A qualitative assessment of the effect of the introduction of the capacity market on the CO_2 intensity of the Polish Power System

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Summary

The purpose of this study is to assess the effect of the use of the envisaged capacity market on the CO_2 emissions related to the electricity generation processes.

The introduction of the capacity market proposed by the Government should be analysed as an integral element of the system of regulations governing the Polish Power System (PPS) and its effect on the latter system should be analysed in a comprehensive manner, along with other regulations. If the regulations on the capacity market addressed investments in energy power stations which can participate in the baseload demand of the energy market, this would have a long-term effect on the electricity generation mix. The context of the national energy policy is particularly important as this policy determines the level of energy demand and the level and profile of capacity demand and makes it possible to define a set of possible, diverse measures in the economy as a whole (both on the supply and demand sides) and its international environment which can be used as an alternative in order to satisfy these needs in a rational way.

For the reasons listed above, this study consists of the part devoted to a qualitative definition of hypothetical scenarios and options of the development of the Polish Power System and an assessment of the need for investments driven by the capacity market, as well as the part devoted to an assessment of the CO_2 emission intensity of the electricity generation sector under the scenarios and options.

In each scenario and option, the capacity market drives investments on an auxiliary basis and modifies the extent of the use of energy power stations in the PPS. Given the differentiation of the levels and profiles of capacity demand and the marginal costs of energy, in each scenario and option, along with regulations, it leads to different structures of assets, levels of their utilisation and, ultimately, CO_2 emissions.

The estimates which have been made should be regarded as qualitative: solely as ones representing of the expected directions of change in CO_2 emissions and the absolute levels of these emissions related to the national electricity generation, depending on the adopted scenarios of the development of the national economy and options of the structure of sources used to satisfy its demand for energy and electrical capacity (including imports).

The level of CO_2 emissions as a result of the introduction of the proposed capacity market will depend, in particular, on its effect on the structure of the generation assets operating over long periods, i.e. to satisfy the basic needs of the economy. The structure of energy power stations in operation to balance the variable capacity needs will have a lesser effect in light of the short operating times of these stations. **A particularly adverse effect (from the point of view of CO_2 emissions) is the use of the capacity market to build new coal-fired stations intended to operate in the baseload part of the system, while using, at the same time, old (modernised) stations to balance the needs of variables (sub peaks or compensating for power loss from other sources).**

Decentralisation of the power system, involving the use of ICT and automation and a relevant legal regulation, makes it possible with large probability to gain substantial benefits in the process of balancing the capacity of the system by triggering prosumer activities, i.e. using the many opportunities for generation and demand (volume and profile) management,

as well as synergies with other economic processes, such as electromobility, heating or waste disposal. **The total CO_2 emissions in 2021–2035 in the most favourable option (a decentralised one with a large share of renewable energy resources) will be lower by 29% that those in the option with the highest emissions (a centralised one with a large share of coal). This means that the mean annual emissions would be lower by 16.9 million tonnes of CO_2, representing more than 10% of the 2015 emissions from this sector.**

Imports are an attractive means of balancing the variable demand for electrical capacity. In terms of prices, imports are highly competitive with respect to large-scale domestic energy power stations on the electricity market and cause their marginalisation. In contrast, imports are significantly less competitive against domestic disperse energy generation .

Abbreviations

CAPEX	– capital expenditures
CHP	– combined heat and power
CM	– capacity market
CO_2	– carbon dioxide
DSR	– demand side response
EU	– European Union
GDP	– Gross Domestic Product
GJ	– gigajoule
GW	– gigawatt
ICT	–information and communication technologies
kV	– kilovolt
MW, GW	– megawatt, gigawatt
MWh	– megawatt hour
OPEX	– operating expenditures
PPS	– Polish Power System
RES	– renewable energy sources
SC1, SC2	– scenario 1, scenario 2
TSO	– Transmission System Operator
TWh	– Terawatt hour

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Justification for the introduction of the capacity market

In the justification [2] for the Draft Act on the Capacity Market [1], its proponent thus explains the need for its introduction:

It is an obligation of the State to ensure energy security understood to mean the state of the economy enabling the satisfaction of users' current and prospective demand for fuels and energy in a technically and economically viable manner, while meeting the requirements of environmental protection.

The security of electricity supply depends, first of all, on the availability of energy power stations . Over the next 20 years Poland can experience a substantial problem of missing capacity as a result, on the one hand, of the predicted increase in the peak demand for capacity and electricity and, on the other hand, of the significant extent of the planned decommissioning of power stations.

A missing capacity can make it necessary to impose constraints on the supplies of electricity and its consumption by users.

The challenges identified by the proponent which the State faces seem to be real ones. They result from economic growth and the foreseen gradual shift to electricity from other energy carriers (e.g. liquid fuels as a result of the development of electromobility). This will cause an increase in the demand for electricity and the development of renewable energy sources (RES) with very low generation costs. Moreover, the fluctuating availability of RES will contribute to increased electricity demand. At the same time, at present the PPS is not well prepared for these development-related challenges.

A model of the effects on the energy and capacity dual-commodity market

Investments in conventional , large-scale energy power stations[1], which are characterised by long lifetimes in technical terms, require very high, concentrated capital outlays. The dynamic changes unfolding around these investment processes, both of a technological and regulatory nature, make it more likely that energy prices will fall, the generation costs will diminish and, in consequence, the competiveness of these generation assets in the market will decrease and their lifetimes in economic terms will become shorter. This increases the risk attributed to the capital invested and prevents the launch of such investment projects under commercial conditions. Given the fact the stakeholders of the conventional, large-scale electricity sector increase their pressure seeking public support for offsetting the capital expenditures (CAPEX) or operating expenditures (OPEX) incurred. This would entail, among others, cheap credits, guaranteed revenues or electricity prices.

Taking into account the inadequacy of the investment incentives to ensure the commercial development of conventional energy power stations in the PPS which would be

[1] Conventional, large-scale electricity generators mean here power plants with capacity exceeding 200 MW which use thermal circuits to generate electricity.

related to a single-commodity energy market, the proponent proposed the introduction of a capacity remuneration mechanism in the form of a centralized capacity market which would guarantee revenues for the readiness to balance the needs of the PPS. In general, this support is available to the capital invested in the construction of electricity generators or the ability to permanently reduce demand or to modify the time characteristics of demand. As a mechanism of an administrative character, it is available to high-outlay investment projects and entails the risk of unviable allocation of substantial public resources. This can slow down or even halt for a long time the correct development of the electricity generation sector, which is a field of such importance for society and its economy. Therefore, the capacity market requires multi-aspect analyses, public discussions and transparency.

The mechanism proposed in the Draft Act is intended to induce measures which will have the following effects:

1. they will make it possible to balance the capacity in the periods of extremely high demand for capacity (peak or sub peak) or in the periods when for technical, weather-related or other reasons part of the capacity in the PPS is unavailable for a short time;
2. they will ensure the profitability of investments enhancing the generation capacity intended for long-term baseload operation to meet the demand for energy.

Given such a duality of objectives, the criteria for selecting the means of their achievement are not self-evident.

Indeed, for units intended for short-lasting operation (peak, sub peak and reserve units) the particularly important factors include low CAPEX, high operating flexibility and as flat efficiency curves as possible in the whole load range. OPEX is less important, mainly exactly because of the short-lasting operating time, but also high electricity prices in these conditions. Such generators pose a problem of gaining an appropriate return on the capital spent, since when they only remain in a long-term standby status they bring no revenues in a energy-only market. Economic viability can be achieved only due to very low outlays, very high prices in the operating periods and the frequently dispatched operations to respond to frequent capacity-balancing problems. In general, the economy resists both extremely high prices and the frequent occurrence of the extreme needs. Therefore, the only certain way in which investors can ensure that such new stations are economically viable is to reduce CAPEX.

Due to the economising on investment outlays, the functions of providers of peak capacity and, in particular, sub peak capacity are often performed by relatively old and relatively low-efficiency facilities which have lost their ability to compete in the baseload market and are pushed out of this market in a natural way. Their distinct advantage is the absence of outlays or outlays on a limited scale which are related to modernisation. Unfortunately, in the scope of capacity supply services, their functionality is often constrained by their technological features which hamper or prevent their operation in a large range of quickly varying loads and by their frequent shutdowns and start-ups. Such operation causes a substantial deterioration of efficiency and faster wear; therefore, the preferred segment of their operations includes sub peak periods, which makes it possible to slightly extend the periods of their uninterrupted operation. In terms of CO_2 emissions, this is not beneficial, since stations with relatively low efficiency operate for a relatively long period of time.

The capacity balance can also be complemented with imports; certainly, if appropriate generation and transmission capacity is available. An alternative solution, particularly in the periods when district heating services are rendered, can also be the use of combined heat and power plants (CHP) (cooperating with the PPS and local district heating systems). To some extent, such plants can differentiate their operating capacity between electricity and heat, using the accumulation properties of district heating systems.

Irrespective of which stations are set in operation (in addition to baseload plants) in the peak and sub peak periods, **as regards CO_2 emissions the most important issue is which generators will operate for a long time as baseload plants**. In turn, this will be a result of the manner in which the second objective of the proposed capacity market will be implemented.

For units which are intended to operate as baseload ones (as a rule, for a long period) the most important issues include: competitive OPEX achieved for their operation under conditions close to nominal ones, guaranteeing a stable share in the market, as well as a low breakdown rate and low harmfulness for the environment. As pointed out earlier, the currently functioning single-commodity market does not encourage investments in conventional , large-scale energy power stations which balance, at the same time, the capacity in the baseload layer of demand (in other words, the operation of baseload capacity is needed to balance the capacity also when short-lasting needs occur by using additional sub peak and peak load generators). **Since the electricity generation sector is practically going through a technological revolution and a change of the model of operation of the PPS is underway, there is a particularly high risk that decisions taken administratively on State aid will be faulty ones.**

In particular, the following factors combine to produce this very high risk:

1. The scale of outlays and the long-term consequences of decisions on large-scale investments (gas-fired power plants: 20–40 years, coal-fired power plants: 30–50 years, nuclear power plants: 60–80 years, hydro-power plants: 100–200 years), which once taken can block the opportunities for alternative development, to the detriment of the economic position of the country as a whole.
2. The dynamic development of micro-scale, small-scale and dispersed technologies – localised close to users, combined with dispersed accumulation capacity, with fast falling prices.
3. The dynamic changes in the fossil fuel markets causing price changes. E.g. it can be expected that, as a result of the development of electromobility in the world, oversupply of hydrocarbons will occur and their prices will fall. In consequence, coal prices will fall, improving the profitability of electricity generation from these carriers, but this will also cause a collapse of domestic deep hard-coal mining.
4. The uncertainties related to the estimation of electricity demand, with consideration given to factors which have opposite effects, such as electrical transport or heating, and, on the other hand, the efficiency of technical solutions and an environment-friendly change in users' behaviour.

If only these uncertainties are taken into account, it cannot be said unequivocally which technologies will met the baseload demand of the PPS. This will strongly depend on the decision-making criteria. These, in turn, will depend to large extent on short-term interests, including only partly the economic ones. These criteria will be related to the implementation of one or another long-term national policy in quantitative terms only. E.g. the policy can be characterised by:

1. The continuation of the existing, traditional model where:
   a. Coal will remain the dominant fuel and in time it will be gradually complemented with nuclear energy.
   b. The structure of power stations will change mainly by the replacement of lower-efficiency units by higher-efficiency ones (e.g. at present their net efficiency is about 45–46%). It can also be expected that the share of cogeneration will grow and that a limited number of gas-fired stations (with the net efficiency of 57–59%) will emerge – provided that gas prices fall.
   c. The relatively small national system will be sensitive to excessive capacity concentration; therefore, a share of modernised units of the 200–500 MW class will be maintained while allowing for slightly lesser generation efficiency (compared to units of the 1,000 MW class).
   d. The system will be sensitive to a large share of wind and solar (photovoltaic) sources with fluctuating generation capacity; therefore, their share will be limited by administrative means.
   e. In such a case, energy will be relatively expensive, which will reduce both the level of its consumption and, in consequence, the GDP growth rate. It can also cause a higher share of energy costs in household budgets.
2. A quick integration of the European Union, according to a traditional model, where:
   a. The fuel mix used for generation purposes will result from the competitiveness on the large European market, meaning that, in general, the role of coal will be quickly reduced. Domestic large-scale energy power stations using fossil fuels will have, as a target, capacity-balancing functionalities of (reserve, peaking and sub peaking capacity) on the large European market. Their technical solutions should be adapted to such functions. For this reason, the development of gas- and oil-fired capacity can be expected.
   b. The share of electricity imports will significantly grow.
   c. Domestic sources with a local character will remain attractive: municipal and industrial, able to split their costs among different services (the supply of heat process, a heating service, waste disposal, transport etc.) and also limiting the supply implementation costs (given the proximity of suppliers and end users).
   d. The electricity price will be low and the demand for electricity will be high.
3. The technological transition according to the new PPS model, in the course of which:
   a. The share of electricity needs balanced by sources connected to networks with voltage levels at which most of the demand they satisfy is identified, including autogeneration, will quickly grow.
   b. The share of diverse, dispersed energy storage methods, technologically integrated with generators or associated energy uses, will substantially grow.
   c. The development of information and communication technologies (ICT) will enable the implementation of dynamic tariffs and the adaptation of energy use profiles to the current generation capacity. Active market players, able to resell surplus electricity, will apply higher-efficiency solutions in the scope of energy use, thus enhancing their sales.

d. The electricity price will be very low and the quality of development will be determined by the quality of energy (the voltage level, stable frequency, harmonics, the number and duration of interruptions etc.) related to the appropriately developed supply infrastructure.
e. Traditional sources will be gradually marginalised. They will have a stabilising and reserve-providing role.

In the long term, each of these policies will lead to different electricity demand levels and also different capacity demand levels and characteristics. This will induce different choices of generation technologies, the need for different support from the capacity market and, in consequence, CO_2 emissions. **In conclusion, the proposals related to the introduction of the capacity market cannot be assessed unequivocally, objectively without knowledge of the context of energy policy in the framework of which it is to be implemented**.

Estimation of CO_2 emissions from electricity generation to meet the needs of the PPS under different scenarios and options

Initial assumptions

The further part of the analysis focuses on the estimation of the CO_2 emission levels under alternative ways (scenarios and options) of achieving the objectives indicated in the Draft Act. No further analysis of the proposed capacity market solutions was presented; no economic analyses were launched, either. The emissions were estimated for a period of 15 years: from 2021 to 2035.

CO_2 emissions result from electricity generation by stations which operate using fuel combustion technologies; therefore, they do not depend on the level and structure of the capacity installed in the PPS, but on the level and structure of the capacity dispatched to operate and generate electricity. This can be done only on the basis of physically existing stations (including foreign ones) which can be accessed appropriately. In this scope, investment decisions driven by the capacity market influence the composition of the set of facilities from which the operating ones can be selected. The criteria for selecting generators for operation depend on the complete set of regulations (administrative, economic and environmental ones).

CO_2 emissions result from energy generation and one of its causes is the energy demand on the part of the national economy. Its distribution in time is also of importance. In general, the lower demand, the lower the emissions. The demand level depends on many factors and the important ones are as follows: the GDP level, demography, the structure of the national economy, the penetration of modern technology into the economy and the behaviour of energy users. In the medium term and, in particular, in the long term, they depend on the direction given to the basic development drivers, such as capital and the labour of an appropriate quality level, correlated to the capital The key here is education supported by relevant information, which determines not only the quality of work, but also the behaviour of energy users. All this takes place in the environment of regulatory models the manifestations of which are, in particular, prices (the market-based model) or orders and prohibitions (the administrative model). These observations are only apparently trivial, since decisions which are optimum in the long term most often hurt current interests and are difficult to accept in political terms. In turn, as a result of this, resources can be misallocated and hamper development (as said earlier).

The distribution of demand in time (i.e. the current level of needs) is important, since the more uniform it is (in graphic terms, coming close to the shape of a rectangle), the more often higher-efficiency facilities can be used, i.e. those with a lower emission intensity. This factor is disturbed by the limited availability of energy power stations, affected e.g. by planned shutdowns, breakdowns and the absence of appropriate weather conditions (the wind, sunlight, water etc.). The stronger the stimulus disturbing the composition of facilities in operation is, the greater deviation occurs from their mix which would be the optimum one at a given moment.

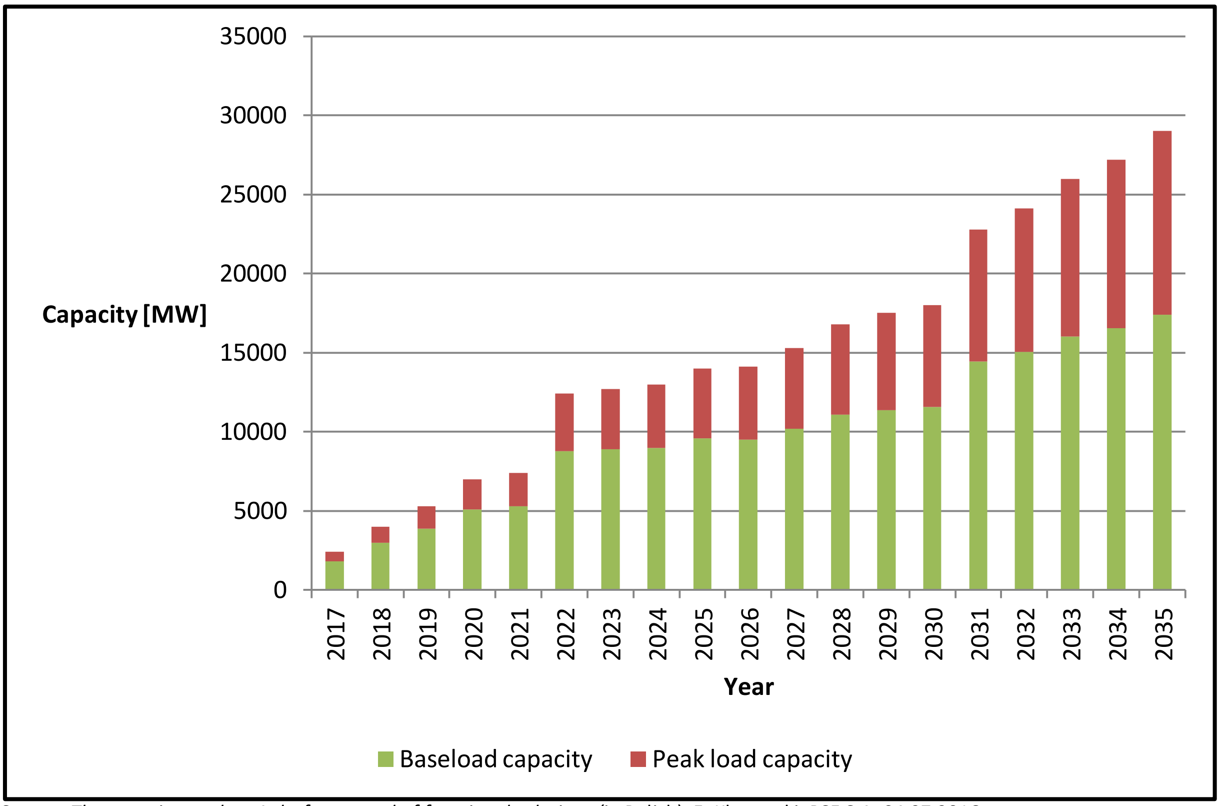
Until the moment when the share of generators whose operation causes CO_2 emissions becomes significant in the electricity balance, the demand for it will be of key importance for these emissions. If the share of zero-emission generators grew in this balance the importance of the electricity demand level for CO_2 emissions would diminish. There is no doubt that in the next dozen years or so generators causing significant CO_2 emission levels will dominate the mix of capacity providers available for electricity generation in Poland; therefore, the issue of the demand level is important.

A quantitative assessment of the situation predicted by 2035 in the PPS, presented by the Transmission System Operator (TSO) [4], was adopted as the starting point for the analysis.

Beginning with the definition of energy security and taking into account the development of different means of balancing capacity in the PPS, in the further study the concept of “the level of the need for the PPS to acquire the balancing capacity” was adopted to replace the simplified concept of “the required investments in the PPS energy power stations”. In the baseline scenario, in successive years, it will be equal in qualitative terms to the levels of the maximum annual shortages of the required capacity surplus as defined by the TSO. The capacity which will only be indispensable in the peak and sub peak demand periods was separated from the above levels. It was assumed that they would be used to balance the PPS needs for fewer than 2,000 hours in the year (on average, about 1,000 hours/year). It was also assumed that given the probably increasing share of fluctuating RES in the balances, the growing need to maintain the high quality of electricity and the situation on the market, the share of peak load and sub peak generators will grow from 25% to 40% in the period from 2017 to 2035 (Fig. 1).

With reference to this forecast of the demand for capacity to be provided by domestic stations, the baseline forecast of the gross electricity generation in Poland was estimated, against which changes in CO_2 emissions under the different assumptions on the ways of implementing this generation will be assessed.

Since the purpose of this paper is not to carry out an economic investigation, further considerations concern a certain probable scenario (SC1) on the electricity demand until 2035, which is related to the traditional model of electricity generation, with dominant stations supplying electricity to users in a centralised manner through the electrical grid with different voltage levels, requiring appropriate generation capacity levels and reserves. This scenario assumes the "natural" pace of modernisation of the national economy and also an improvement in efficiency within the PPS, corresponding to the technological progress currently available in conventional power stations. To a large extent, this scenario is an autarkic one.



Source. *The capacity market. A draft proposal of functional solutions (*in Polish), E. Kłosowski, PSE S.A. 04.07.2016

Fig. 1. The need to acquire the balancing capacity.

The second scenario (SC2) provides for the same levels of the GDP and demography as SC1, but it is characterised by the growing electricity generation capacity at dispersed generation , connected to the PPS at voltage levels corresponding in qualitative terms with the voltage levels at which the main demand for them is identified. Compared with SC1, it predicts the faster development of prosumer energy generation and CHP generation at local and industrial levels. Given the active users' participation in the electricity market in SC2, it also predicts the growing willingness to improve efficiency of electricity use and an active, dynamic response to the current situation in the capacity balances, based on accumulation and capacity management techniques. These assumptions have the following consequences:

1. The reduction of the generation needs on the market of large-scale generators:
   a) with the part covered by dispersed generation
   b) with the reduced needs to cover transmission losses

   The network losses identified in highest-voltage networks (400 and 220 kV) and high-voltage network (110 kV) represent about 1.6%, whereas they are about 3.1% in medium-voltage networks and about 5.7% in low-voltage networks (up to 1 kV) [5]. The energy transmitted from power stations to users incurs losses successively at all the voltage levels through which it must be transmitted and the losses related to transformation between voltage levels. The total energy losses in the PPS represent about 6.5%.

Capacity losses are not tantamount to energy losses, since, in accordance with the laws of physics, the arising network losses are calculated as the squared flowing current and the conductor resistance (I^2R). The value of the flowing current depends on the voltage, but also on the power transmitted. Therefore, a linear increase in the power transmitted causes an exponential increase in transmission losses in the course of its transport. Moreover, it causes the heating of conductors and a further increase in losses in response to the related changes in network resistance. For the purposes of further calculations, it is assumed that the average power loss level of 6.5% in the PPS can consist from 3% for low-demand periods, 12% of instantaneous energy (power) losses in the periods of very high network loads in the winter and up to 15% of instantaneous energy losses in the periods of very high network loads in the summer. The growing (massive) dispersion of electricity generation causes the limitation of its maximum transmission loads and, thus, modifies the profile of the network demand for energy to cover them, reducing the balancing needs on the market of large-scale power stations.

For the purposes of the analyses of the emission intensity, it is assumed that until 2035 the capacity of the dispersed generation connected to low-voltage and medium-voltage networks will grow to 7,000 MW (including altogether prosumers, local generators, small industrial plants and services). Due to the storage opportunities, from 2021 it will be possible to use up to 25% of this capacity in (peak load) capacity balancing services in the PPS. Irrespective of the generation activity, due to the reduction of long-distance transmission needs in the PPS the network transmission losses in the peak load periods will be gradually reduced from 15% to half this level, i.e. 7.5% of the total power resources.

2. A change in the capacity level and demand profile. An effect of the generation activity at the dispersed level will be a higher awareness of the value of electricity as a function of the situation in terms of capacity balancing. It is assumed that this will speed up users' investments in more energy efficient ways of meeting their own energy needs and a shift of the implementation times of certain operations which can be automated to those periods when power is cheap and available in the PPS (at least so as to release it for local sales in the high-price periods). It is also envisaged that locally available power storage facilities will be used, including batteries dedicated to transport.

   For the purposes of the analyses of the emission intensity , it is assumed that gradually, i.e. until 2035, about 10% of the maximum power demand will be shifted in time and met in lower-load periods of the PPS.

3. A change in the primary energy mix and the emission intensity. It is predicted that the growing smartness of electricity use will induce the application of different RES and waste-derived energy to generate electricity. In particular, it will be better correlated with the presence of the reasons for its use (e.g. solar energy for air-conditioning).

   For the purposes of the analyses of the emission factor, it is assumed that 50% (in a growing trend) of the capacity of dispersed generation connected to low-voltage and medium-voltage (as in point 2) will be zero-emission, 20% will be zero-emission in the balance (biomass), 20% (in a falling trend) will use hard coal in CHP technologies, while the other 10% will have a peak load reserve, using heating oil as fuel.

4. It is assumed that due to an active participation in energy markets and the willingness to enjoy benefits from trade in energy and capacity, the electricity efficiency will improve to 5% at the end of the period.
5. It is assumed that the degree of capacity use in peak load facilities is 1,000 hours/year and that in baseload facilities it is 4,000 hours/year.

In consequence, SC2 is characterised by both the final electricity demand level of 5% in 2035 (improved efficiency) and the demand for the coverage of transmission losses (particularly, in the lowest-voltage networks) reduced from about 6.5% to about 4.5% in the same year. It is assumed that the dispersion of power stations will make a particularly strong contribution to the reduction of the need for power supplies in the peak load and sub peak demand periods, since it is then that energy prices will be highest and it is then, too, that it is viable to use energy from one's own storage facilities or to shift the time when selected needs are to be satisfied.

Ultimately, in SC2 the total expected gross production by generators supplying energy through the highest-voltage and high-voltage networks and participating in trade at the wholesale market level is lower by 4.7%, 10.0%, 15.2% and 20.0%, respectively, in 2020, 2025, 2030 and 2035 (Attachment 1)[2].

In all the calculations for the scenarios and options, the following assumptions are adopted concerning the electricity generation methods, which determine the CO_2 emission levels:

1. The CO_2 emission intensity under the guidance [8] for reporting in 2017, based on the statistical data for 2014 (Table 1).

Table 1. The CO_2 emission intensity under the guidance for reporting in 2017, based on the statistical data for 2014.

Description		**Calorific value**	**kg CO_2/GJ in fuel**	**kg CO_2/MWh in fuel**
Thermal power stations plants and CHP plants	Hard coal [MJ/kg]	21.77	92.3	332.3
	Lignite [MJ/kg]	8.12	110.8	398.8
Industrial CHP plants	Hard coal [MJ/kg]	22.81	94.7	340.9
Other indicators	Natural gas [MJ/m^3]	36.30	56.1	202.0
	Heating oil [MJ/kg	40.40	77.4	278.6
	Firewood [MJ/kg]	15.60	112.0	403.2
	Biogas [MJ/kg]	50.40	54.6	196.6

Source: *Calorific values (CV) and CO_2 emission factors (EF) in 2014 for reporting under the Emission Allowance Trading Scheme for 2017,* KOBiZE 2016.

[2] The detailed results of analyses are given in Attachments.

2. Average net efficiencies of power stations and their emission intensity, own estimates based on references [6, 7, 9, 10] (Table 2).

Table 2. Average net efficiencies of power stations and their emission intensity.

Electricity generator	Net efficiency [%]	Emission intensity of electricity [kg/MWh]
New 1,000 MW class hard-coal fired unit	45.6	730
New 450 MW class lignite-fired unit	41.6	960
Other existing hard-coal fired units	38.5	860
1,000 MW class lignite-fired unit	45.2	880
Other existing lignite-fired units	38.8	1030
600 MW class combined cycle gas-fired unit	57.0	350
Gas-fired units	47.0	430
Biomass-fired heat and power plants	65.0	620 (0)[3]
Existing hard-coal fired CHP plants	70.0	480
Existing gas-fired CHP plants	72.0	280
Modernised 200 MW class hard-coal fired unit, baseload operation	41.0	810
Modernised 200 MW class hard-coal fired unit, peak load operation	38.0	880
Industrial CHP plants	48.0	690
Nuclear power station	37.0	0
Net imports[4]	98.0	0

3. Modernised 200 MW class will initially achieve the average efficiency of 41%, under the assumption of uniform baseload operation. Later, it will fall to 38%, as a result of interrupted operation in the periods of sub peak and peak capacity demand.
4. Dispersed capacity providers are a mix of dispositional stations (biomass, water, different gases, coal, waste-derived fuel) and those with a fluctuating character (solar and wind energies), under the assumption of the growing ability to store electricity in correlation with the development of electromobility as well as the use of the energy generated for heating purposes. The following mix is adopted for assessing CO_2 emissions from these generators: 50% zero-emission RES, 20% zero-emission biomass in

[3] Zero emissions are adopted in the calculations.
[4] It is assumed that the possible greenhouse gas emissions related to electricity generation are attributed to the supplier country rather than the user country.

the balance, 20% coal and coke mostly burned in CHP plants with 30% efficiency for electricity and 10% heating oil with 30% efficiency. The average operating time for such a mix of dispersed generators is assumed at 1,000 hours/year for active generators in the periods of peak load needs of the system (25% of its capacity) and 4,000 for active baseload generators (75% of the capacity), i.e. on average 3,250 hours/year. The resultant emission intensity was estimated at 148 kg CO_2/MWh of net production.

Scenario 1 (central), option 1 (wind and solar)

It is assumed that the importance of hard coal will be maintained – due to the construction of 1,000 MW class units, off-shore wind-based generation will develop intensively and so will solar generation. Nuclear generation can also develop. After 2025 no investment projects in large coal-fired units will be launched when awaiting the first 1500 MW nuclear unit at the end of the period considered. The peak demand and capacity reserves will be covered by gas-fired generators and interconnectors with capacity of up to 4.2 GW (Attachment 2).

In option 1 of scenario 1, there will be a relatively quick reduction of the emission intensity and a systematic reduction of the absolute CO_2 emission levels related to electricity generation. **The total emissions in the period from 2021 to 2035 will be about 1,518 million tonnes of CO_2. The average emission intensity in the PPS will fall from about 813 kg CO_2/MWh in 2015 to about 448 kg CO_2/MWh in 2035**.

Scenario 1 (central), option 2 (nuclear)

It is assumed that the importance of hard coal will be maintained through the consistent modernisation of the existing 200+ MW class units as a bridging technology for the shift to the intensive development of nuclear power station. The first 1,000 MW class nuclear unit will appear in the early 2030s and every year two units will be set in operation. Investments in large coal-fired units will be dropped (apart from those currently at an advanced implementation stage). The development of large fluctuating renewable energy sources will be halted. Peak demand and capacity reserves will be covered by modernised 200+ MW coal-fired units, gas-fired units and interconnectors with capacity of up to 4.2 GW. In the late 2020s, the existing domestic assets will be under heavy load (Attachment 3).

In option 2 of scenario 1, the reduction of the emission factor will be slower, while the absolute emissions will remain at a stable level until nuclear units appear in the electricity balance. At this moment, the emission intensity will begin to fall faster, while the absolute emissions will begin to decrease. **The total emissions in the period from 2021 to 2035 will be about 1,681 million tonnes of CO_2; thus, they will be lower by about 163 million tonnes than those in option 1. The average emission intensity in the PPS will fall from about 813 kg CO_2/MWh in 2015 to about 397 kg CO_2/MWh in 2035. At the end of the period considered, the emission intensity will fall below the intensity in option 1, but it will be higher in the other years.**

Scenario 1 (central), option 3 (coal-based)

It is assumed that coal-fired units will be given priority when investment decisions are taken. This would entail the adoption of research hypotheses about new investments in large-scale 1,000 MW class coal-fired units, the use of modernised 200+ MW class units as well as the development of generation at CHP plants, which would also be partly coal-based.

Moreover, it is assumed that biomass-fired and wind stations will grow slightly. The peak demand and capacity reserves will be covered by modernised 200+ MW coal-fired units, gas-fired units and interconnectors with capacity of up to 4.2 GW (Attachment 4).

In option 3 of scenario 1, the emission intensity will be reduced more slowly, while the absolute emissions will remain at a stable level throughout the period considered. **The total emissions in the period from 2021 to 2035 will be about 1,789 million tonnes of CO_2; thus, they will be higher by about 271 million tonnes than those in option 1 and higher by about 108 million tonnes than those in option 2. The average emission intensity in the PPS will fall from about 813 kg CO_2/MWh in 2015 to about 642 kg CO_2/MWh in 2035**.

Scenario 2 (decentralised), option 1 (depleting the currently available coal resources)

It is assumed that dispersed generation will develop dynamically, involving all the consequences for the demand size and profile considered earlier. On the wholesale market, 200+ MW units, which will be consistently modernised and operate until their technical wear (without further modernisations), will play a significant role. Biomass-fired CHP plants will also be important, while the share of other large-scale RES installations (hereinafter referred to as “central RES”), cooperating with the PPS using transmission networks, will be slight. In this option, the existing conventional units will operate under heavy and growing load. The demand side response (DSR) and imports will be the main reserve sources. Breakdowns of the largest 1,000 MW class units, now under construction, and the loss of the capacity of thermal power units as a result of worsened cooling conditions will pose a special risk for the capacity balance. RES with their fluctuating availability will not entail such a risk (Attachment 5).

In qualitative terms, the emission reduction in option 1 of scenario 2 is comparable to the one in option 1 of scenario 1. **The absolute emissions will systematically fall throughout the period considered. The total emissions in the period from 2021 to 2035 will be about 1,540 million tonnes of CO_2. The average emission intensity in the PPS will fall from about 813 kg CO_2/MWh in 2015 to about 588 kg CO_2/MWh in 2035.**

Scenario 2 (decentralised), option 2 (with imports)

It is assumed that dispersed generation will develop dynamically, involving all the consequences for the demand size and profile considered earlier. Just as in option 1, on the wholesale market, modernised 200+ MW units and biomass-fired CHP plants will play a significant role, while the role of central RES cooperating with the PPS using transmission networks will be slight. In turn, the operation of coal-fired units will gradually be replaced in time with imports (in particular, to complement the capacity balance after the closedown of modernised power units in the initial part of the period considered). In addition to DSR, imports will also be the main source of peak load capacity. In this option, conventional units will be under moderate load; their operation should be appropriately more flexible, while electricity imports will indirectly substitute for part of natural gas imports by avoiding the need to use it in the operation of domestic gas-fired units (Attachment 6).

In option 2 of scenario 2, the emission reduction is significantly higher than the one in option 1 of scenario 2. **The absolute emissions will fall faster throughout the period considered. The total emissions in the period from 2021 to 2035 will be about 1,321 million tonnes of CO_2. The average emission intensity in the PPS will fall from about 813 kg CO_2/MWh in 2015 to about 415 kg CO_2/MWh in 2035**.

Scenario 2 (decentralised), option 3 (wind and solar)

It is assumed that dispersed generation will develop dynamically, involving all the consequences for the electricity demand level and its variations in time (its profile) considered earlier. Just as in options 1 and 2, on the wholesale market, modernised 200+ MW units and biomass-fired CHP plants will play a significant role. In turn, the role of imports will be limited by the growing share of central RES (while the same capacity of interconnectors as in option 2 will be maintained). These RES will also limit the operation of coal-fired units (among others, balancing the PPS needs after the modernised coal-fired units which will operate in the initial period are closed down). In this option, conventional units will be under moderate load; it would be important to ensure that they are able to change loads as flexibly as possible. In addition to DSR, imports will also be the main source of peak load capacity (Attachment 7).

In option 3, the average emission reduction will be the largest among all the considered options of scenario 2 and at the end of the period it will be comparable to (slightly higher than) the nuclear option in scenario 1. **The total emissions in the period from 2021 to 2035 will be about 1,269 million tonnes of CO_2. The average emission intensity in the PPS will fall from about 813 kg CO_2/MWh in 2015 to about 415 kg CO_2/MWh in 2035**.

Comparison of scenarios

A comparison of scenarios, including the individual options within them, clearly demonstrates that the most favourable solutions in terms of CO_2 emission reductions are offered by two options within the decentralised scenario, i.e. the one involving wind and solar and the import-based one. The coal-based and nuclear options within the centralised scenario are the least favourable ones; specifically, the nuclear one is such given the launch of nuclear power units in the distant future. The intermediate values are achievable for the option based on wind and solar within the centralised scenario and for the one involving the depletion of coal resources available, under the decentralised scenario (Attachment 8). **In the most favourable option (the decentralised one with a large share of RES), the total emissions in the period from 2021 to 2035 will be lower by 29% than their level in the option with the highest emissions (the centralised one with a large share of coal). This means that the average emissions would be lower by 16.9 million tonnes of CO_2/year, representing more than 10% of the 2015 emissions from the sector [11] .**

A very important factor which affects the demand for both electricity and electrical capacity is the way in which the national economy develops. This way is different in the particular scenarios. In this context, the options-based mix of electricity generation is of secondary importance. Therefore, the qualitative extent of the effect of the way in which the national economy develops on CO_2 emissions is presented here, by averaging the detailed cases, which were analysed earlier, of the PPS balancing mixes which would result from the policy of the introduction of the capacity market (Attachment 9).

An analysis of the average results of the scenarios indicates:

1. A much lower (by about 17%) average CO_2 emissions in the period from 2021 to 2035, related to the implementation of the socio-economic development according to scenario 2; moreover, the greatest difference of about 21–23% will come after 2028.
2. The limitation of the differences in the emissions intensity between the scenarios at the end of the period considered in case large RES capacity and/or nuclear capacity is set in operation in the implementation of scenario 1.

Conclusion

1. Given the absence of a verified comprehensive national energy policy (which would specify at least the tasks to be set for the proposed capacity market or the impact of the development of electromobility on the PPS), the analyses presented here can only be regarded as qualitative ones.
2. The CO_2 emission levels will significantly depend on the levels and time characteristics (the variability profile) of the electricity demand as long as generators based on the combustion of fossil fuels have a significant share in the PPS.
3. The level of CO_2 emissions as a result of the introduction of the proposed capacity market will depend, in particular, on its effect on the mix of the generation assets operating over long periods, i.e. to satisfy the baseload demand of the PPS. The mix of power stations in operation to balance the variable capacity needs of the PPS will have a relatively lesser effect in light of the short operating times of these generators.
4. **A particularly adverse effect (from the point of view of CO_2 emissions) is the use of the capacity market to build new coal-fired power stations intended to operate in order to meet the baseload demand of the PPS, while using, at the same time, old (modernised) units to balance the variable needs (sub peak or those compensating for the loss of capacity from other sources).**
5. In addition to the variable demand, the need to be able to balance the variable capacity needs relates, in particular, to units with large, concentrated capacity (the 1,000 MW class), organised in large complexes – power stations (with their total capacity of the order of 4–5 GW) and, in general in summer periods, units based on thermal circuits which require the cooling capacity, as well as wind and solar energy.
6. **Decentralisation of the PPS, involving the use of ICT and automation and a relevant legal regulation, makes it possible with large probability to gain substantial benefits in the process of balancing the capacity of the PPS by triggering prosumer activities, i.e. using the many opportunities for generation and demand (volume and profile) management, as well as synergies with other economic processes, such as electromobility, heating or waste disposal**.

7. Imports are an attractive means of balancing the variable demand for electrical capacity in the PPS. In terms of prices, imports are highly competitive with respect to large-scale domestic stations on the electricity market and cause their marginalisation. In contrast, imports are significantly less competitive against domestic dispersed generation.

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Attachments

Attachment 1

The expected total gross energy production by units supplying energy through highest-voltage and high-voltage networks

SC1 = scenario 1 (own assumptions)				SC2 = scenario 2 (own assumptions)							
Year	Forecast gross energy production [TWh]	Forecast net energy production [TWh]	Forecast network losses [TWh]	Dispersed capacity with accumulation [MW]	Peak load reduction by users' behaviour [%]	Baseload reduction by users' investments [%]	Trans-mission system demand [TWh]	Forecast network losses [TWh]	Forecast net energy production on the wholesale market [TWh]	Forecast gross energy production on the wholesale market [TWh]
2017	164	150	9.8	300	0%	0.0%	139	9.1	149	162
2018	166	152	9.9	672	0.6%	0.3%	140	8.9	148	162
2019	168	154	10.0	1,044	1.1%	0.6%	140	8.8	148	162
2020	170	156	10.1	1,417	1.7%	0.8%	140	8.6	148	162
2021	172	158	10.3	1,789	2.2%	1.1%	140	8.5	149	162
2022	174	160	10.4	2,161	2.8%	1.4%	140	8.3	149	162
2023	176	161	10.5	2,533	3.3%	1.7%	141	8.2	149	162
2024	178	163	10.6	2,906	3.9%	1.9%	141	8.1	149	162
2025	180	165	10.7	3,278	4.4%	2.2%	141	7.9	149	162
2026	182	167	10.9	3,650	5.0%	2.5%	142	7.8	149	162
2027	184	169	11.0	4,022	5.6%	2.8%	142	7.6	149	161
2028	186	171	11.1	4,394	6.1%	3.1%	142	7.5	150	162
2029	188	172	11.2	4,767	6.7%	3.3%	142	7.3	150	162
2030	190	174	11.3	5,139	7.2%	3.6%	143	7.2	150	161
2031	192	176	11.4	5,511	7.8%	3.9%	143	7.0	150	161
2032	194	178	11.6	5,883	8.3%	4.2%	143	6.9	150	161
2033	196	180	11.7	6,256	8.9%	4.4%	143	6.7	150	160
2034	198	182	11,8	6,628	9.4%	4.7%	143	6.6	150	160
2035	200	183	11.9	7,000	10.0%	5.0%	144	6.5	150	160

Attachment 2

The resultant emission intensity in scenario 1 (central), option 1 – wind and solar

Year	Assumed capacity decreases and additions [GW]									
	Hard coal-fired 1,000 MW units	Lignite-fired 450 MW unit	Existing hard coal-fired power plants	Existing lignite-fired power plants	Combined cycle gas-fired units	Gas-fired unit	Nuclear power plant	Wind and solar units	CO_2 emissions [million tonnes]	Resultant CO_2 emission intensity [kg/MWh]
2021	3.8	0.45	–5.3	–2.0	1.55	0	0	3.3	115.7	732
2022	3.8	0.45	–5.6	–2.3	1.55	0	0	4.5	115.0	720
2023	3.8	0.45	–6.0	–2.6	2.15	0	0	6.1	112.6	697
2024	4.8	0.45	–6.5	–2.8	2.75	0	0	7.6	109.8	671
2025	4.8	0.45	–7.0	–3.0	2.75	0	0	9.1	107.4	656
2026	4.8	0.45	–7.5	–3.4	2.75	0.2	0	10.7	106.6	638
2027	5.8	0.45	–8.5	–4.4	2.75	0.4	0	12.2	104.2	617
2028	6.8	0.45	–9.5	–4.9	2.75	0.6	0	13.7	102.4	600
2029	6.8	0.45	–10.0	–5.8	2.75	0.8	0	15.3	99.4	576
2030	7.8	0.45	–11.0	–6.3	3.35	1.0	0	16.8	95.6	547
2031	7.8	0.45	–11.8	–6.6	3.35	1.2	0	18.3	93.3	530
2032	7.8	0.45	–12.1	–6.7	3.35	1.4	0	19.8	92.3	519
2033	7.8	0.45	–12.5	–7.0	3.35	1.6	0	21.3	91.4	508
2034	7.8	0.45	–13.0	–7.2	3.35	1.8	0	22.8	90.4	497
2035	7.8	0.45	–13.4	–7.5	3.35	2.0	1.5	24.3	82.1	448

Attachment 3

The resultant emission intensity in scenario 1 (central), option 2 – nuclear

Year	Assumed capacity decreases and additions [GW]										
	Hard coal-fired 1,000 MW unit	Lignite-fired 450 MW unit	Existing hard coal-fired power plants	Existing lignite-fired power plants	Combined cycle gas-fired units	Gas-fired unit	Modernised hard coal-fired units	Nuclear power plant	Wind and solar units	CO_2 emissions [million tonnes]	Resultant CO_2 emission intensity [kg/MWh]
2021	3.8	0.45	–5.3	–2.0	1.55	0	4.3	0	1.5	116.9	740
2022	3.8	0.45	–5.6	–2.3	1.55	0	4.8	0	1.8	118.2	740
2023	3.8	0.45	–6.0	–2.6	1.55	0	5.5	0	2.1	119.2	737
2024	3.8	0.45	–6.5	–2.8	1.55	0	6.1	0	2.4	120.1	736
2025	3.8	0.45	–7.0	–3.0	1.55	0	6.7	0	2.7	120.8	731
2026	3.8	0.45	–7.5	–3.4	1.55	0.2	7.7	0	3.0	120.1	720
2027	3.8	0.45	–8.5	–4.4	1.55	0.4	8.7	0	3.3	120.4	713
2028	3.8	0.45	–9.5	–4.9	1.55	0.6	9.6	0	3.6	121.4	712
2029	3.8	0.45	–10.0	–5.8	1.55	0.8	10.7	0	3.9	121.3	703
2030	3.8	0.45	–11.0	–6.3	1.55	1.0	11.6	0	4.2	121.4	697
2031	3.8	0.45	–11.8	–6.6	1.55	1.2	10.7	0	4.5	118.8	674
2032	3.8	0.45	–12.1	–6.7	1.55	1.4	9.7	2.0	4.8	109.	618
2033	3.8	0.45	–12.5	–7.0	1.55	1.6	8.7	4.0	5.1	96.9	539
2034	3.8	0.45	–13.0	–7.2	1.55	1.8	7.7	6.0	5.4	83.4	460
2035	3.8	0.45	–13.4	–7.5	1.55	2.0	6.7	8.0	5.7	72.7	397

Attachment 4

The resultant emission intensity in scenario 1 (central), option 3 – coal-based

Year	Assumed capacity decreases and additions [GW]											
	Hard coal-fired 1,000 MW unit	Lignite-fired 450 MW unit	Existing hard coal-fired power plants	Existing lignite-fired power plants	Combined cycle gas-fired units	Gas-fired unit	Biomass-fired CHP plants	Hard coal-fired heat and power plant	Modernised hard coal-fired units	Wind and solar units	CO_2 emissions [million tonnes]	Resultant CO_2 emission intensity [kg/MWh]
2021	3.8	0.45	−5.3	−2.0	1.55	0	0	0	4.3	1.5	117.0	740
2022	3.8	0.45	−5.6	−2.3	1.55	0	0	0	4.8	1.6	118.6	743
2023	3.8	0.45	−6.0	−2.6	1.55	0	0.1	0.2	5.5	1.7	119.5	740
2024	3.8	0.45	−6.5	−2.8	1.55	0	0.2	0.4	6.1	1.8	120.4	736
2025	3.8	0.45	−7.0	−3.0	1.55	0	0.3	0.6	6.7	1.9	121.0	733
2026	4.8	0.45	−7.5	−3.4	1.55	0.2	0.3	0.6	7.7	2.0	120.5	721
2027	4.8	0.45	−8.5	−4.4	1.55	0.4	0.4	0.8	8.7	2.1	119.7	709
2028	5.8	0.45	−9.5	−4.9	1.55	0.6	0.4	0.8	9.6	2.2	119.0	696
2029	5.8	0.45	−10.0	−5.8	1.55	0.8	0.6	1.0	10.7	2.3	119.5	693
2030	6.8	0.45	−11.0	−6.3	1.55	1.0	0.6	1.0	11.6	2.4	120.6	692
2031	6.8	0.45	−11.8	−6.6	1.55	1.2	0.8	1.2	10.7	2.5	117.8	668
2032	7.8	0.45	−12.1	−6.7	1.55	1.4	0.8	1.2	9.7	2.6	120.1	676
2033	7.8	0.45	−12.5	−7.0	1.55	1.6	1.0	1.4	8.7	2.7	119.7	665
2034	7.8	0.45	−13.0	−7.2	1.55	1.8	1.0	1.4	7.7	2.8	117.6	647
2035	8.8	0.45	−13.4	−7.5	1.55	2.0	1.2	1.6	6.7	2.9	118.1	642

Attachment 5

The resultant emission intensity in scenario 2 (decentralised), option 1 – depleting the currently available coal resources

Year	Assumed capacity decreases and additions [GW]												
	Hard coal-fired 1,000 MW unit	Lignite-fired 450 MW unit	Existing hard coal-fired power plants	Existing lignite-fired power plants	Combined cycle gas-fired units	Gas-fired unit	Biomass-fired CHP plants	Modernised hard coal-fired units	Wind and solar units	Additional dispersed peak load units	Additional dispersed baseload units	CO_2 emissions [million tonnes]	Resultant CO_2 emission intensity [kg/MWh]
2021	3.8	0.45	–5.3	–2.0	1.55	0	0	4.3	1.5	0.2	1.6	109.6	735
2022	3.8	0.45	–5.6	–2.3	1.55	0	0	4.8	0.2	0.3	1.9	109.7	735
2023	3.8	0.45	–6.0	–2.6	1.55	0	0.1	5.5	0.2	0.4	2.2	108.9	730
2024	3.8	0.45	–6.5	–2.8	1.55	0	0.2	6.1	0.2	0.5	2.4	108.2	725
2025	3.8	0.45	–7.0	–3.0	1.55	0	0.3	6.7	0.2	0.6	2.7	107.6	721
2026	3.8	0.45	–7.5	–3.4	1.55	0.2	0.4	7.7	0.2	0.7	3.0	106.6	714
2027	3.8	0.45	–8.5	–4.4	1.55	0.4	0.5	8.9	0.2	0.7	3.3	104.8	701
2028	3.8	0.45	–9.5	–4.9	1.55	0.6	0.6	9.6	0.2	0.8	3.6	104.2	694
2029	3.8	0.45	–10.0	–5.8	1.55	0.8	0.7	10.7	0.2	0.9	3.8	102.6	682
2030	3.8	0.45	–11.0	–6.3	1.55	1.0	0.8	11.6	0.2	1.0	4.1	101.9	677
2031	3.8	0.45	–11.8	–6.6	1.55	1.2	0.9	10.7	0.2	1.1	4.4	100.9	672
2032	3.8	0.45	–12.1	–6.7	1.55	1.4	1.0	9.7	0.4	1.2	4.7	98.5	655
2033	3.8	0.45	–12.5	–7.0	1.55	1.6	1.3	8.7	0.4	1.3	5.0	95.3	634
2034	3.8	0.45	–13.0	–7.2	1.55	1.8	1.6	7.7	0.4	1.4	5.2	92.5	615
2035	3.8	0.45	–13.4	–7.5	1.55	2.0	1.7	6.7	0.4	1.5	5.5	88.6	588

Attachment 6

The resultant emission intensity in scenario 2 (decentralised), option 2 – with imports

Year	Assumed capacity decreases and additions [GW]													
	Hard coal-fired 1,000 MW unit	Lignite-fired 450 MW unit	Existing hard coal-fired power plants	Existing lignite-fired power plants	Combined cycle gas-fired units	Gas-fired unit	Biomass-CHP plants	Modernised hard coal-fired units	Wind and solar units	Additional dispersed peak load units	Additional dispersed baseload units	Net imports	CO_2 emissions [million tonnes]	Resultant CO_2 emission intensity [kg/MWh]
2021	3.8	0.45	–5.3	–2.0	1.55	0	0	4.3	1.5	0.2	1.6	1.0	107.7	721
2022	3.8	0.45	–5.6	–2.3	1.55	0	0	4.8	0.2	0.3	1.9	2.0	105.6	708
2023	3.8	0.45	–6.0	–2.6	1.55	0	0.1	5.5	0.2	0.4	2.2	3.0	102.7	689
2024	3.8	0.45	–6.5	–2.8	1.55	0	0.2	6.1	0.2	0.5	2.4	4.0	100.1	671
2025	3.8	0.45	–7.0	–3.0	1.55	0	0.3	6.7	0.2	0.6	2.7	5.0	97.3	652
2026	3.8	0.45	–7.5	–3.4	1.55	0.2	0.4	7.7	0.2	0.7	3.0	6.0	94.1	631
2027	3.8	0.45	–8.5	–4.4	1.55	0.4	0.5	8.7	0.2	0.7	3.3	7.0	91.0	610
2028	3.8	0.45	–9.5	–4.9	1.55	0.6	0.6	9.6	0.2	0.8	3.6	8.0	89.4	595
2029	3.8	0.45	–10.0	–5.8	1.55	0.8	0.7	10.7	0.2	0.9	3.8	9.0	86.1	573
2030	3.8	0.45	–11.0	–6.3	1.55	1.0	0.8	11.6	0.2	1.0	4.1	10.0	83.9	559
2031	3.8	0.45	–11.8	–6.6	1.55	1.2	0.9	10.7	0.2	1.1	4.4	11.0	83.3	555
2032	3.8	0.45	–12.1	–6.7	1.55	1.4	1.0	9.7	0.4	1.2	4.7	11.0	79.6	529
2033	3.8	0.45	–12.5	–7.0	1.55	1.6	1.3	8.7	0.4	1.3	5.0	11.0	71.4	475
2034	3.8	0.45	–13.0	–7.2	1.55	1.8	1.6	7.7	0.4	1.4	5.2	11.0	66.4	443
2035	3.8	0.45	–13.4	–7.5	1.55	2.0	1.7	6.7	0.4	1.5	5.5	11.0	62.3	415

Attachment 7

The resultant emission intensity in scenario 2 (decentralised), option 3 – wind and solar

Year	Assumed capacity decreases and increases [GW]													
	Hard coal-fired 1,000 MW unit	Lignite-fired 450 MW unit	Existing hard coal-fired power plants	Existing lignite-fired power plants	Combined cycle gas-fired units	Gas-fired unit	Biomass-fired CHP plants	Modernised hard coal-fired units	Wind and solar units	Additional dispersed peak load units	Additional dispersed baseload units	Net imports	CO_2 emissions [million tonnes]	Resultant CO_2 emission intensity [kg/MWh]
2021	3.8	0.45	–5.3	–2.0	1.55	0	0	4.3	1.5	0.2	1.6	1	107.7	722
2022	3.8	0.45	–5.6	–2.3	1.55	0	0	4.8	2.0	0.3	1.9	2	105.6	708
2023	3.8	0.45	–6.0	–2.6	1.55	0	0.1	5.5	2.5	0.4	2.2	3	102.7	688
2024	3.8	0.45	–6.5	–2.8	1.55	0	0.2	6.1	3.0	0.5	2.4	4	98.7	662
2025	3.8	0.45	–7.0	–3.0	1.55	0	0.3	6.7	3.5	0.6	2.7	5	92.9	622
2026	3.8	0.45	–7.5	–3.4	1.55	0.2	0.4	7.7	4.0	0.7	3.0	6	88.9	596
2027	3.8	0.45	–8.5	–4.4	1.55	0.4	0.5	8.7	4.5	0.7	3.3	7	84.4	566
2028	3.8	0.45	–9.5	–4.9	1.55	0.6	0.6	9.6	5.0	0.8	3.6	8	83.0	553
2029	3.8	0.45	–10.0	–5.8	1.55	0.8	0.7	10.7	5.5	0.9	3.8	9	80.0	533
2030	3.8	0.45	–11.0	–6.3	1.55	1.0	0.8	11.6	6.0	1.0	4.1	10	77.4	516
2031	3.8	0.45	–11.8	–6.6	1.55	1.2	0.9	10.7	6.5	1.1	4.4	11	73.9	492
2032	3.8	0.45	–12.1	–6.7	1.55	1.4	1.0	9.7	7.0	1.2	4.7	11	72.3	481
2033	3.8	0.45	–12.5	–7.0	1.55	1.6	1.3	8.7	7.5	1.3	5.0	11	70.6	470
2034	3.8	0.45	–13.0	–7.2	1.55	1.8	1.6	7.7	8.0	1.4	5.2	11	68.1	453
2035	3.8	0.45	–13.4	–7.5	1.55	2.0	1.7	6.7	8.5	1.5	5.5	11	62.4	415

Attachment 8

The resultant emission intensity – a comparison of scenarios and options

Year	S1 O1		S1 O2		S1 O3		S2 O1		S2 O2		S2 O3	
	Wind and solar		Nuclear		Coal-based		Depleting coal resources		Imports		Wind and solar	
	CO_2 emissions [million tonnes]	Resultant CO_2 emission intensity [kg/MWh]	CO_2 emissions [million tonnes]	Resultant CO_2 emission intensity [kg/MWh]	CO_2 emissions [million tonnes]	Resultant CO_2 emission intensity [kg/MWh]	CO_2 emissions [million tonnes]]	Resultant CO_2 emission intensity [kg/MWh]	CO_2 emissions [million tonnes]	Resultant CO_2 emission intensity [kg/MWh]	CO_2 emissions [million tonnes]	Resultant CO_2 emission intensity [kg/MWh]
2021	115.7	732	116.9	740	**117.0**	**740**	109.6	735	107.7	721	**107.7**	**722**
2022	115.0	720	118.2	740	**118.6**	**743**	109.7	735	105.6	708	**105.6**	**708**
2023	112.6	697	119.2	737	**119.5**	**740**	108.9	730	102.7	689	**102.7**	**688**
2024	109.8	671	120.1	736	**120.4**	**736**	108.2	725	100.1	671	**98.7**	**662**
2025	107.4	656	120.8	731	**121.0**	**733**	107.6	721	97.3	652	**92.9**	**622**
2026	106.6	638	120.1	720	**120.5**	**721**	106.6	714	94.1	631	**88.9**	**596**
2027	104.2	617	120.4	713	**119.7**	**709**	104.8	701	91.0	610	**84.4**	**566**
2028	102.4	600	121.4	712	**119.0**	**696**	104.2	694	89.4	595	**83.0**	**553**
2029	99.4	576	121.3	703	**119.5**	**693**	102.6	682	86.1	573	**80.0**	**533**
2030	95.6	547	121.4	697	**120.6**	**692**	101.9	677	83.9	559	**77.4**	**516**
2031	93.3	530	118.8	674	**117.8**	**668**	100.9	672	83.3	555	**73.9**	**492**
2032	92.3	519	109.0	618	**120.1**	**676**	98.5	655	79.6	529	**72.3**	**481**
2033	91.4	508	96.9	539	**119.7**	**665**	95.3	634	71.4	475	**70.6**	**470**
2034	90.4	497	83.4	460	**117.6**	**647**	92.5	615	66.4	443	**68.1**	**453**
2035	82.1	448	72.7	397	**118.1**	**642**	88.6	588	62.3	415	**62.4**	**415**
Total 2021–2035	**1,518.2**	**X**	**1,680.6**	**X**	**1,789.1**	**X**	**1,539.9**	**X**	**1,320.9**	**X**	**1,268.6**	**X**

Attachment 9

The resultant emission intensity – averaged values

Year	Averaged scenario 1		Averaged scenario 2		Differences between averaged scenarios			
					Absolute = S1 – S2		Relative = (S1 – S2)/S1	
	CO_2 emissions [million tonnes]	Resultant CO_2 emission intensity [kg/MWh]	CO_2 emissions [million tonnes]	Resultant CO_2 emission intensity [kg/MWh]	CO_2 emissions [million tonnes]	Resultant CO_2 emission intensity [kg/MWh]	CO_2 emissions [%]	Resultant CO_2 emission intensity [%]
2015	122.3	812	122.3	812	0.0	0	0.0%	0.0%
2021	116.5	737	108.3	726	8.2	11	7.0%	1.5%
2022	117.3	734	107.0	717	10.3	17	8.8%	2.4%
2023	117.1	725	104.8	702	12.3	22	10.5%	3.1%
2024	116.8	714	102.3	686	14.4	28	12.4%	4.0%
2025	116.4	707	99.3	665	17.1	42	14.7%	5.9%
2026	115.7	693	96.5	647	19.2	46	16.6%	6.6%
2027	114.8	680	93.4	626	21.4	54	18.6%	7.9%
2028	114.3	669	92.2	614	22.1	55	19.3%	8.3%
2029	113.4	657	89.6	596	23.8	61	21.0%	9.3%
2030	112.5	645	87.7	584	24.8	61	22.0%	9.5%
2031	110.0	624	86.0	573	23.9	51	21.8%	8.2%
2032	107.1	604	83.5	555	23.7	49	22.1%	8.2%
2033	102.7	571	79.1	526	23.6	44	23.0%	7.8%
2034	97.1	535	75.7	504	21.5	31	22.1%	5.8%
2035	91.0	496	71.1	473	19.9	23	21.8%	4.6%
Total 2021–2035	**1,662.6**	**X**	**1,376.5**	**X**	**286.2**	**X**	**17.2%**	**X**