their expense, negligible in system scale, solutions allowing fast reduction and reactivation of business activities.

In this sense the model provides the lower assessment of actual costs of energy not served that will be borne by customers, placing the EOM scenario in a better light.

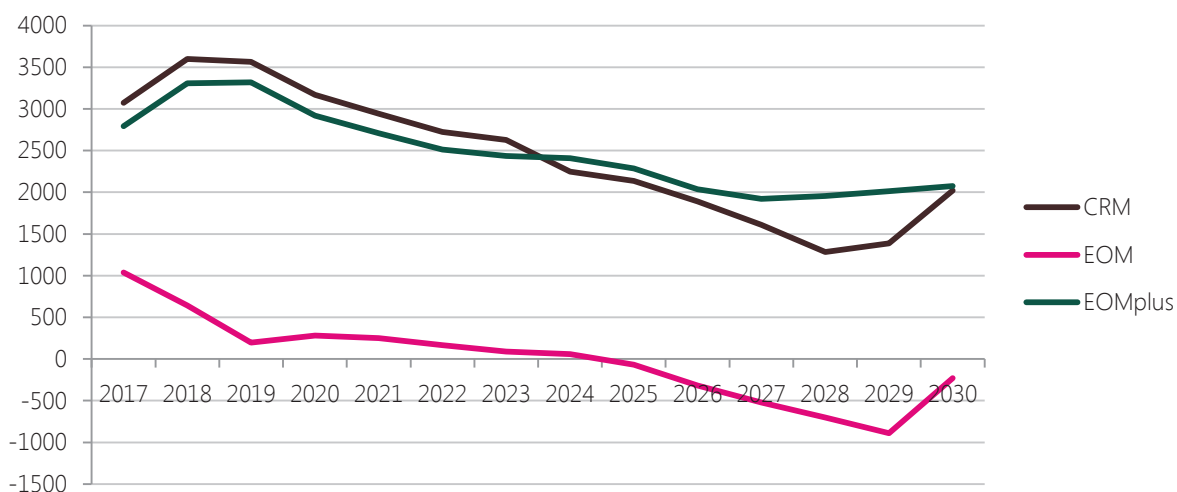
Another important result of the analytical effort is the level of domestic generating capacity reserve and market-based reduction of demand in the National Electricity System, also pointing to the years subsequent investments are being implemented in the National Electricity System.

The model is capable of demonstrating both the expected capacity reserve values – being a certain analogy to the deterministic values of supply and demand balances presented by the PSE (TSO) as well as extreme scenarios (summer, winter and transitional seasons). Extreme scenarios may be compared to current deterministic supply and demand balances by the TSO accompanied by a “reserve required” request.

The main difference between these scenarios results from weather variations. Expected values of wind generation, demand, photovoltaics generation and dropouts in dispatchable capacity of conventional units provide the first general picture of the trends in supply and demand balance in the National Electricity System. In practice all these values may be treated as stochastic processes that due to their variability may temporarily lead to tighter situations in the system. For this purpose the sets of these variables have been validated by historical back-casting. Arbitrarily, as the limit level of sample (the most extreme scenario) LOLE = 3 hours level was adopted. This means that administrative consumption curtailments to this threshold level will not be disclosed by the model.

As opposed to the TSO balances, the PKEE model allows balancing the National Electricity System using cross-border connections. Such approach has advantages and drawbacks alike. On one hand it is a way to assure the capacity reserves requiring investments in cross-border connections financed from outside the market – so it is not encountering the profitability problems that burden the generating units (the total costs are being socialised). On the other, despite the use of varying availability of cross-border connections in the model, it is a means beyond control of energy policy of a single state and as such may be subject to sudden and unpredictable changes.

**Expected value of domestic generating capacity reserves and market reduction of demand in the National Electricity System [MW], in a season with lowest capacity reserves, on working days, in the hour of lowest capacity reserve in a day**  
PKEE analysis



The above chart of expected capacity reserve volumes was developed as the average of scenarios and reflects the average only for a season with lowest capacity reserves and is limited only to working days. Comparing it to the volumes we are observing now, similar interpretation would come from averaging capacity reserves from morning or evening peak hour of the summer period for around 62 days, thus a total of 62 numbers. Although it is a simplified metric, it allows drawing several interesting conclusions.

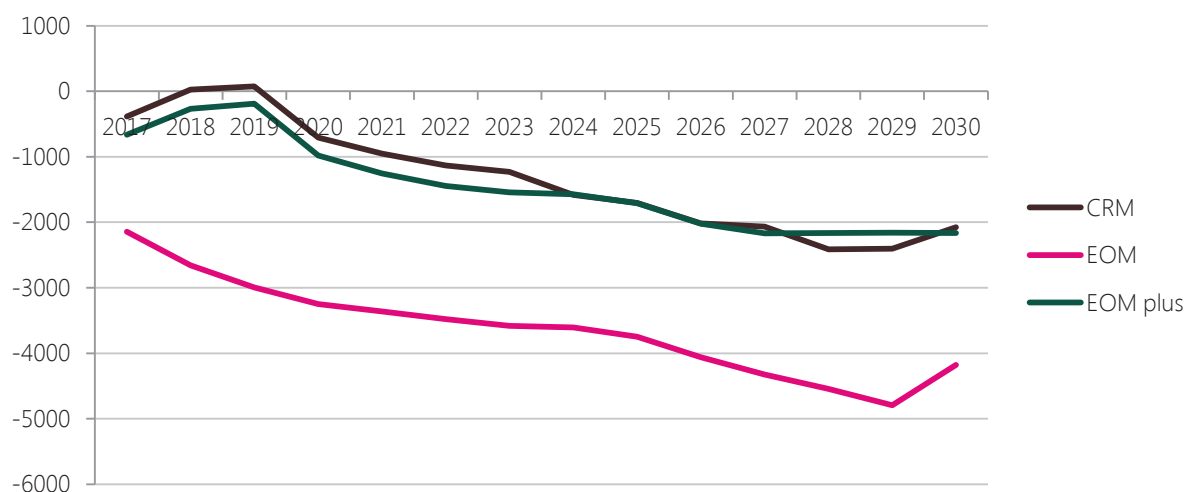
The present problem of missing money should, in order for the generating units to achieve positive financial results, lead to retirement of ca. 2GW in 2017 and ca. 1.5GW in subsequent years in the EOM scenario. Only such level would allow the electricity generating sector in Poland to regain profitability (with lack of mechanisms assuring profitability of maintaining operating or strategic capacity reserves, or in absence of capacity market). A significant assumption of this model is that although there are limitations as to the pace of new capacity build (lead time) the exit from the market may be instantaneous. Though the current regulations actually provide for a three-year notification period in case of intent to retire generating units from operation (a market exit barrier) but the EOM scenario assumes they will effectively be waived to free the market.

Change in the discount rate influences the time shift, but in principle the EOM plus and CRM scenarios may be characterised by very similar levels of domestic capacity reserves.

The energy only market (EOM) along with growth of subsidised renewable sources decreases individually rational (to investors) generating capacity reserve in the National Electricity System. As of 2025, on the energy only market, even the expected value of capacity reserve becomes negative. So there are grounds for a thesis that variability of generation volume and electricity wholesale prices for conventional units that is increasing along with growth of RES results in drop of capacity reserves in the energy only market (EOM).

### Minimum value of domestic capacity reserves and market demand reduction in the National Electricity System [MW], during a lowest capacity reserve season.

PKEE analysis



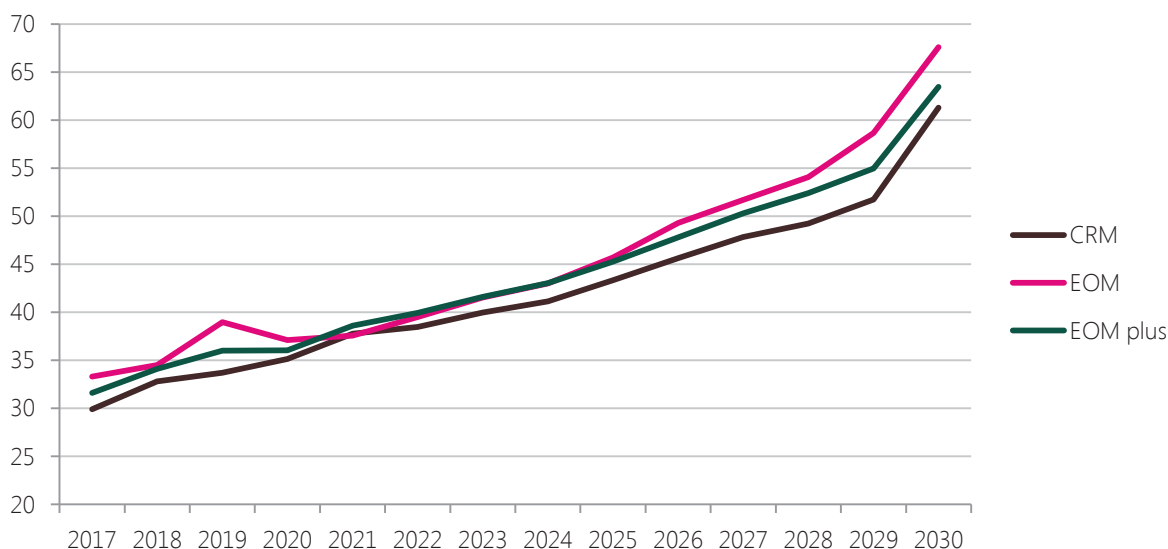
The above chart illustrates the domestic capacity reserves in case of extreme weather phenomena. Interpretation of this metric merits explanation:

1. Only the value of domestic reserves is presented (both the DSR and the generating sources), in particular an additional reserve may be obtained by using the cross-border connections and the negative value on the above chart does not mean lack of capacity for domestic customers.
2. It is a reserve that assumes extreme weather conditions that may but do not have to occur in a given year. Simply put – one should expect realisation of the minimum level shown in the above graph once per around 5 years.

All the variants of development of market mechanisms utilise the cross-border exchange as a source of capacity reserve. In case of CRM and EOM plus, relying on this capacity source to a limited extent does not cause negative consequences such as a threat to electricity supply security of end-users – however, the model does not use in the optimum solution the cross-border capacities to a full extent, considering uncertainty of supply from this source. The cause for concern, however, is the EOM scenario that in time and with growth of RES collapses in presence of significant capacity shortages. Analytical view supplements the picture with expenses borne by electricity users and producers.

### The sum of costs of electricity production (including financing of liabilities of producers), costs resulting from electricity supply curtailments and costs of electricity imports [PLN billion]

PKEE analysis



The above expenses in particular include the CAPEX and OPEX of growth of renewable energy sources and cost of electricity imports. In case of import it may be said that its level is very similar in CRM and EOM plus scenarios (thus it does not influence their interrelation); slightly higher import level in the EOM scenario results in further reduction of its attractiveness. All scenarios assume the same growth of RES, resulting from the assumptions for this part of the fuel mix being adopted in line with the 2050 Energy Policy of Poland (PEP2050). Although this paper does not refer to the ways of financing that growth it is worth noting that it requires including additional fees in customers' bills in addition to the electricity wholesale prices.

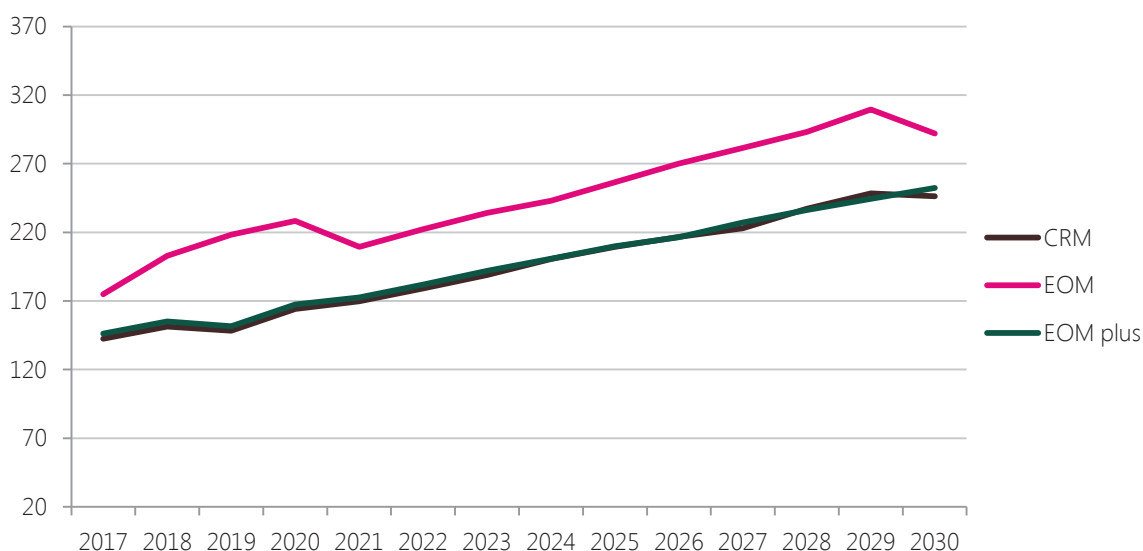
On average the least expensive scenario is the CRM, with the other two being more expensive: EOM plus (by 4.6% or PLN 1.93 billion per annum respectively) and EOM (on average by 7.56% or PLN 3.18 billion per annum).

When analysing the results from consumer perspective the important results are both per unit wholesale electricity prices and the sum of expenses they will bear.



## Marginal costs of electricity supply in the National Electricity System [PLN/MWh]

PKEE analysis

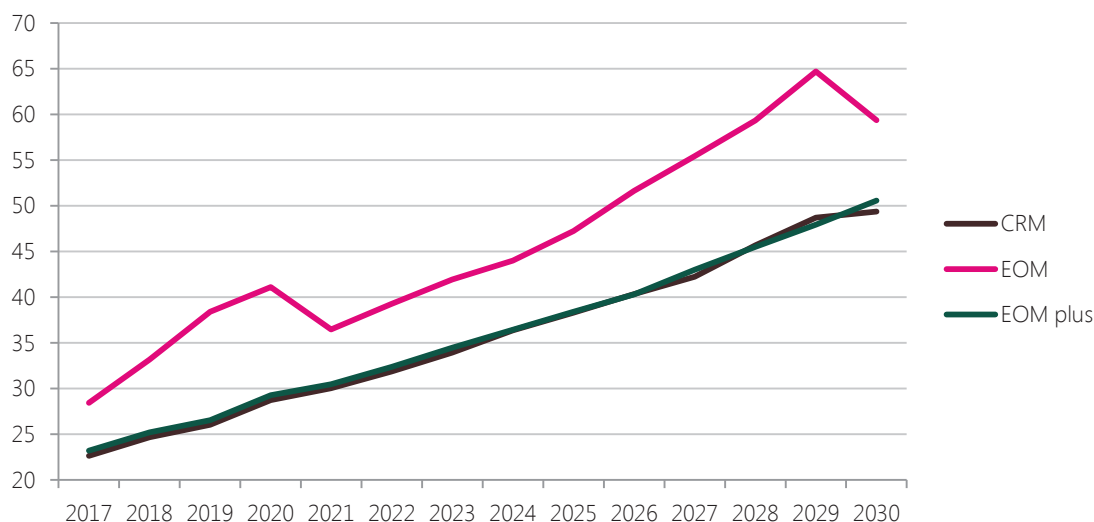


It should not come as a surprise that the highest marginal costs of electricity supply that may be interpreted for the needs of this analysis as wholesale electricity prices, are provided by the EOM scenario. This scenario, where total costs of producers must be transferred via a mechanism boiling down to a single-price multi-commodity electricity auction (fixing), being also an important factor shaping the price expectations for futures contracts. Exact wholesale prices in the EOM plus scenario will depend on the extent to which correction mechanisms will introduce an alternative cost to electricity sales.

The model assumes neutrality of such correction mechanisms with respect to electricity wholesale prices, resulting in very similar EOM plus and CRM costs to consumers. It should be noted, however, that the designing such correction mechanisms may be very difficult or impossible, so it is a very optimistic assumption for the EOM plus scenario. Similarly, the prognosis horizon is favourable to the EOM and EOM plus scenarios as it falls before the period of important investments in the National Electricity System. Thus it avoids the growth of costs of financing these investments, very negative to the EOM and EOM plus. In summary, the adopted assumptions are very conservative with respect to evaluation of benefits of implementation of the CRM.

**The sum of cost borne by consumers: electricity purchases from domestic sources and import; costs resulting from electricity supply curtailments; capacity purchase costs, but without subsidies required for growth of RES [PLN billion]**

PKEE analysis



The above chart to a large extent illustrates the differences in electricity wholesale prices constituting the biggest cost item incurred by consumers regardless of scenario. Thus, similarly to the previous chart, in the EOM plus scenario it contains a far reaching assumption of lack of interactions between the way of capacity financing and electricity wholesale prices. In practice it should be expected that **achieving such state will be very difficult or outright impossible and** – just like the electricity wholesale prices – also **the costs to consumers will be higher in the EOM plus scenario**. It is worth noting that, particularly in confrontation with the chart presenting the costs incurred by electricity producers, the above chart does not include any additional costs of subsidising the growth of renewable energy sources. Determining the costs of realisation of this element of the energy policy was not an objective of this report.

As opposed to previous charts, where it was possible to relatively accurately assess individual items, in case of decomposing the social welfare onto producers and consumers an undefined cost item of capacity purchasing appears. It results from the fact that the alternative costs of shortage of supply to consumers are very high, while the producers require a relatively minor adjustment of the current utility transfer function to achieve individual rationality for retaining a power station in the National Electricity System. Taking into account the difference in costs incurred by the consumers in these scenarios, financing maintaining of the generating capacities and reduction of demand allows savings of on average PLN 10.1 billion a year with respect to scenario not employing such tools (EOM). Such figure may be interpreted as upper assessment of the cost of capacity mechanisms that should be acceptable to its users. In case of the above chart a maximin fairness approach was used, i.e. adjusting the remuneration of producers only to the extent to which their generating units are unprofitable (not including depreciation, i.e. the value of present assets has a value of zero unless it generates cash flows in the future), with discriminatory payments. An alternative could be a correction of individual rationality with respect to individual generating units, i.e. assuring that every single generating unit is profitable (or deciding to retire it), with payments identical for all unit. Selection of appropriate approach may be made considering for example the aspects of competitiveness of the capacity market, adequate motivation for investments in maintaining and developing the most economic generating units by their owners – however this was not the objective of quantitative analytical work in this report.



The European Union's climate and environment policy significantly influences the operation of electricity markets and their form.



Energy Only Market does not provide return on investment, resulting in reduced or abandoned investment decisions.

Forsaking the implementation of capacity market will cost in excess of PLN 10 billion a year.

From consumer perspective it will have grave consequences of dramatic decrease of energy supply security.



## About us

The Polish Electricity Association (PKEE) represents the largest electricity producers and leading industry organisations in Poland. We focus mainly on improvement of our industry's functioning in a modern market economy.

Our engagement in many national, EU-wide regulatory projects and activities helps the Polish electricity sector to face the challenges concerning the transformation of the energy market in the field of:

- ▶ ensuring security of electricity supply,
- ▶ achieving a competitive market with affordable electricity prices,
- ▶ environmental protection and climate policy, and
- ▶ development of modern technologies.

We support development of the Polish electricity industry by opinion-forming activities to improve investment predictability and shape a rational, industry-friendly regulatory environment – both at the national and EU level.

We are a member of the Union of the Electricity Industry – EURELECTRIC, pan-European association of utilities. Our activity in the field of EU regulations is further strengthened through our office in Brussels.

At national level, we represent an important voice of the sector regarding energy issues, and we cooperate with the Polish government through consultation of legal acts and initiatives concerning our industry's operations.

We are looking forward to working with you.



[www.pkee.pl](http://www.pkee.pl)



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