Gerard Wynn, Energy Finance Consultant
Paolo Coghe, International Financial Economist
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How to Create a Profitable Polish Electricity System

PGE Can Set More Aggressive Renewables Goals, Develop Coal Phaseout Strategy

Executive Summary

In this report, we consider the profitability of Poland's electricity sector through the example of the country's biggest electric utility, majority state-owned Polska Grupa Energetyczna S.A. (PGE). We focus exclusively on PGE's generation business, putting aside supply and distribution. Our goal was to understand better how quickly the company must transform itself into a low-carbon company to remain viable.

At present, PGE's power generation is dominated by hard coal and lignite, making it one of the most carbon-intensive energy companies in Europe. The company is also completing a high-carbon spending spree, despite long-term EU policy and energy market trends toward low-carbon. Under its present strategic plan, the utility has invested PLN 27.9 billion in acquiring, renovating or building coal and lignite power plants, as well as a handful of gas-fired combined heat and power plants—96% of the total PLN 29.2 billion (€7 billion, $8 billion) invested in electricity generation from 2015-2018.[1] Renewables accounted for just PLN 1.3 billion.

PGE has shown signs of change, recently announcing new renewable energy and gas generation plans for 2025 and 2030. But it has announced no major plans for coal or lignite decommissioning. As a result, it is now less ambitious than the Polish government's new National Energy and Climate Plan (NECP), which details the country's planned energy mix through 2030. The government has also published a draft Polish Energy Plan for 2040 (PEP40), extending the NECP for an additional decade.

We analysed PGE's profitability according to three broad scenarios through 2030: PGE's present plans; the government's new NECP; and bringing forward to 2030 the government's PEP40 goal to halve coal and lignite capacity by 2040. We called these scenarios: Business as Usual (BAU), NECP and Halving Coal. Clearly, the NECP scenario should be entirely achievable, as it is the government's benchmark. We introduced the Halving Coal scenario as an example of a step further.

We applied these scenarios to PGE in 2030, in a way that maintained the company's total electricity generation. In the BAU scenario, wind and solar rise to 6 gigawatts (GW), from less than 1GW today, while coal and lignite are unchanged. In the NECP scenario, wind and solar rise to 11GW, while coal and lignite fall by nearly a fifth. In the Halving Coal scenario, wind and solar rise to 22GW, while coal and lignite more than halve.

[1] In this report, we use an exchange rate of 1 Polish zloty (PLN) to $0.26 and €0.24

Some of PGE's investments are likely to be written off, as its coal power plants will be loss-making

We measure profitability according to two standard measures: earnings before interest, taxes, depreciation and amortisation (EBITDA), and net income. EBITDA takes account of short-term cash costs such as fuel and carbon, while net income accounts for full costs, including capital expenditures to build new power plants. We measured profitability by technology on average, rather than at the level of individual power plants. In addition to a range of other assumptions, we consider two carbon price outlooks: a low-carbon price rising from the present forward curve to €30 per tonne of carbon dioxide emissions in 2030, and a high carbon price outlook rising to €40 per tonne.

Main Findings

1. Our findings highlight what we believe was PGE's strategic error to invest PLN 28 billion in conventional generation from 2015-2018.

    - Under all three scenarios, we find that the profitability of PGE's coal and lignite generation is highly sensitive to carbon prices, and the viability of coal is especially precarious. Some of PGE's present investments appear highly likely to be written off, as these coal power plants will be loss-making in the near term.

    - Our fossil fuel profit estimates include more than PLN 20 billion in capacity payments that we calculate will be paid to PGE's thermal generation (coal, gas, combined heat and power/CHP and lignite) cumulatively through 2030 under the terms of Poland's new capacity market. Without this scheme, whose official goal is to safeguard Poland's security of electricity supply, we find that coal generation is on average unprofitable from 2022, even under a low-carbon price outlook.

2. Looking forward, coal and lignite profitability falls rapidly or disappears completely over the course of this decade.

    - Under our low carbon price outlook (€30 per tonne in 2030), coal EBITDA is close to zero from 2026 onward. Coal net income is negative from 2029. Lignite earnings are slightly higher, but only account for a small fraction of PGE's total EBITDA from 2026 onward; today it accounts for more than half of power generation. These findings highlight why PGE urgently needs to invest in higher profit, low-carbon generation.

        - In our BAU scenario, total EBITDA grows 22%, driven entirely by investment in renewables, but net income falls 12%. Net debt divided by EBITDA (a core ratio indicating whether debt levels are sustainable) rises to 2.0 times in 2030, from 0.5 in 2021, to finance new renewables and conventional capacity, and to finance air quality upgrades for conventional generation.

    - In the NECP scenario, much higher investment in renewables drives 47% EBITDA growth overall, while net income is flat. Net debt to EBITDA rises to 2.7 times.

    - In the Halving Coal scenario, total EBITDA doubles, while net income rises 21%. Net debt to EBITDA rises to 3.3 times in 2030.

- Our higher carbon price outlook (€40 per tonne in 2030) is within current analyst forecasts and highlights the risks to PGE's present strategy. Both coal and lignite now have negative EBITDA and negative net income from 2026, despite massive capacity payments.

    - Under the BAU scenario, renewables investments are not enough to counter losses in the fossil fuel business, and total EBITDA falls 29% from 2021-2030. Net income falls 68%. Lower EBITDA undermines the net debt to EBITDA ratio, which now rises to 3.5 times in 2030, from 0.5 times in 2021.

    - Under the more ambitious NECP scenario, the greater investment in renewables is enough to drive 5% EBITDA growth overall. This finding underscores why we believe that PGE should launch a more ambitious low-carbon transition than its present plans, at least to match the government's NECP. Total net income still almost halves. Net debt to EBITDA is 4.4 times in 2030.

    - Under our Halving Coal scenario, total EBITDA rises nearly 70%, and total net income falls just 12%. Net debt to EBITDA is 4.7 times in 2030.

3. PGE's commitment to fossil fuels increases its exposure to regulatory and environment-related risks that jeopardise cash flows further. Some of these regulatory risks only have a downside, such as tougher air pollution regulations, a coal phaseout, or that lenders stop financing fossil fuel generation. Such risks will increase PGE's cost of capital in the first scenario compared with the greener second and third scenarios.

Recommendations

We conclude that PGE must invest urgently today in profitable, cash-generating renewable power capacity to replace flagging cash generation from its coal and lignite businesses. It is unfortunate that PGE must make these large investments on the back of significant coal and lignite spending, which has left it more indebted and with a legacy of potentially under-performing assets. But the direction of EU energy and climate policy has been clear since the introduction of the EU emissions trading scheme (EU ETS) in 2005.

Our findings indicate that coal will be barely profitable, or loss-making, in the second half of the 2020s

We make the following recommendations:

1. The Polish government, as PGE's majority shareholder, should explicitly reject a proposed new lignite mine at Złoczew, which would extend lignite generation at Bełchatów, Europe's biggest coal power plant, into the 2050s. Rejecting this proposal, which remains one of PGE's three core "strategic options," would show investors and other stakeholders that PGE is embarking on a transformation. Without a new mine at Złoczew, the last, most modern, units Bełchatów would have to close by around 2035, an end date compatible with our findings of declining profitability.

2. PGE should invest today to start exiting hard coal power generation after 2025, with more aggressive renewables investment plans than announced to date. At present, PGE plans only to review its coal and lignite portfolio in 2025, when coal ceases to be eligible for new payments under the country's capacity market. Our findings indicate that coal on average will be barely profitable, or loss-making, in the second half of the 2020s. The company must invest today to source alternative cash generation.

3. PGE should prepare now to exit all lignite power generation after 2030. Lignite today accounts for more than half of all PGE's generation, but we find it is loss-making on average long before 2030 under a higher carbon price outlook. Even under a low-carbon price outlook, lignite will only account for a small fraction of PGE profits after 2025.

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Introduction

Poland is historically one of Europe's most coal and carbon-intensive countries, reflecting abundant domestic coal resources, including both hard coal and brown coal, called lignite. These resources have led to domestic energy policy priorities including to support mining jobs and maintain energy independence. Successive Polish governments have resisted a rapid transition to low-carbon energy. This position has become increasing untenable, as a result of rising carbon prices; increasing competitiveness of low-carbon energy sources; and Poland's gradual depletion of domestic coal, which has been partly substituted by imports, especially from Russia.

A near-term transition from coal appears inevitable, towards zero-coal generation by the mid-2030s. However, Poland could seek to delay such a transition, for example to develop new coal mines and extend coal generation into the 2050s. That approach would probably burden the state and energy consumers with the bailout costs of a subsequent mandated, premature retirement of coal mines and power plants.

The debate over Poland's next steps is coming to a head, after the country published in December 2019 the final version of its National Energy and Climate Plan (NECP), which sets out the country's energy mix targets for 2030, as required under European Union law.[2] In addition, the government has published a draft Polish Energy Policy, or PEP40, extending the NECP targets to 2040.[3]

Poland's biggest utility, majority state-owned PGE, has recently signalled a new commitment to renewables, with more ambitious targets for example for offshore wind and solar PV. The company states that it is presently preparing a 1 gigawatt (GW) offshore wind project to bid in offtake tenders, and is targeting a total 2.5 GW of offshore wind and 2.5 GW of solar PV by 2030.

PGE has signalled a new commitment to renewables, with more ambitious targets for offshore wind and solar

However, PGE still lags the government's NECP, in particular because it has no plans yet for major coal and lignite decommissioning in the 2020s. PGE to date has only said that it will "review" its coal and lignite portfolio in 2025, when coal ceases to be eligible for new payments under the country's capacity market. By contrast, the NECP anticipates a 15% reduction in coal and lignite generating capacity in 2030 compared with 2020. Given the NECP is the Polish government's benchmark target energy mix, this should be entirely achievable. However, PGE can go further and faster. Poland has multiple electricity generation alternatives. These include domestic onshore and offshore wind in and bordering the Baltic Sea; solar power

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[2] Ministry of State Assets. *Executive Summary of National Energy and Climate Plan 2021-2030*. December 30, 2019
[3] Ministry of State Assets. *Updated Draft Energy Policy of Poland until 2040*. August 11, 2019

nationally; smart grid options including demand-response and battery storage; and electricity imports from low-cost neighbouring countries.

In this report, we analyse the impact on PGE profitability of a low-carbon transition under three 2030 scenarios:

1. "Business as Usual (BAU)": This is PGE's expected energy mix through 2030, as published in its "PGE in Transition" updates

2. "NECP": This applies the government's NECP electricity mix in 2030 to PGE, as described in more detail in the following section

3. "Halving Coal": This goes further than the NECP, applying to PGE in 2030 the government's PEP40 goal to halve coal and lignite generating capacity by 2040

In this report, we do not consider nuclear power, given our 2030 horizon, and evidence that new-build nuclear construction in Europe presently exceeds 10 years from a final investment decision.[4]

We look at three scenarios: Business as Usual (BAU), the National Energy Climate Plan (NECP) and Halving Coal

Method

We calculated PGE's profitability according to three broad scenarios through 2030, as described briefly in the previous section.[5] For each scenario, we varied the installed capacity for coal, lignite, combined cycle gas turbines (CCGT), coal CHP, hydropower, onshore wind, offshore wind and solar, from 2020-2030. We made 2021 our base year, because of the introduction that year of the country's capacity market. The "hydro and other" category included hydropower, pumped storage and biomass. The CHP category included coal, gas and biomass CHP.

We applied our scenarios to PGE as follows. For the BAU scenario, we used PGE's present plans for installed capacity, as published in its regularly updated "PGE in transition" report. We then converted PGE's 2030 installed capacity into generation using capacity factors based on PEP40 data for average installed capacity and generation from 2020-2040.[6] We held this total generation figure constant across all three scenarios, so that PGE's market position in 2030 was unchanged. For the NECP scenario, we applied the national generation mix (in TWh) in 2030, as published in

[4] All three major new-build nuclear projects in Europe are based on EDF's European Pressurised Reactor (EPR) technology, and have exceeded or are expected to exceed 10 years' construction time (Flamanville, Hinkley Point C and Olkiluoto)

[5] For Poland's 2030 and 2040 goals, we used NECP and PEP40 data as reported by the government, and as published and compiled by the Polish thinktank Instrat: PEP40 in numbers

[6] We note that we used a previous version of PEP40, published in November 2018, to calculate capacity factors, because the newer version, published in December 2019, reported generation by fuel rather than technology, and so, for example, merged onshore and offshore wind.

the NECP, to our estimated PGE total generation in 2030.[7] We then converted this generation mix back into installed capacity using the same capacity factors as before. For the Halving Coal scenario, we took the same approach, this time using the PEP40 energy mix in 2040. For the NECP and Halving Coal scenarios, we brought back 2030 installed capacity mix by technology to 2020 in a straight line.

We resolved remaining energy mix issues in the following way. We did not account for nuclear power in our scenarios, because we do not envisage any nuclear power plants built within our 2030 time frame. For our PEP40 in 2030 scenario, we allocated any generation assigned by the PEP40 to nuclear in 2040 equally to onshore and offshore wind. We did not account for demand-side response and battery storage, because we allocated capacity according to generation, as described above, and neither of these technologies result in major net generation.

We used two key measures of profitability: earnings before interest tax and depreciation and amortisation (EBITDA), and net income. EBITDA measures earnings after accounting for short-term cash costs such as fuel and carbon. Net income includes a wider range of costs, including debt and tax payments, as well as depreciation, which expresses long-term investment in new equipment and capacity.

We use a low- and high-carbon price outlook, rising to €30 and €40 in 2030

We used various assumptions to calculate the revenues and fixed and variable costs of these energy sources, and estimate their individual profitability, and the profitability of PGE's electricity business as a whole (see the Annex for detailed assumptions). In our assumptions, we attempted as far as possible to reflect real market and policy trends, and to make the analysis less static. For example, we use forward markets for commodity prices (power, carbon coal and gas) in the near term, and thereafter, apply PGE's reference rate of inflation. Regarding carbon prices, we add further granularity with a low and high-carbon price outlook, rising to €30 and €40 respectively in 2030. In the case of the low-carbon price outlook, we take carbon prices at the end of the present forward curve in 2023 (€25.8 at the time of writing), and increase this by PGE's reference inflation rate (2.5%), leading to a €30 carbon price in 2030. For the high-carbon price outlook, our carbon prices jump from €25.8 in 2023 to €34.5 in 2024, and then rise by the same inflation rate to €40 in 2030. We focus on PGE's sensitivity to carbon price increases in this way because the amount of fossil-fuel generating assets is one of the key differences between the PGE present strategy scenario and our alternative scenarios.

Regarding other granularity, we varied the capital cost of new-build generation according to International Energy Agency technology-specific inflation assumptions. We used PGE's actual capacity market contracts to date, to estimate annual capacity

[7] To try and use the newer PEP40 as much as possible, we used generation capacities published in the new PEP40, and converted these into generation TWh, using capacity factors calculated from the previous PEP40.

payments to thermal generation. And we added an estimate for the cost for coal, CHP and lignite generation to meet tougher air quality standards, as expected under a new round of best available technology (BAT) conclusions, in the second half of the 2020s.

However, ours is not an hourly despatch model. We do not account for the impact of the cost of electricity generation on despatch to the grid. Instead, we use fixed capacity factors, based on the government's PEP40. And we do not account for dynamic interactions between commodity prices, for example between carbon and power prices, instead effectively locking-in the current cross-commodity price relationships. The only exception is our high carbon price outlook, where carbon prices jump in 2024. We note that reality could unfold in a far more negative way for fossil fuel investments. In particular, wholesale power prices may rise slower than carbon prices. Indeed, power prices may even fall as carbon prices rise, if imports of zero marginal cost renewables rise, and after taking account of the impact of Poland's capacity market. In this event, lignite generation especially may suffer more than as assumed in our model: carbon costs would rise, electricity sales fall, while lignite generation's fixed costs would remain the same.

We note that we conducted a "hindcast" of our model's ability to predict PGE's actual results in 2018. This hindcast indicated that the model produced a reasonably close forecast of our main metrics: generation; revenues; and EBITDA.

Findings

Installed Capacity and Investment by Scenario

Under our BAU scenario, PGE's coal and lignite capacity is unchanged from 2021-2030, while wind and solar capacity grows more than five-fold, to 5.7 GW (but still make up less than a quarter of total installed capacity in 2030). PGE invests some PLN 32 billion in renewables and PLN 16 billion in fossil generation. We note that all renewables capex is in growth, to build new wind and solar farms, and will generate new cash flows. By contrast, about a fifth of fossil fuel capex is in modernisation upgrades to meet stricter pollution standards, which at best maintain cash flows.

Under our NECP scenario, PGE's combined coal and lignite capacity falls by 17%, while combined wind and solar capacity grow to more than 10 GW. PGE invests PLN 63 billion in renewables, and PLN 8 billion in fossil fuels.

Under our Halving Coal scenario, PGE's combined coal and lignite capacity more than halves, while combined wind and solar capacity grows to nearly 22 GW. PGE invests PLN 129 billion in renewables. The latter is a large figure, indicating that this may be a more illustrative scenario.

Profitability: Low-Carbon Price Outlook

Under our low-carbon price outlook (€30 in 2030), coal and lignite EBITDA fall from 2021-2030. Coal EBITDA is barely above zero after 2025, while coal net income turns negative from 2029, because of the impact of air quality upgrades on depreciation. Investment in renewables drives almost all of PGE's growth in earnings. We summarise our findings as follows:

- In our BAU scenario, investments in renewables drive 22% growth in total EBITDA, despite falling coal and lignite earnings, but total net income falls by 12%. Net debt divided by EBITDA (a core ratio) rises to 2.0 times in 2030, from 0.5 in 2021, as a result of rising indebtedness to finance new renewables and conventional capacity, and conventional air quality upgrades.

- In the NECP scenario, much higher investment in more profitable renewables drives 47% growth in total EBITDA, while net income is barely changed. Net debt to EBITDA rises to 2.7 times in 2030.

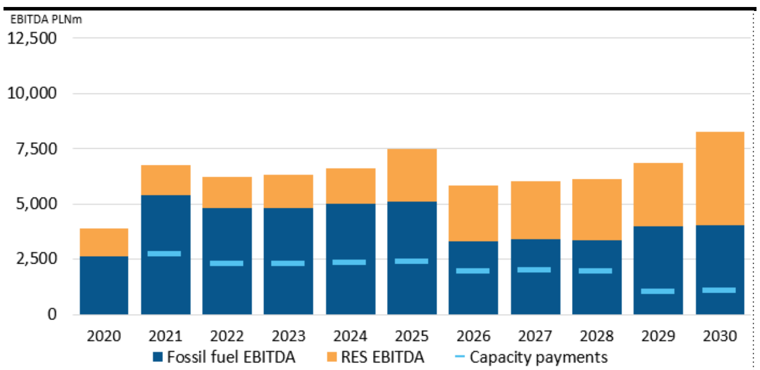
- In the Halving Coal scenario, EBITDA nearly doubles, and net income rises 21%. Net debt to EBITDA rises to 3.3 times in 2030.

Figure 1 illustrates these results for the renewables and fossil fuel businesses as a whole, for the first two scenarios. Renewables comprise hydro, onshore and offshore wind and solar PV. Fossil fuels comprise lignite, coal, CCGT and CHP. The light blue lines in Figure 1 show the level of annual capacity payments we expect the fossil fuel business to receive. These capacity payments fall after 2025, when coal and lignite are no longer eligible for new capacity market contracts, but still earn payments under legacy multi-annual contracts. The jump in fossil fuel profitability in 2021 is entirely due to the launch of Poland's capacity market that year. For this reason, all our comparisons are for the period 2021-2030, i.e. excluding the year 2020.

Figure 1 shows how renewables drive EBITDA growth through 2030. Fossil fuel earnings fall over time, as a result of gradually rising carbon prices; falling capacity payments; and (from 2026-2028) investment in air pollution upgrades.

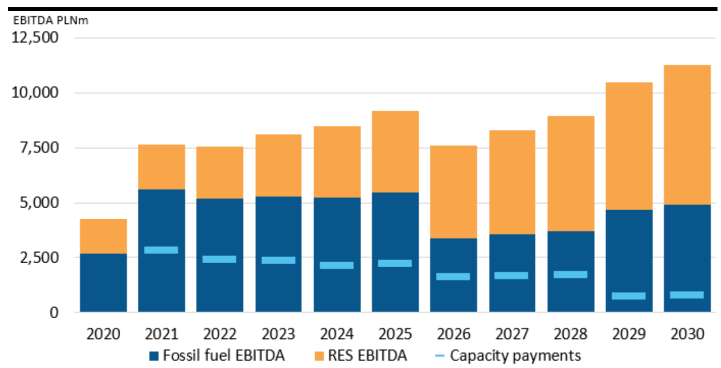
Figure 1. Low-Carbon Price Outlook: EBITDA of Renewables ("RES") vs Fossil Fuels, 2020-2030

BAU



Source: IEEFA

NECP

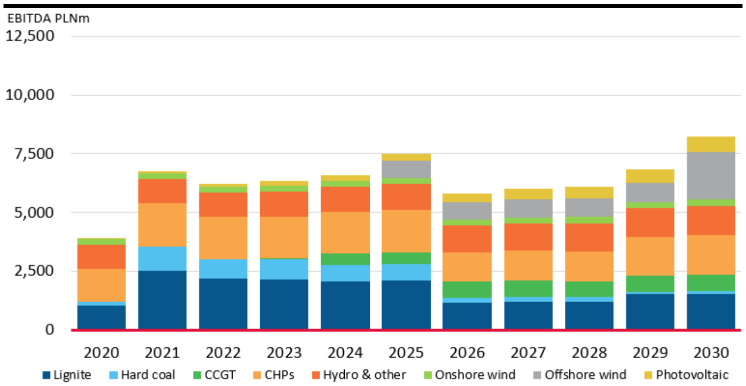


Source: IEEFA

Figure 2 shows the same findings as in Figure 1, but by more detailed business segment. Figure 2 shows how poorly coal and lignite perform, within the fossil fuel segment. Coal has near-zero EBITDA after 2025. Lignite accounts for more than half of power generation today, but only accounts for a small fraction of EBITDA after 2025. Figure 2 shows why PGE must start transitioning out of fossil fuels today.

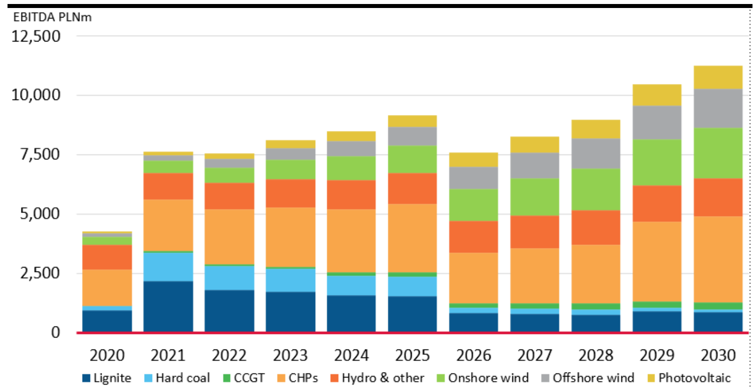
Figure 2. Low-Carbon Price Outlook: EBITDA of Wind, Hydro Solar, Coal, Lignite, Gas and CHP, 2020-2030

BAU



Source: IEEFA

NECP



Source: IEEFA

Profitability: High-Carbon Price Outlook

Our higher carbon price outlook (€40 in 2030) is within analyst forecasts.[8] The carbon price rises from the forward curve in 2020-2023, to €34.5 in 2024, and €40 in 2030. This outlook highlights the risks to PGE's present strategy. Both coal and lignite now have negative EBITDA and net income after 2025, despite the allocation of massive capacity payments to these businesses. We summarise our findings as follows:

- In our BAU scenario, poor coal and lignite performance now drag down the entire generation business: total EBITDA falls 29% and net income by 68%, from 2021-2030. Lower EBITDA undermines the core net debt/EBITDA ratio, which now rises to 3.5 times in 2030, from 0.5 times in 2021.

- In the NECP scenario, greater investment in renewables supports PGE's total EBITDA (up 5%). Total net income almost halves. Net debt to EBITDA is 4.4 times in 2030.

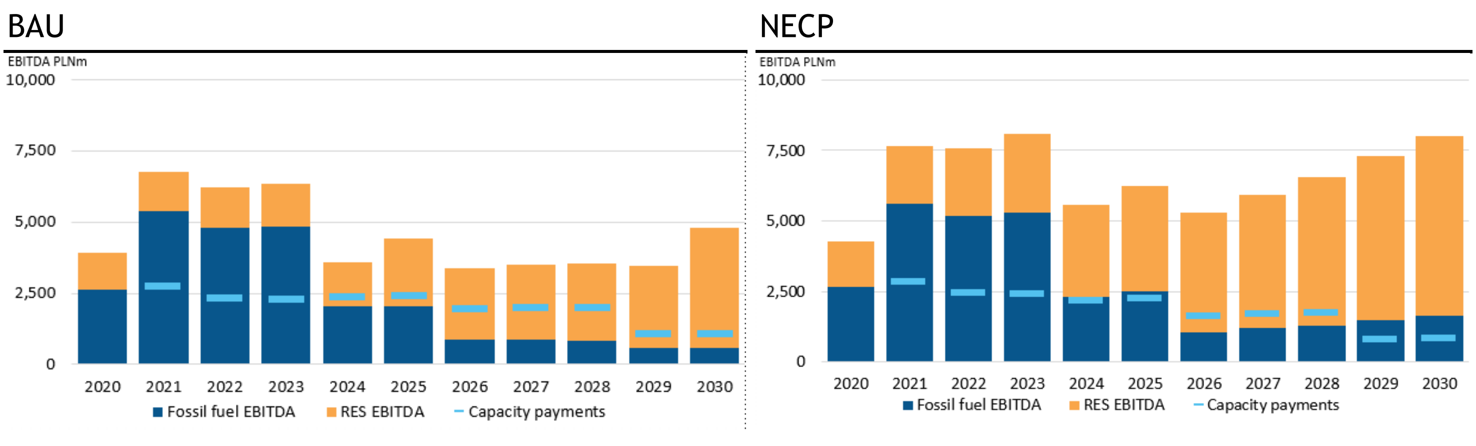
- In the Halving Coal scenario, total EBITDA rises nearly 70%, and total net income falls 12%. Net debt to EBITDA is 4.7 times in 2030.

[8] Reuters. Analysts cut carbon price forecasts as Brexit clouds market: Reuters poll. October 4, 2019.

Figure 3 provides more detail, and corresponds to Figure 1, except now for a high-carbon price outlook. We can see how PGE's entire fossil fuel business, which includes CHP and gas CCGT as well as coal and lignite, is now barely profitable in 2030. Almost all profit is now driven by the renewables business. Under the BAU scenario (left chart), cash flows from renewables investments are not enough to counter losses in the fossil fuel business, and overall EBITDA falls from 2021-2030. Under the more ambitious NECP scenario (right chart), the greater investment in renewables is enough to drive growth. Figure 3 underscores why PGE must start its low-carbon transition more urgently than under its present plans.

The red lines in Figure 3 show that in a high carbon price outlook, and under the BAU scenario (left chart), capacity payments are equal to or greater than the entire fossil fuel business EBITDA from 2024. In other words, without these subsidies the entire fossil fuel business, including CHP and CCGT, would be loss-making.

Figure 3. High-Carbon Price Outlook: EBITDA of Renewables ("RES") vs Fossil Fuels, 2020-2030



Source: IEEFA
NOTE: HC stands for High Carbon price sensitivity

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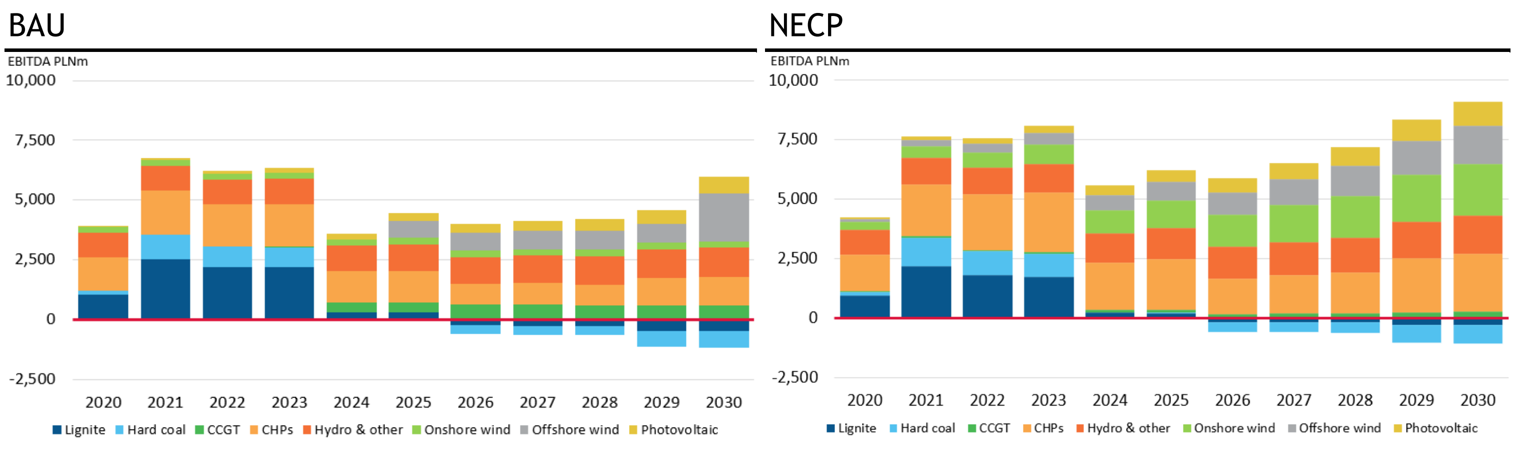
NOTE: HC stands for High Carbon price sensitivity

Figure 4 shows the same findings as in Figure 3, but by more detailed business segment. Figure 4 shows how coal and lignite are now on average both loss-making from 2026, underscoring the need to find new, more profitable sources of electricity generation urgently in the near term.

Figure 4. High-Carbon Price Outlook: EBITDA of Wind, Hydro Solar, Coal, Lignite, Gas and CHP, 2020-2030



Source: IEEFA
NOTE: HC stands for High Carbon price sensitivity

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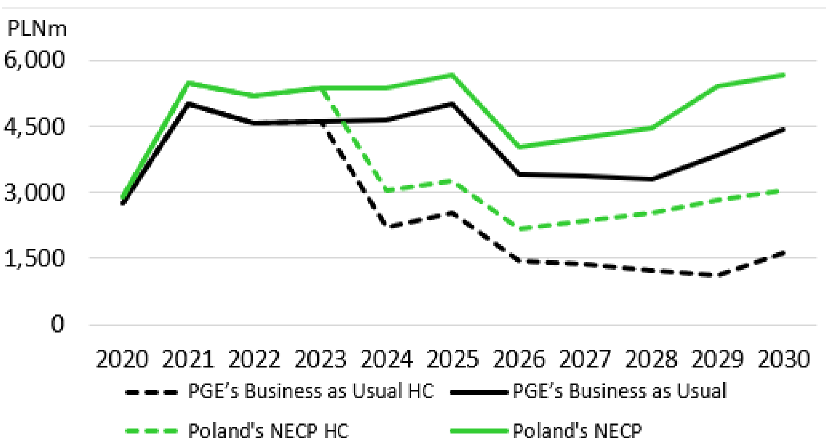
NOTE: HC stands for High Carbon price sensitivity

So far, we have discussed only the impact of different scenarios and carbon price outlooks on EBITDA. In Figure 5, we consider the impact on total net income. The black and green lines refer to the BAU and NECP scenarios respectively. The dotted lines show the impact of the higher carbon price outlook. The green dotted line in Figure 5 shows how the NECP scenario is more resilient to higher carbon prices.

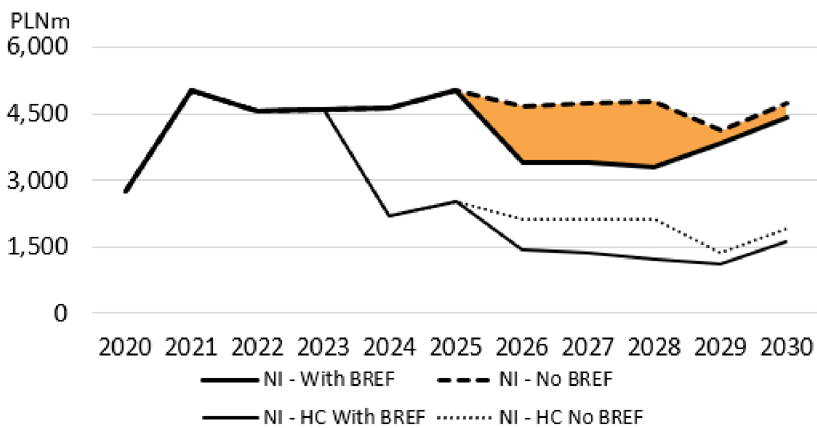
Figure 5. The Impact of Higher Carbon Prices on Net Income: BAU vs NECP



Source: IEEFA
NOTE: HC stands for High Carbon price sensitivity

Figure 6 below shows the impact of tougher air pollution emissions regulation, which we assume impacts coal, lignite and CHP from 2026 to 2028. Here we focus solely on the BAU scenario, corresponding to the black lines in Figure 5. In Figure 6, we show how removing the requirement for pollution upgrades (known as "BREF") – the dotted line – boosts net income. We assume that complying with BREF forces both additional capex investments and maintenance downtime (see Annex for detailed assumptions). Without BREF, the company's net income would be about 25% higher (the area highlighted in orange). Under the higher carbon price outlook, the impact of BREF is even higher in percent terms, given that BREF capex and the related reduction in plant availability would impact an already lower net income because of higher carbon prices. We discuss the impact of regulatory and related risk on the BAU scenario in more detail in the next section.

Figure 6. The Impact of Future BREF Regulation on Net Income for BAU Scenario (under lower and higher carbon prices)



Source: IEEFA
NOTE: HC stands for High Carbon price sensitivity

PGE and Asymmetric Risk

The risk of doing business is usually defined as a set of situations and conditions that could cause a company to be either more or less profitable than expected, depending on how future uncertainty is resolved. For example, inflation could be higher or lower; demand for power, or commodity prices could be higher or lower. We note that risk exposure is not the same thing as risk. For example, a company can have a high degree of risk because it has a large exposure to a small risk or has a small exposure to a large risk. PGE's overall risk depends on both its risk exposures and the magnitude of the underlying risks. This is true under all scenarios examined.

In this section, we discuss how our BAU scenario has more "asymmetric risk" than the other two. Asymmetric risk only goes in one direction. If we imagine flipping a coin, then it amounts to, heads nothing changes, tails you lose. Clearly, commodity prices are not asymmetric: prices can go up or down, and both directions will have an impact on coal, either negative or positive. However, the BAU scenario is more exposed than the other two to asymmetric, regulatory and environment-related risks.[9]

Let us consider some examples. In the case of air pollution regulation, no change in air pollution regulation has no impact on coal. However, new regulation can have a disastrous impact on the cost of power generation from burning coal, by inflicting new compliance costs, for example to install equipment which reduces air pollutant emissions. There will be either "normal" profitability for PGE if there are no further rounds of regulation which specifically impact fossil fuel generation, or "worse than expected" profitability if there are further rounds of regulation. A second example is increasing difficulty of access to external financing for fossil fuel-related projects, as a result of new, anti-coal policies by lenders including multilateral development banks. Either the cost of financing will remain the same for PGE ("normal" profitability), where there is no new anti-coal finance policy, or it will increase (yielding "worse than expected" profitability), in the event of such a policy.[10] A third example is tougher EU climate policy, perhaps expressed as a mandated coal phaseout: no coal phaseout is the status quo, and makes no difference. But an announcement of such a coal phaseout, as already made by many European countries, is potentially catastrophic for coal. One cannot exclude a coal phaseout for Poland.[11] In summary, the BAU scenario entails more asymmetric risk. Interestingly, the three examples above reflect potential outcomes that are not mutually exclusive: for example, PGE could well be facing stricter regulation and a more difficult financing environment.

Asymmetric risks are generally not reflected in cost of capital, even though they can be large and important

Unlike normal business risks, asymmetric risks are generally not reflected in conventional measurements of a utility's cost of capital, even though they can be large and important. Yet, such risks can impair PGE's opportunity to earn a fair return on the capital invested and – in extreme cases – could even undermine its financial integrity. Therefore, such regulatory risks should be measured and capital providers compensated for them. Alternatively, the risks must be otherwise mitigated, for example by buying insurance against such risks – either way costs to the firm are increased.

Because of asymmetric risks, there are three practical consequences for PGE under the BAU scenario. First, PGE's weighted average cost of capital (WACC) will be higher compared with the other two scenarios. Second, PGE may be forced to commit additional capital to "maintenance" capex – that is, capex that will not be

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[9] One such recent example is the case of coal-fired power plants in the Netherlands, where it was decided that modern, efficient coal-fired power plants would need to be closed in order for the country to meet its environmental objectives.
[10] There are multiple, recent examples of banks stopping any fossil fuel-related lending/financing. The probability that this trend reverses, or even stops, is extremely unlikely.
[11] In this case, the probability that such events happen is extremely low, but costs would be disproportionately high and potentially disastrous for the company.

"growth" creating, but merely used to keep up – and thus somewhat impair PGE's ability to increase its returns. Third, if the company does not protect itself from, or at the very least mitigate such risks, the danger is that a decrease of investor confidence has the ability to erode further the company's financial flexibility and its ability to raise additional equity capital. It is beyond the scope of this note to estimate the costs to PGE of such risk exposures and events. Furthermore, such differences tend to impact the company in net present value terms and the horizon we have chosen for our analysis is only ten years long. Nevertheless, the value of PGE as an enterprise will be impacted negatively. All in all, we conclude that under the BAU scenario, regulatory, one-sided, asymmetric risks, involving only downside potential could seriously impair PGE's financial health. PGE would be largely insulated against this under our alternative scenarios.

Annex - Assumptions

Commodity Prices

- We do not account for PGE's present hedging of commodity prices. We consider this a reasonable assumption, given our 2030 horizon. Neither do we account for any free allocation of EU allowances (EUAs), which we consider reasonable, given that PGE's free allocation has fallen rapidly and will largely expire, with the exception of free allocation for heating sources. We note that after taking account of carbon hedges and free allocation, PGE's effective carbon cost in 2018 was below €6 per tonne of CO2 emissions, compared with a spot EUA price at the time of writing of €25. PGE's increasing exposure to the latter market price over the next year or two, as its hedges expire and free allocation falls, will have a big impact on coal profitability.

- We use forward market curves as of January 16, 2020 to determine near-term values for ARA coal, Polish power, Polish natural gas and EUAs. Beyond these forward curves, we assume these commodities escalate at 2.5% annually, in line with PGE's reference annual inflation rate. The exception is for carbon prices, where we have an additional, higher carbon price outlook, where the carbon price jumps to €34.5 per tonne in 2024, and then rises with inflation to €40 in 2030.

- We do not dynamically account for interactions between different commodities, such as the impact of higher carbon prices on power prices.

- Regarding heat prices, we take PGE's actual sale price for heat from burning coal in 2018 of PLN 41.89/GJ, and inflate this by PGE's reference annual inflation rate (2.5%) through 2030.

- The foreign exchange rate we used for USD and euro conversion to Polish zloty (PLN) for commodity prices is the spot rate as of January 16, 2020.

Operational Assumptions

Electricity Generation:
We discount all gross thermal generating capacity by 15%, to take account of conversion to net generation and availability.

We used capacity factors based on generation and capacity data published in the Polish government's previous PEP40 strategy document, published in November 2018, because the more recent PEP40, published in December 2019, reported generation by fuel rather than technology. We used this approach with two exceptions. For offshore wind, we used actual capacity factors in the Baltic Sea as published by the operator EnBW. In the case of solar PV, we used capacity factor data for Poland published in the World Bank's Global Solar Atlas.

We may over-estimate hydropower generation, by assuming that all hydropower is used to generate power, rather than for pumped storage. We take this approach because the PEP40 does not distinguish between pumped storage and hydropower.

To account for wear and tear, we apply a 0.25% per year degradation factor to all electricity generation and heat production across all technologies.

In the case of thermal generation, we estimate average efficiency and carbon intensity by technology for coal, lignite and CHP, using published data for PGE's generation fleet today, including the newest units. Regarding CCGT, we use PEP40 assumptions. We assume that efficiency and carbon intensity remain the same through 2030. We therefore do not account for CHP conversion from coal to gas or biomass, because of inadequate PGE published data for these plans.

Heat Production:
PGE have published detailed data for actual heat production, power generation and installed electrical and thermal capacity for every coal and lignite power plant and CHP unit in 2017. We use these data to generate factors enabling us to convert any given installed electrical capacity to estimated heat production.

Financial Assumptions

Costs:
We use fixed and variable operating and maintenance (O&M) costs by technology as reported in the Polish government's PEP40, and published by Instrat.

We also use capital expenditure (capex) of new-build energy technologies as published in the PEP40, with the exception of lignite, hard coal and solar PV. In the case of lignite and hard coal, we used PGE data for the actual capex of brand new units at Turow and Opole. For solar, we used recent news reporting of actual capex at a new Polish solar project. For capex inflation through 2030, we used data published in the IEA's World Energy Outlook 2019.

Regarding the regular cycle of required best available technology (BAT) air pollution upgrades (known as "BREF"), we expect that the next programme will have a compliance deadline of 2028. We assumed a compliance cost for thermal generation (coal, lignite and CHP) of PLN 0.25 million per megawatt of non-compliant capacity, based on PGE's reported compliance cost of PLN 2 billion in the latest round of BAT upgrades. We assume that upgrades will be needed across 70% of PGE's capacity, and that upgrade work will require the closure of non-compliant capacity for 12 months, spread over three years from 2026-2028. These assumptions lead to an estimated BAT compliance capex of PLN 3.1 billion under the BAU scenario, falling to PLN 1.6 billion under the Halving Coal scenario.

We assume a depreciation period of 25 years for new-build capex, and 10 years for BREF upgrades. We use a corporate tax rate of 19%.

Debt:
We assume all capex is phased over four years. We assume that 45% of this phased capex is debt-financed, at an interest rate of 5%, and the balance is paid from annual cash flows. We assume all borrowing is on balance sheet rather than project finance.

We allocate PGE's total outstanding debt at the end of 2018, of PLN 10.7 billion, to the company's individual business segments (generation, supply and distribution) pro rata according to their share of EBITDA at the end of 2018, at roughly 55%, 5% and 40% respectively. In this way, we allocate some PLN 5,900 million debt to the generation business (conventional and renewables) in 2020.

For simplicity, we attribute debt interest payments to individual energy sources (coal, lignite, CHP, gas and renewables) according to their share of capex in that year. This approach somewhat disfavours renewables initially, since almost all the initial debt was used to finance coal and lignite, but we allocate to renewables as the main engines of capex going forward.

We allow some limited repayment of debt, from annual cash flows, at 12.5% of annual outstanding debt from 2021-2028.

Revenues:
We focus exclusively on PGE's generation business, excluding its supply and distribution businesses. Within the generation business, we focus exclusively on heat and electricity sales. We therefore exclude sale of origin rights and ancillary services and distribution services.

We do not account for any subsidies: all electricity sales including renewables are at wholesale market rates. The only exception is capacity market payments for thermal generation.

We calculated success rates for capacity market bids by energy source (coal and lignite versus gas), using published capacity market data. We then applied these success rates to the installed capacity of our four fuel sources (lignite, coal, CCGT and CHP), in each of our PGE scenarios. For CHP, we used the success rate as calculated for coal.

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About the Authors

Gerard Wynn

Gerard Wynn is an energy finance consultant at IEEFA, specialising in the economics and finance of renewables and fossil fuel generation. He has previously worked as an analyst, editor and writer, in the energy and environment sectors. He worked for a decade as a reporter and columnist at Reuters News Agency, covering energy and climate change. He started his career with a PhD in agricultural economics.

Paolo Coghe

Paolo Coghe is an international financial economist with over 20 years of experience focused on energy markets and commodities research, analysis and strategy. Before founding energy consultancy Acousmatics, he held positions with the Brattle Group, Centrica, Koch Supply and Trading, and Societe Generale. He has conducted research on European energy markets for publication by IEEFA since 2016. Paolo holds degrees in Business Economics from the McCallum Graduate School of Business at Bentley University, and in Economics from the University of Cagliari.

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