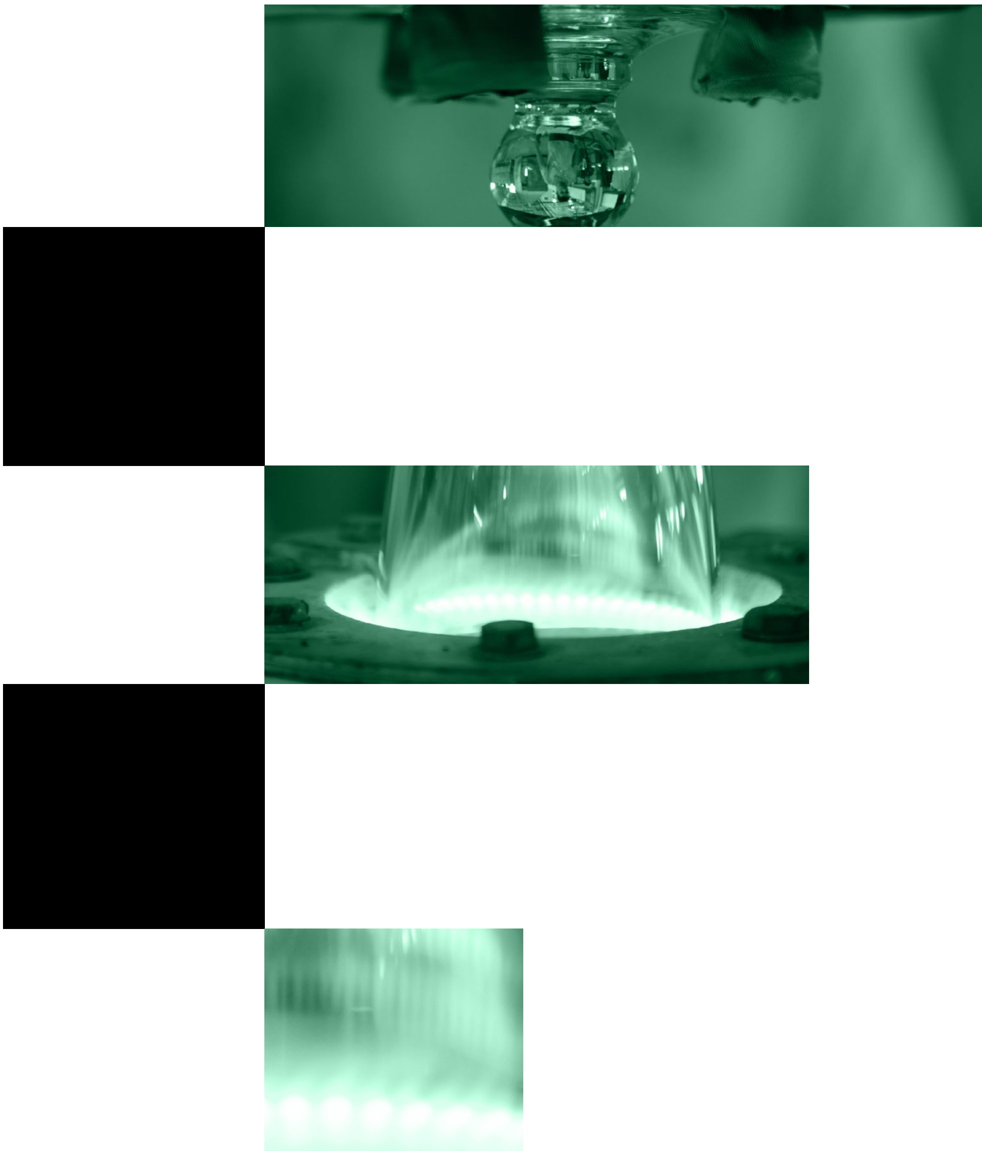
REPORT

Energising industry #2: Financial aspects of industrial heat electrification in Poland

Klaudia Janik, Bernard Swoczyna

Warsaw 2025



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REFORM

The Reform Institute is an independent think tank dedicated to the continuous improvement of public policies in Poland, Europe and the world. One of the Institute's key areas of activity is support for the energy transition and climate protection.

Abstract

Poland's industry faces a number of challenges, including the need to remain competitive with non-EU competitors at ever-increasing labor and energy costs. Decarbonization of the economy is necessary to offset the cost advantage of countries with their own fossil fuels.

The European Union's long-term strategy is to achieve climate neutrality by 2050. The energy carriers commonly used by industry, particularly natural gas and hard coal, will be phased out due to the burden of increasing costs of their use on producers and the parallel promotion of production using zero-carbon sources (e.g. through green public procurement).

Currently, it is more profitable to use natural gas and forest biomass for industrial heat production. However, this will soon change.

In 2027, the ETS2 will come into force, raising the price of fossil fuels in industrial installations not yet covered by the Emission Trading Scheme (EU ETS). At the same time, growing demand for biomass is already resulting in restrictions on the energy use of high-value forest biomass. Further restrictions and growing demand after the introduction of the ETS2 mean fierce competition for available biomass between industry, district heating and households for individual heating. Nuclear (SMR) and carbon capture (CCS/CCU) technologies can help the largest plants in energy-intensive industries but are not suitable for smaller industries. In contrast, cogeneration using natural gas is a tricky solution that may pay off temporarily, especially with current support instruments, but does not eliminate industrial plants' dependence on increasingly expensive natural gas.

For most plants that don't have significant primary energy sources of their own (such as biogas or waste biomass), the only viable path is to switch to primarily renewable electricity. This is quite a challenge, especially for heat, which tends to be less cost-effective to electrify and decarbonize than other energy uses.

The biggest barrier to industrial electrification today is cost. Heat production from electricity is usually more expensive than from gas. Due to high operating costs, there is a risk that electrification will remain a niche for the years to come, and lack of experience will slow its implementation once it finally becomes profitable.

We are threatened by the "gas trap", i.e. dependence on the second (after coal) phased-out fuel, this time almost entirely imported. If this happens, Polish industry will lose the competitive battle with EU companies using cheaper, local renewable energy and will get bogged down in a technology with no future for a dozen years. Therefore, support for electrification is needed now to build competence among both domestic technology consumers and domestic supply chains.

An electricity system with a large share of RES is characterized by large fluctuations in energy prices, which creates both risks and opportunities. It can be profitable to build one's own sources, but it can also be profitable to take advantage of price differences – buying energy at a low price during hours of high RES generation and selling or reducing

consumption at other times. Switching to a single primary energy carrier also allows for waste heat recovery with heat pumps.

With the ongoing decarbonization of the national electric power system, it is the electrified heat sources that will become cost-competitive. Assuming the development of energy carrier prices in accordance with the draft National Energy and Climate Plan (aKPEiK), electrification using industrial heat pumps will become cheaper than coal and gas after 2035. In turn, electrification of processes requiring medium and low temperatures can be cost-competitive with a gas boiler as early as the 2020s-30s (depending on the process and temperature required). Industry should consider such a horizon when making investment decisions.

Companies can use commercial financing, their own funds and EU grants. There are also forms of support for operating costs, i.e. CHP premium. However, such support discourages consumption flexibility and slows down the energy transition. It is necessary to redesign the tools that support solutions such as heat pumps and electric boilers to make it worthwhile to replace fossil fuels with renewable energy, primarily electricity.

Our analysis shows that investment support alone is not enough to prepare Polish industry for the coming changes. Poland should immediately implement instructions to support companies in covering operating costs after electrification. In addition to changes in the structure of tariffs and the capacity market fee, sliding feed-in-premiums for industrial heat could be such an incentive. In parallel, work is needed on energy market reform, as well as accelerating the expansion of RES and grid infrastructure so as to improve the systemic cost-effectiveness of electrification.

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Glossary of terms

BGK	National Development Bank
CAPEX	Capital Expenditures
CCS/CCU	Carbon Capture and Storage/Carbon Capture and Utilization. Capture of carbon dioxide emitted by industrial installations for subsequent use or injection underground
CfDs	Contracts for Difference; a contract for difference is a contract that equalizes the cost of selling energy (including heat) to the generator up to a specified amount. If the selling price differs up or down from the specified amount, the difference is paid to or collected from the generator.
DSR	Demand Side Response; actions on the part of electricity consumers to support the operation of the electricity system, often for a fee, by increasing or decreasing at a signal the consumption of electricity
ESG	Environmental, Social and Governance; a company's environmental, corporate social responsibility and corporate governance activities
ETS2	The Emission Trading System 2; extension of the CO_2 trading scheme to small emission sources, the fee will in practice be added to the price of fuel
EU ETS	Emission Trading System, operating in the European Union, covering only large emission sources, e.g. boilers with thermal power above 20 MW.
FEnIKS	European Funds for Infrastructure, Climate, Environment 2021-2027
GJ	gigajoule (unit of energy)
GW	gigawatt (unit of power)
KPEiK	National Energy and Climate Plan
KPO	National Plan for Rebuilding and Increasing Resilience
ktoe	kilotonne of oil equivalent; (unit of energy)
LCOH	llevelized cost of heat, taking into account both current generation costs, such as fuel purchases, and amor – tization of capital expenditures
MW	megawatt (unit of power)
MWe	megawatt (unit of power) relative to electricity
MWh	megawatt hour (unit of energy)
MŚP	small and medium-sized enterprises
NFOŚiGW	National Fund for Environmental Protection and Water Management
OPEX	Operational Expenditures
PPA	Power Purchase Agreement; PPA is a long-term contract for the supply of electricity, usually between an electricity generator and an electricity consumer.
PSE	Polskie Sieci Elektroenergetyczne S.A. (Polish transmission system operator)
SMR	Small Modular Reactor; a small modular nuclear reactor
URE	Energy Regulatory Office
WAM	With Additional Measures; one of the future scenarios prepared as part of the NECP

1. Main benefits of industrial electrification

1.1. Competitiveness and safety

European dimension – the EU can be a leader in clean technologies

Decarbonisation of industry based on innovative technologies is a key element of the European Union's strategy to strengthen the competitiveness of the economy. Achieving climate neutrality by 2050 requires emissions reductions in all sectors, including industrial production. It is therefore essential to switch production processes to low-carbon technologies and renewable sources.

Europe, while still having a substantial research and development base and an extensive base of companies supplying machinery and industrial installations, has the opportunity to build a leading position in the production of "clean technologies" for manufacturing companies. This will make it possible not only to reduce dependence on imported raw materials and increase energy security, but also to develop new industries and create jobs.

Technologies at an early stage of development or commercialization, such as high-temperature heat pumps and electrode boilers, have particularly high potential. However, the development of these solutions will not be possible without stimulating demand from industrial consumers.

Polish dimension – electrification as an opportunity for the economy

Polish industry's dependence on fossil fuels is making it increasingly difficult to supply the international market with high-quality products with the characteristics desired by customers, among which the product's carbon footprint plays an increasingly important role[1]. At the same time, political and military risks are growing in importance. A centralized energy system is extremely vulnerable to military attacks. In contrast, supplying industry with energy from distributed and fossil fuel-independent sources increases the infrastructure's resilience to crises, as well as maintaining strategic production capacity despite rising political tensions.

Polish economy therefore has much to gain from industrial electrification – both economically and in terms of energy security.

1.2. Benefits for the industry

Preparation for ETS2

Smaller industries (i.e. installations below 20 MW) will start paying for CO_2 emissions from 2027. That's when the ETS2 system will start, in which the cost of emissions will be added to the price of the fuel (as an indirect charge). This means that in the coming decade the cost of energy from fossil fuels will increase significantly for smaller manufacturing companies. Industry can prepare for this scenario by implementing mature and scalable electrification solutions that are already available.

1 Poland is the country with the second highest (after Estonia) electricity emissivity in the European Union, expressed in grams of CO_2eq/kWh, according to 2023 data. It lowers competitiveness of Polish products, export opportunities and the willingness of foreign investors to locate their operations in the country.

Electrification as a long-term strategy

The operating costs of electric-powered heating in factories are high today. However, with the ongoing decarbonisation of the national electricity system, electrified heat sources that will become ever more cost-competitive. According to the transition model included in the draft National Energy and Climate Plan (aKPEiK), electrification using industrial heat pumps will become cheaper than coal and gas by 2035-2040 (we write more about this in Section 2.1).

Electrification also brings tangible energy efficiency benefits – reduced energy consumption (due to avoided losses in the conversion of chemical to thermal energy), the possibility of using waste heat, and reduced cooling costs.

In the meantime – new electricity purchasing models

Businesses can already proactively manage their energy costs – changing vendors, using day/night or dynamic tariffs. Larger customers can also buy electricity at wholesale prices in the day-ahead or intraday market, as well as enter into bilateral contracts with clean energy producers under a PPA[2] (Power Purchase Agreement). The latter are gaining popularity, especially among multinational enterprises looking to optimize costs and meet ESG reporting requirements (e.g., by demonstrating production of goods using renewable energy). Smaller companies count on either favourable market conditions or government intervention.

2 This is a contract between a customer and an electricity generator, in which the price of energy is predetermined for a longer period.

Flexibility as a source of revenue

The electricity market is characterized by high volatility. There are fluctuations in both prices, demand for electricity, and the level of green energy production. Such dynamics create space for industry to cooperate with the electricity system.

Electrified industry, which can temporarily reduce energy consumption (e.g., on certain days or hours), has an opportunity for additional revenues. The provision of flexibility services to the system is done within the framework of the power market or Demand Side Response (DSR) service – we write more about this below.

Flexibility can be provided, among other things, by plants where energy-intensive processes – such as product annealing – are cyclical and can be rescheduled to specific hours of the day. It is more difficult to achieve such flexibility in companies with continuous production, which requires a stable heat production profile.

More versatile solutions to increase industry flexibility in energy management include electricity storage, heat storage, and diversification of supply, for example, through production from the company's own power source as a supplement to grid power.

Selected ways to monetize flexibility

- **DSR**

Since 2018, large industrial plants have been able to participate in the power market by providing a power demand reduction service (they are paid for their willingness to curtail consumption at the operator's request)[3]. Auction experience shows strong interest from industry – for the 2026 and 2027 delivery years, 1.5 GW each of this service has been contracted, for 2028 and 2029 about 1 GW each[4]. The greater the degree of plant electrification, the greater the potential to earn money from this source.

- **Balancing market**

After the reform of the balancing market in 2024, companies can participate in balancing the electricity system on similar terms as power plants. Thus, they can contract the services of increasing energy consumption for a short period of time or giving it to the network, receiving additional compensation for this. While current earnings from this are not yet

3 The last auctions under the functioning power market (with delivery until 2040) will be held in December 2025. Discussions are underway about setting up a new support mechanism that will ensure continued financing of power in subsequent years.

4 See the chart illustrating these figures HERE on the Energy Forum website.

encouraging, this may change over time. The balancing market will be developed by Polskie Sieci Elektroenergetyczne (PSE) due to the growing need to ensure system stability.

Easier access to financing

Electrification supports a company's preparedness for ESG reporting, which facilitates access to sustainable financing. An increasing number of capital groups are integrating climate risks into their business strategies to increase resilience to the resulting risks. Companies investing in electrification can continue to operate within global value chains and benefit from preferential bank financing for their investments.

Simpler, standardized operations

In addition to economic benefits, electrification means optimization of operational and maintenance processes. Electricity is already present in all industrial plants. Its wider use would allow standardization of health, safety and fire procedures, simplification of logistics and greater automation of plant maintenance. The knowledge and competence gained by staff through electrification of process heat can be used in other sectors, for example, through the exchange of experience between electricians in different departments of the same company.

2. Electrification costs under the magnifying glass – cost-effectiveness analysis

2.1. The foundation of electrification: heat pumps as primary heat sources

Operating costs key to investment decisions

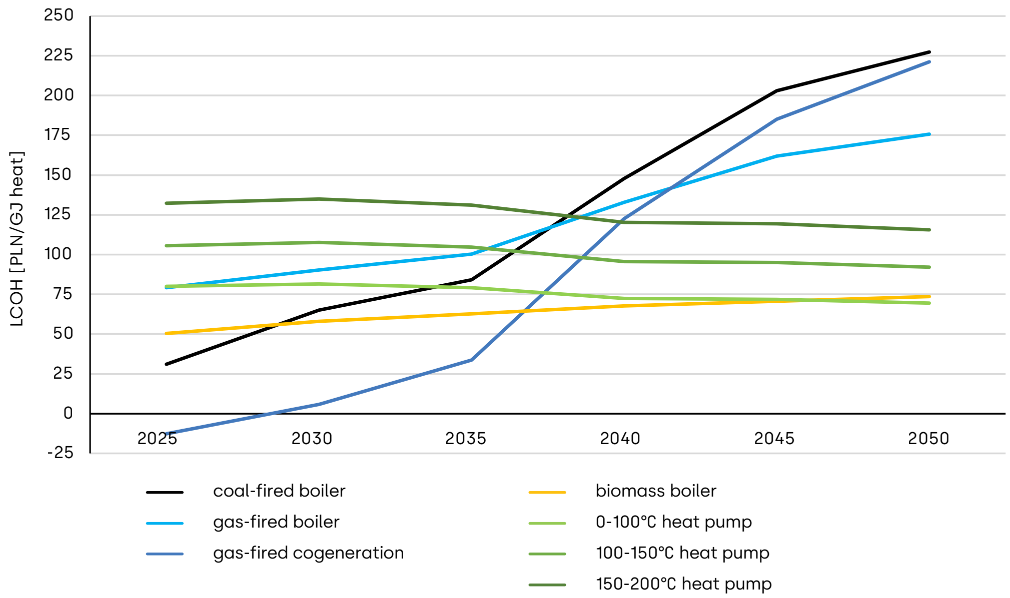
For many companies, energy costs are one of the main operating expenses. Therefore, industrial plants look at the average cost of heat (LCOH), which depends most heavily on the prices of energy carriers and the cost of CO_2, before making investment decisions.

Investment costs associated with electrification remain a significant barrier for many industrial plants (due to limited access to equity capital and administrative difficulties in obtaining support). However, it is the operating costs – i.e., current expenses for heat generation – that have a decisive impact on the choice of electrification technology.

Fossil fuels cheaper, but only temporarily

Currently, the cost of producing heat from electrified sources is higher than for fossil fuel-based technologies such as coal-fired boilers or gas cogeneration. Exceptions are situations where heat pumps can be used efficiently.

Figure 1. Unit cost of heat generation (LCOH) for various installations, 2025-2050.



Source: own study by the Reform Institute

The temporarily lower cost of producing heat from fossil fuels may lead some pre-businesses to invest in gas-based technologies, such as gas-fired cogeneration. In the long term, however, this may prove to be a trap. First, fossil gas will be a transitional fuel, even if the transition period is extended due to necessary investments in new gas capacity because of the phase out of coal-fired power plants. Second, once the ETS2 (and other policies related to the EU's gas phase-out) come into effect, the cost of using this fuel in industry will increase significantly. Third, renewable gases (biomethane and hydrogen from renewable energy), which are partly expected to replace fossil gas, will be primarily used for "special tasks" – dedicated uses mainly in energy-intensive industries where there is no other option for decarbonisation (see Figure 6 for detailed assumptions on the use of these gases). This is due to very high production and transport costs, independent of the scale of production. **As a result, between 2035 and 2040, the cost of heat from industrial heat pumps, even at relatively high temperatures (for heat pumps), will equal or become lower than the cost of heat from gas.**

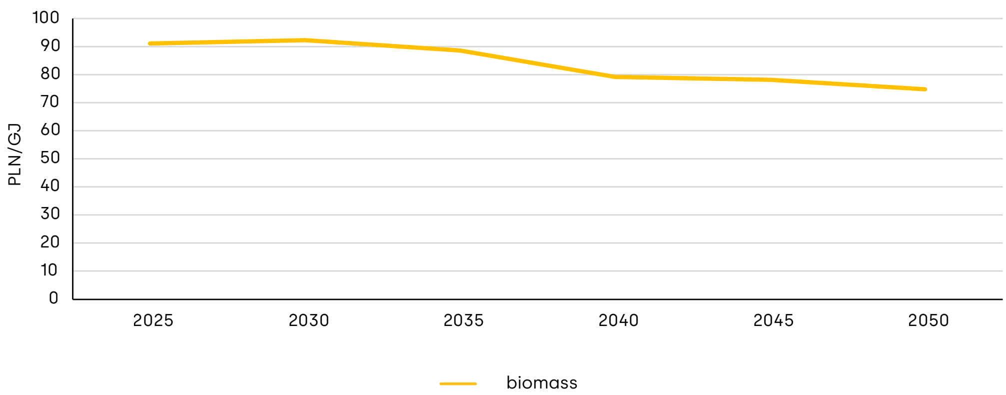
Beware of the biomass trap

Analysing current biomass prices and the forecast shown in Figure 1, it seems that this fuel represents an attractive pathway for industry decarbonisation. However, it is worth remembering that biomass is a significantly limited resource. Increased demand – with insufficient domestic supply – could lead to a sharp increase in the price of a resource that meets the criteria for sustainable harvesting.

An additional risk is regulatory uncertainty. As the EU approaches its 2050 climate neutrality target, negative emissions mechanisms will become increasingly important. One can therefore expect the development of new CO_2 capture technologies and the introduction of pricing mechanisms and/or standards that will also cover actual CO_2 emissions from biomass combustion. This means that biomass – today considered "zero-carbon" – will be burdened with additional costs in the future.

In the chart below, we show at what borderline price biomass combustion ceases to be cost-effective compared to direct electrification with heat pumps.

Figure 2. Biomass price at which heat from high-temperature heat pumps is cheaper than from a biomass boiler, 2025-2050

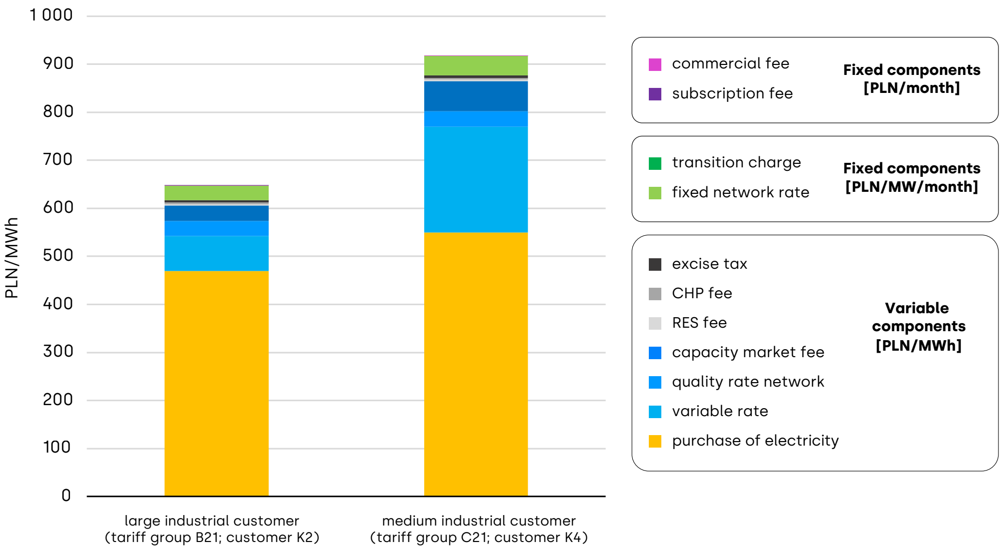


Source: own study by the Reform Institute

Disproportionate burden on electricity

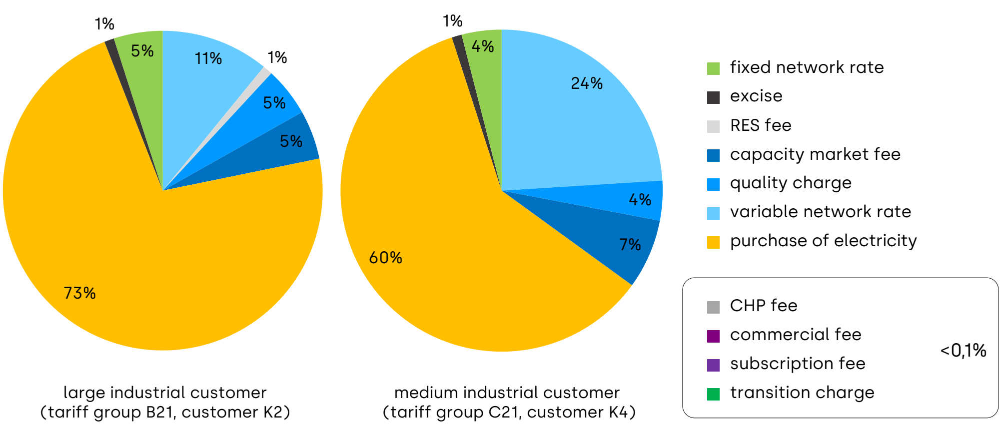
The high price of electricity is due, among other things, to the fact that a system dominated by fossil fuels is the one that sets marginal prices in the merit order mechanism. At the same time, the electricity sector has been covered by the EU ETS since 2005, and the direct burning of fuels– outside of the largest industrial installations – has so far remained outside the emissions trading system. As a result, electricity price, despite the fact that this energy carrier increasingly comes from clean sources, is systemically linked to emission fees and coal and gas prices. This gives rise to a paradox, since installations that directly burn emission fuels do not bear such burdens today. In addition, the energy bill includes additional charges for, among other things, maintaining power plant dispatchable capacity, support for cogeneration and renewable energy, as well as costs related to grid infrastructure. As we show below, for a medium-sized industrial customer, fees can account for as much as 40% of the bill. The European Commission points to the unequal charging of electricity and fossil fuels in its recent recommendations under the European Semester for Poland as a barrier that needs to be removed to lower energy bills[5].

Figure 3. Components of the electricity bill of industrial consumers in Poland in 2025[6]



Source: Reform Institute's own study

Figure 4. Percentages of bill components for industrial enterprises



Source: own study by the Reform Institute

Meanwhile, the use of fossil fuels involves virtually no additional payments – other than the relatively low cost of transporting and distributing the raw material and excise taxes.

In addition, their mining and burning is still subsidized by the state, both overtly (e.g., compensation for losses due to price freezes during the energy crisis, direct subsidies for

5 See the Commission's recommendations to Poland dated June 4, 2025 HERE.

6 Types of customers for the purpose of calculating the capacity market fee:

- final customer K2 – customer with small variability of consumption profile (not less than 5% and less than 10% during peak hours, compared to other hours of the day), for which the correction factor for the power charge is 50%,
- end customer K4 – customer with a high consumption profile variability (not less than 15%), for which the coefficient correcting factor for the capacity market fee is 100%.

Tariff groups for the purpose of calculating the network fee structure:

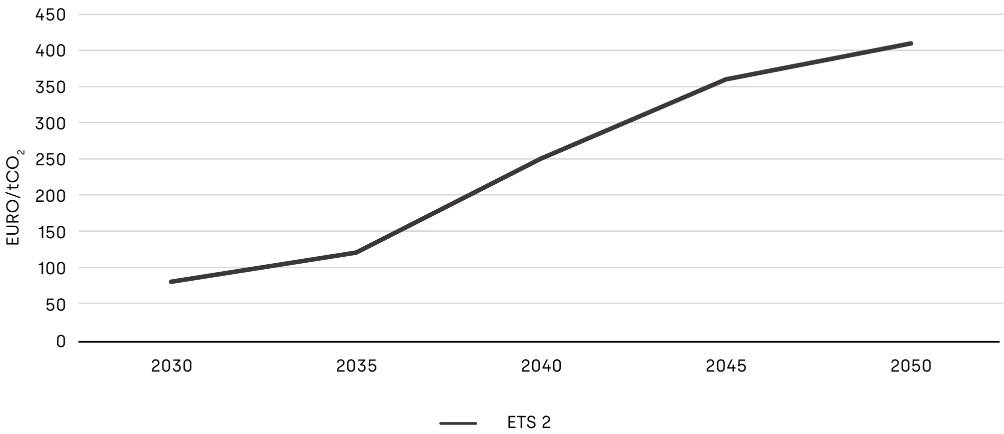
- tariff group B21 – single-zone for customers supplied from the medium-voltage grid, whose contracted power exceeds 40 kW,
- tariff group C21 – single-zone tariff group for customers supplied from low-voltage grid, whose contractual power exceeds 40 kW.

coal mining) and covertly (e.g., forgiveness of mining damage fees, mining pension subsidies, treasury guarantees for the sector). This burdens taxpayers, including businesses.

Rising emission costs will increase the profitability of electrification

Long-term emission price projections for the ETS2 show a dynamic **increase between 2035 and 2040 – from about 125 to 250 euros per ton of CO_2**. This trend is expected to continue in subsequent years.

Figure 5. Price assumptions for the price of CO_2 allowances in ETS2



Source: Reform Institute assumptions based on Polish NECP projections.

In the table below, we show how the change in these proportions will affect the first year of profitability of heat pumps over fossil fuels.

Table 1. Year of achieving cost balance between heat from conventional sources and electrified heat

Year of achieving cost advantage	Coal boiler	Gas boiler	CHP
Heat pump 0-100°C	~2034 r.	~2026 r.	~2037 r.
Heat pump 100-150°C	~2036 r.	~2036 r.	~2039 r.
Heat pump 150-200°C	~2038 r.	~2038 r.	~2040 r.

Source: own study by the Reform Institute

The cost-effectiveness of electrification largely depends on the application and the required temperature. **For example, heat pumps will become cheaper to operate than gas boilers for low-temperature heat and heat up to 200°C[7] as early as 2026-2038.**

Electrification to be planned proactively

After 2035, heat from heat pumps will be cost-competitive with burning of both natural gas and coal. While this seems to be a distant prospect, investment decisions are worth considering now. Large industrial investment projects – due to administrative processes – take as long as 7-10 years. On top of that, electrification may require a change in the production process, which entails the cost of replacing machinery and rebuilding the plant. It's a complicated undertaking that usually involves downtime.

It is also important what condition the sources operating at the plant are in. Frequently profitable investments are postponed because the depreciation period of old equipment

7 We define low-temperature heat as the heat to be provided at temperatures up to 100°C. We define medium-temperature heat as heat with a higher temperature, but not exceeding 400°C. High-temperature heat is defined as heat with a temperature exceeding 400°C.

has not yet passed. By planning investments well in advance, such "sunken costs traps" can be avoided.

In order not to fall behind and to remain competitive, the industry should start preparing for deep electrification now.

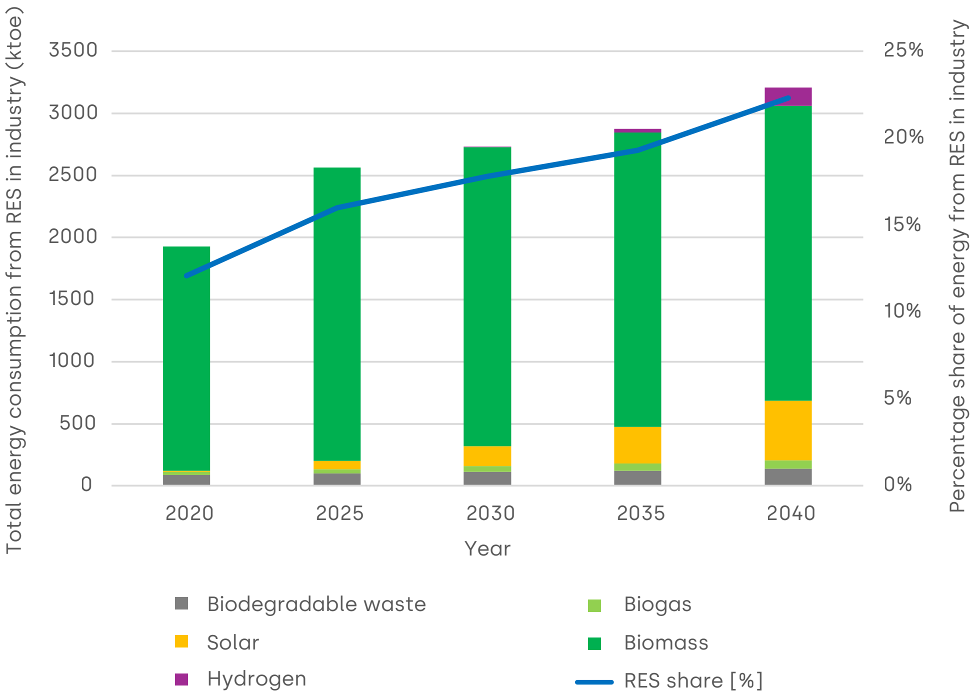
Gas cogeneration could still be important, but in a new role

Gas cogeneration will play an important role in the transformation and electrification of industry in Poland. During the transition period, it can be part of hybrid systems in which it will boost the temperature at the outlet of the heat pump to a higher value (e.g., in sectors needing medium-temperature heat).

Increasingly, high-efficiency natural gas-fired cogeneration engines will also serve as sources that provide flexibility services to the electricity system. For example, they may provide heating instead of heat pumps during DSR services.

In the 2050 horizon, natural gas may be gradually replaced by biogas, increasing the share of RES in the energy mix[8]. The table below shows possible scenarios for such a change.

Figure 6. RES energy use in industry [ktoe] according to the WAM scenario constituting Appendix 1 to the Polish NECP as released for consultation on November 15, 2024[9]



Ineffective support for CHP hinders energy transition

The current support system for industrial cogeneration – the so-called cogeneration bonus – hinders electrification and flexible management of heat production. Industrial cogeneration plants receive a high subsidy for each megawatt hour of electricity produced. In 2025, the reference price in auctions for small CHP units (1-50 MWe) is 248.81 PLN/MWh[10].

The premium is highest with a constant electricity production profile. Therefore, it is not profitable for such units to adapt to changing market conditions, e.g. to use periodic surplus energy from photovoltaic farms to convert them to heat, which could have both environmental and electric grid-related benefits.

8 Polish NECP does not assume the use of biomethane in industry, the assumption is self-consumption by producers.

9 The document is available HERE. Table 1.29 was used.

10 The announcement of the URE regarding the second 2025 auction for the CHP PREMIUM.

2.2. Flexible support: electrode boilers

Electrode boilers – appropriate tariff structure increases cost-effectiveness

The wholesale electricity market is characterized by high volatility. The growing share of photovoltaics[11] translates into pronounced price fluctuations throughout the day. Negative energy prices in the day-ahead market have been emerging since 2024. Such conditions create space for the use of cheap energy during hours of RES oversupply by electrode boilers acting as peak sources.

11 Reaching more than half of Poland's electricity demand during the sunniest hours of the year, primarily in the spring and summer months.

The profitability of using an electrode boiler as a peaking source is mainly influenced by the appropriate tariff structure (see Figure 3), in particular:

- the structure of the variable network rate component;
- the structure of the fixed network rate component;
- the fee for the capacity market mechanism.

In the following section, we analyse the impact of these elements on the cost-effectiveness of a hybrid system that consists of a cogeneration engine for the baseload and an electrode boiler as the peaking heat source. Details of the boundary condition assumptions for such a hybrid system are presented in the Appendix.

Dynamisation of the variable component of the grid rate

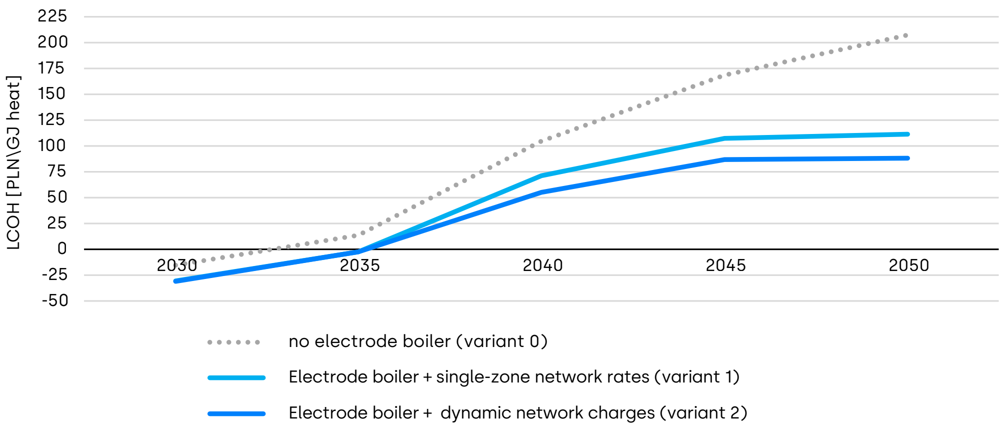
The variable component of the network rate is a component of the charge for transmission and distribution of electricity. It depends on the amount of electricity consumed [PLN/kWh] and is calculated based on:

- variable costs of energy transmission and distribution (cost of covering transmission losses);
- the portion of fixed costs not included in the fixed component.

The following shows how the dynamisation of the variable component of the network rate (variant 2), i.e. the transition from a fixed price of PLN/kWh to a price depending on the situation in the system[12], affects the profitability of the operation of the hybrid system.

12 You can read more about dynamic grid charges in this REPORT by the Reform Institute.

Figure 7. Graph of the time course of the unit cost of heat generation in a hybrid system with different variants of the structure of the variable component of the network rate.

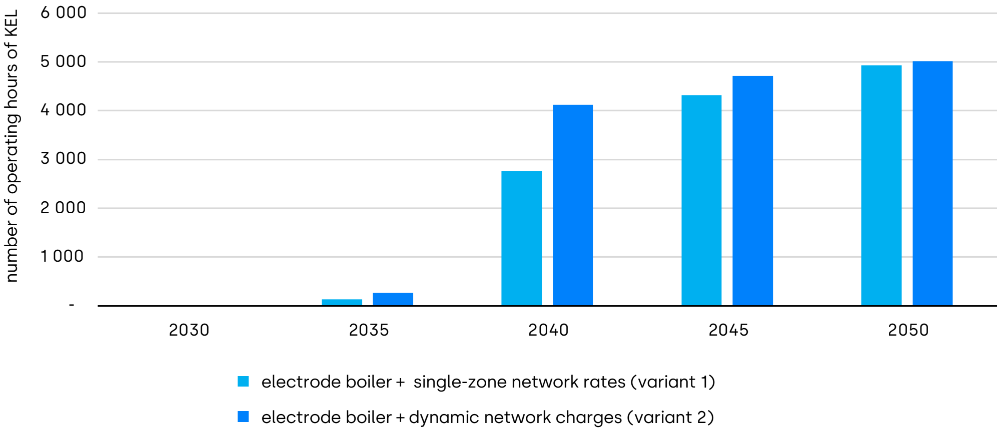


Source: own study by the Reform Institute

In such a model, after 2035, the cost of heat production from the hybrid system (CHP and electrode boiler) becomes lower than the cost of operating the CHP engine alone.

Additional savings occur due to the dynamic structure of the variable rate. This means that **the dynamisation of the variable component of the grid rate can positively affect the cost balance of operation of the hybrid system.**

Figure 8. Electrode boiler operating time per year in hours with a correspondingly low electricity price under different variants of the structure of the variable component of the grid rate



Source: own study by the Reform Institute

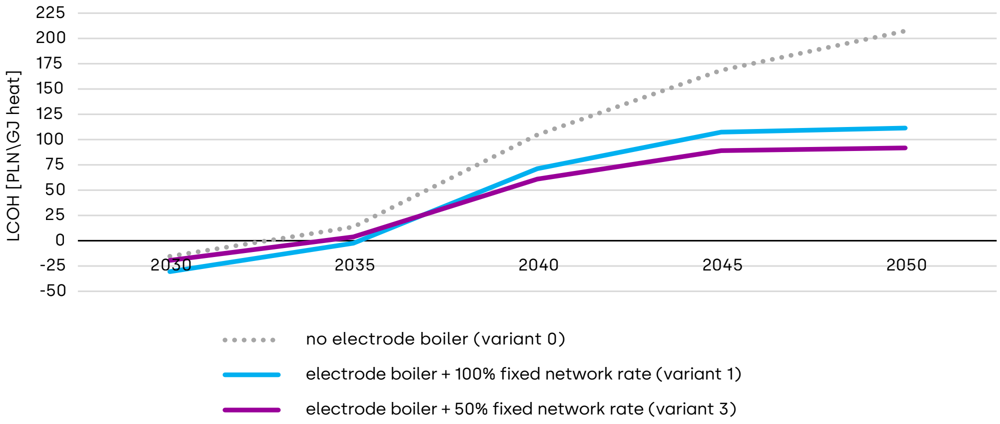
However, even this solution is not enough to make the investment in an electrode boiler as a peaking source profitable before 2035. Only then does the boiler begin to support cogeneration for about 200 hours per year, which changes the economics of such an investment. In 2040, the number of these hours increases to about 3,000 hours/year for the variant with a single-zone grid rate and 4,000 hours/year for the variant with dynamic grid charges. This means that **the investment in an electrode boiler operating as a peak source begins to be profitable only in the 2035-2040 perspective.**

Lower fixed component of the grid rate

Investors indicate that a barrier to investment in a peaking electrode boiler is the increase in costs associated with the fee of the fixed component of the network rate. The amount of this fee for industrial customers depends on the level of ordered power, which increases when the boiler is connected to the grid.

Simulations show that a 50% reduction in the amount of the fixed network rate would favourably affect the economic calculus of a hybrid system with an electrode boiler.

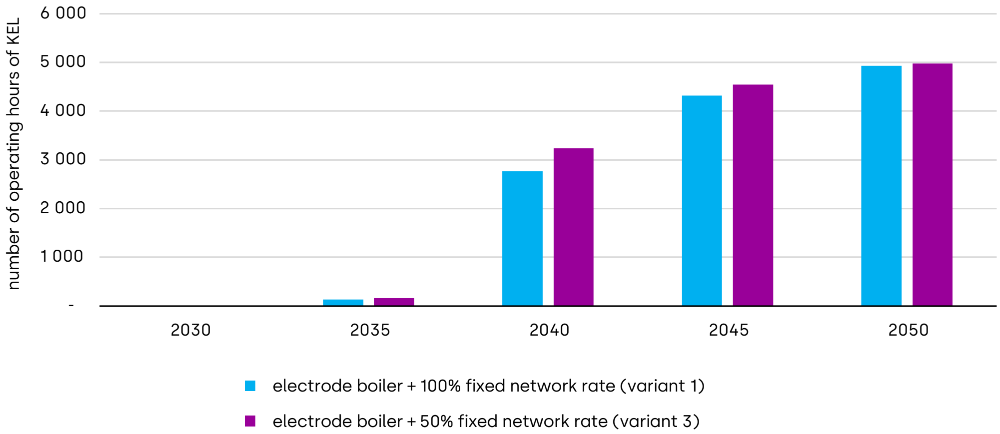
Figure 9. Graph of the time course of the unit cost of heat generation in a hybrid system with different variants of the structure of the fixed component of the network rate



Source: own study by the Reform Institute

Using only this solution would bring moderate benefits and not be enough to ensure the profitability of investments before 2035.

Figure 10. Electrode boiler operating time per year in hours with correspondingly low electricity price under different variants of the structure of the fixed component of the grid rate



Source: own study by the Reform Institute

The operation of the electrode boiler as a peak source, with a reduction in the fixed component of the network rate, begins to be profitable in the period 2035-2040.

Impact of the capacity market fee on the profitability of electrode boilers

The fee for the capacity market mechanism is a significant barrier to the development of systems using electric boilers. This mechanism penalizes hybrid solutions that periodically use electric heat sources, rewarding a constant electricity consumption profile.

Capacity market fee and flexibility of demand in industry – what is the problem?

The capacity market fee is a component of the electricity bill, introduced with the creation of the capacity market in 2018. It finances a support mechanism for dispatchable generating capacity necessary to ensure the security of energy supply for which PSE (Polish TSO) is responsible.

The height of the capacity market fee is determined by the President of the URE. An important element of this calculation for large consumers is the so-called correction factor. It is intended to reward consumers with a stable consumption profile throughout the time and penalize those consumers who significantly increase their consumption during peak demand hours, as defined by the URE – currently between 7 am and 9 pm[13]. The capacity market fee is charged for each MWh of energy consumed during these hours on working days. The amount of the fee depends on the consumption profile and can be 17%, 50%, 83% and 100% of the rate set by the URE president for a given year[14]. The lowest level applies to customers whose average consumption during the daytime peak hours is at most 5% higher than during the other hours of the day (i.e. 24:00-7:00; 21:00-24:00).

Starting in January 2025, a new method of measuring consumption was adopted. Instead of averaging data over an entire month (used in 2021-2022) or over ten consecutive days of the month (as in 2023-2024), the coefficient is now calculated for each working day. This change makes the system more sensitive to short-term deviations. For installations using, for example, electrode boilers as a peak source, the new rules mean a clear deterioration in the profile, which translates into a higher capacity charge for each MWh of energy consumed. As a result, energy costs are rising, which could derail the viability of such a hybrid installation.

The way the aforementioned coefficient is calculated does not take into account weather conditions and the related situation in the system, e.g. surplus energy from RES that should be used. This makes the current mechanism penalize flexible consumers, i.e. those who adjust their energy consumption to the capabilities of the grid. Meanwhile, from the point of view of the system, they are the ones who are more desirable.

A similar mechanism for calculating the capacity market fee is to take effect for individual consumers starting in 2028 (currently the rate is flat)[15].

13 Peak demand hours for 2025 have been set by the URE at 7 a.m. to 9 p.m., on weekdays.

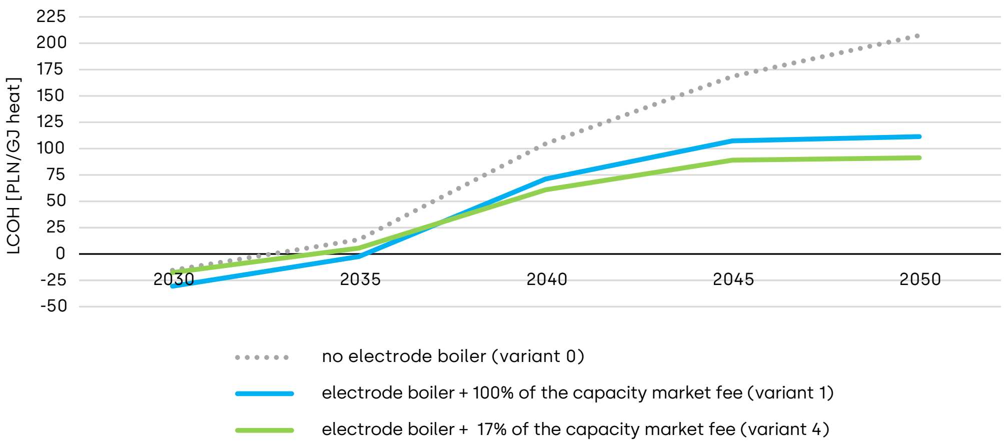
14 The rate for 2025 is 141.2 PLN/MW.

15 See the URE President's announcement on this topic HERE.

Simulations show that reducing the correction factor from 100% to 17% can improve the cost-effectiveness of a hybrid system.

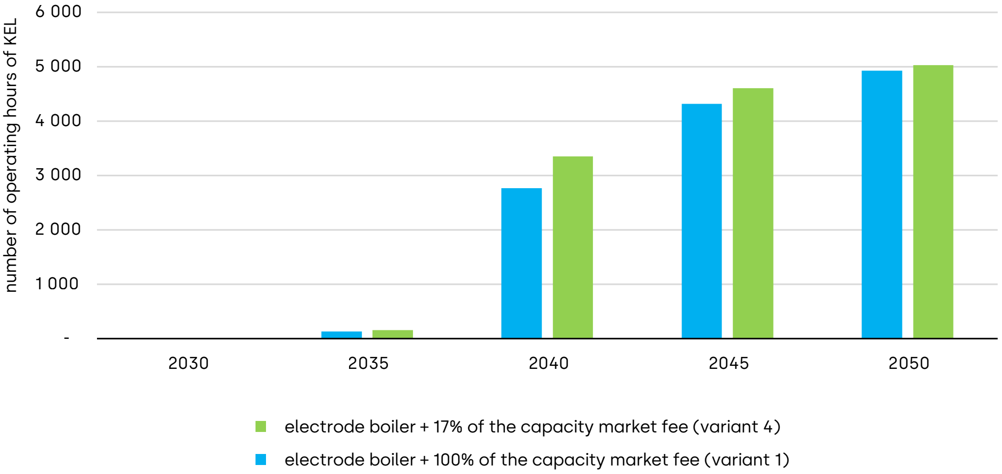
The analysis assumes that the cogeneration engine and electrode boiler function as a stand-alone system. That is, the potential effect of a change in the capacity market fee on electricity costs resulting from consumption by other equipment was not considered. The effect of the reduction will be greater the greater the share of other installations than the electrode boiler in the company's total electricity consumption. This means that the impact of the change in the correction factor for the power charge is most pronounced where electricity consumption (for machinery etc.) is dominant over heat consumption.

Figure 11. Graph of the unit cost of heat generation in a hybrid installation with different variants of the capacity market fee structure over time



Source: own study by the Reform Institute

Figure 12. Electrode boiler operating time per year in hours with a correspondingly low electricity price in different variants of the capacity market fee structure



Source: own study by the Reform Institute

Adjusting the capacity market fee mechanism alone – even in the direction of rewarding flexibility – would have a limited effect on the profitability of the hybrid system, comparable to the effect of reducing the amount of the fixed grid rate.

Systemic support for flexibility is not enough

As the analyses show, tariff changes such as dynamisation of network charges, reduction of the amount of the fixed network rate and adjustment of the correction factor for the capacity market charge have some positive effect on the cost-effectiveness of electrode boiler operation as a peaking source. Each of these mechanisms operates on a similar scale, but none of them significantly changes the profitability of industrial electrification over the next few years. The greatest impact on increasing the profitability of flexible use of the electrode boiler will come from changes in the amount and spread of electricity prices in the dynamic tariff and the rising cost of CO_2. These factors will translate into an increase in the cost of CHP engine operation.

In 2030-2035, electrode boiler operation will remain unprofitable, regardless of the mechanisms implemented to encourage flexible operation (see Figure 7, Figure 9, Figure 11). The main reason is the existing CHP bonus. It provides a large incentive for inflexible operation of the CHP engine as a baseload heat source.

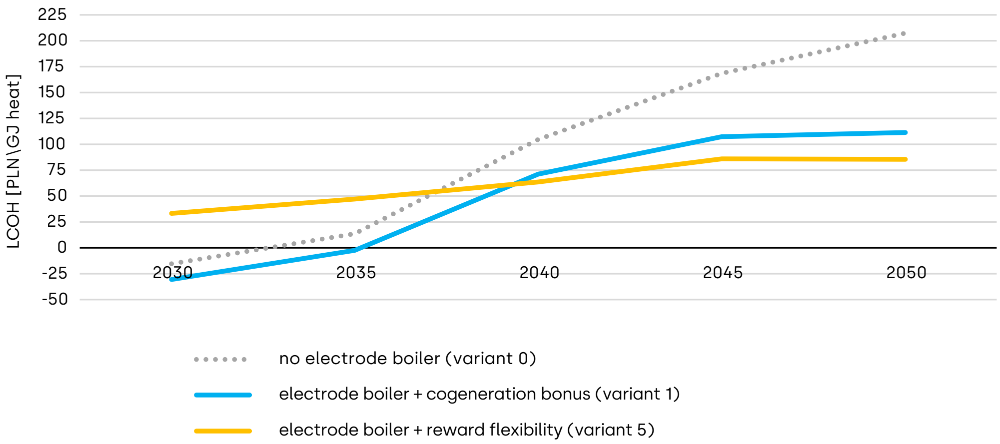
Scenario without CHP bonus – better profitability of flexible sources

Given the need to increase the flexibility of the electricity system, also with the support of industry, maintaining the CHP bonus in its current form (as operating costs support tied to the volume of electricity production) will be a suboptimal expenditure of public funds. It would be more efficient to start allocating these funds to mechanisms that reward labour flexibility.

It is worth noting that deep electrification of heat production based largely on renewable sources will not only reduce emissions and fossil fuel consumption,but also improve energy efficiency. Thus, one of the main goals of the introduction of the CHP premium – increasing the efficiency of the use of energy carriers – can now be more effectively achieved with other tools.

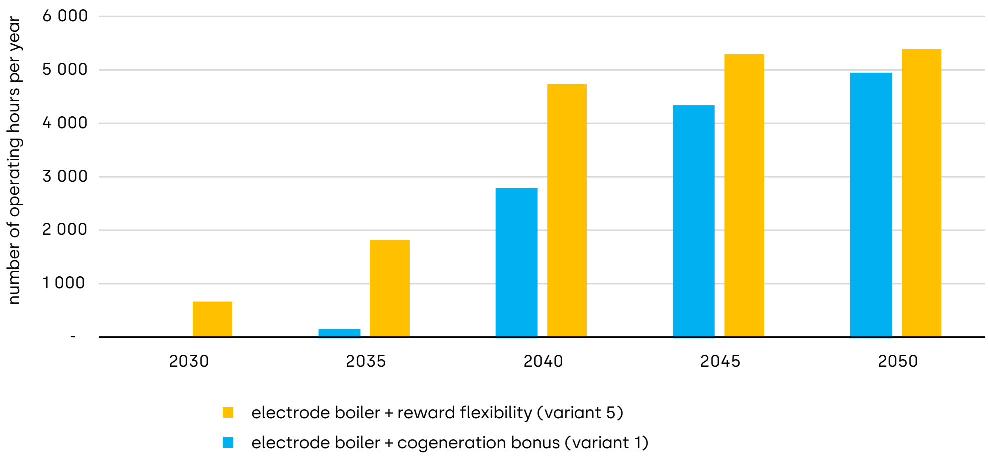
Below is a comparison of two scenarios. In the first, the engine operating in a hybrid system benefits from the CHP bonus. In the second scenario, the company is not entitled to the CHP bonus, but three changes are made to the tariff system to promote flexibility.

Figure 13. Graph of the time course of the unit cost of heat generation in a hybrid installation under different cost variants – CHP bonus vs. rewarding flexibility



Source: own study by the Reform Institute

Figure 14. Electrode boiler operating time with correspondingly low electricity price in different variants – cogeneration bonus vs. flexibility remuneration (hours per year)



Source: own study by the Reform Institute

In the second scenario – despite the lack of a CHP premium – it is possible to achieve cost-effective operation of the electrode boiler as early as 2030, with a production time of 1,000 hours per year.

The need for a comprehensive regulatory approach

The conclusions of the analysis are clear: none of the tariff mechanisms separately guarantees the profitability of industrial electrification. However, it is possible to implement a comprehensive regulatory solution that includes all of the above-mentioned elements: tariff changes, such as dynamisation of network charges, reduction of the amount of the fixed network rate, and adjustment of the correction factor for the capacity market fee. However, this requires a systemic approach on the part of legislators and the regulator to electrification and consideration of the benefits of removing the CHP premium for selected sectors. Such an approach will make it possible to achieve the economic benefits of electrification for medium – and low-temperature industries as early as the next five years. At the same time, all the changes under discussion mean better consideration of the cost drivers in the bills of energy consumers, giving them a stronger incentive to act in a cost-effective manner for the entire energy system.

3. Financial support instruments

To accelerate the electrification of industrial heat sources, investment support instruments are also needed. For companies planning to modernize or replace equipment, these will include grants and loans to cover investment costs (CAPEX).

For companies starting electrification of heat sources "from scratch", operational support mechanisms (OPEX) will also be unnecessary.

Below are the options available in Poland for subsidizing the electrification of industrial heat.

3.1. Investment support (CAPEX)

3.1.1. Public funds: grants and loans from the European Union budget

Poland is currently the beneficiary of four programs that allow investment in industrial decarbonisation. These are:

- **National Recovery and Resilience Plan (NRRP)**[16] The program's budget, including both grants and loans, is to be spent between February 1, 2020, and December 2026[17]. The goal is to rebuild the economy after a pandemic, with a focus on increasing resilience to future crises, including competitiveness and energy security. As the disbursement deadline approaches, state institutions are prioritizing it as a source of support. The program operates on the basis of a reform plan and milestones[18], on which disbursement of funds is conditional. It includes a "Green Energy and Energy Intensity Reduction" component to support the environmental and energy transformation of the national economy.
- **European Funds for Infrastructure, Climate and Environment (FEnIKS)**[19] is one of the largest national programs funded by the European Union's cohesion policy. It is intended for environmentally friendly development of the country through the construction of technical and social infrastructure. It offers mainly non-refundable grants, with a subsidy rate of 50% to 85%[20]. Among the objectives supported are energy efficiency, reduction of greenhouse gas emissions, and adaptation to climate change. FEnIKS subsidizes activities in small and medium-sized enterprises, local governments and households, among others.
- **The Modernization Fund**[21] is an additional source of funds available to 13 EU countries with lower per capita incomes. Poland is the largest beneficiary. The funds are managed by NFOŚiGW, and are not subject to typical funds programming. They are directed to priority programs designated by the NFOŚiGW covering, among other things, energy efficiency in industry. An important pillar of the Modernization Fund is investments in improving energy efficiency in energy-intensive industry in the form of a loan of up to 100% of eligible costs. The funds are to be spent by 2030, with absorption currently at 35%[22].
- The fourth major pool is the **Regional Priority Programs** for 2021-27, managed by the provincial authorities. Beneficiaries may include local governments and businesses. Funds can also be spent on investments in power generation[23].

16 PROGRAM WEBSITE

17 The extension of the program's end has been postponed by six months, relative to the original date (June 2026).

18 More on the POLISH PROGRAM WEBSITE.

19 INFORMATION PAGE ON GOVERNMENT WEBSITES

20 You can find the program rules HERE.

21 MODERNIZATION FUND INFORMATION PAGE

22 Own calculations, assumed EU ETS prices of 70 Eur/t CO_2.

23 INFORMATION PAGE ABOUT EUROPEAN FUNDS

Each of the four instruments makes it possible to reach support for CAPEX costs. The greatest spending pressure is on the NGEU, whose funds must be contracted by 2026. The FEnIKS program has a spending horizon until 2029, and the current pool of the Modernization Fund has a spending horizon until 2030. In the case of regional programs, the n+3 rule applies. This means that funds contracted until 2027 can be spent until 2030.

In addition, innovative projects in the area of energy efficiency (including battery and hydrogen technologies) can apply for support from the EU-wide Innovation Fund[24]. This fund is designed to support developing technologies at the stage between initial research and prototype (funded under Horizon Europe) and production deployment (supported by programs such as InvestEU). In 2025, the Fund plans to launch auctions providing remuneration for the decarbonisation of industrial process heat. According to the assumptions presented by the European Commission, the auctions will be conducted under a fixed-premium formula, where the commodity is a fixed subsidy in euros per unit of decarbonised heat generated (EUR/MWh) or euros per ton of reduced CO_2[25]. The planned amount of support is €1 million. The initiative is designed to promote innovative electrification technologies, renewable heat solutions and other decarbonisation strategies in various industry sectors. Auctions will be available to both smaller companies and mid-cap companies.

24 INFORMATION PAGE ON GOVERNMENT WEBSITES

25 See more in a discussion paper prepared by the European Commission HERE.

3.1.2. Public funds: loans and guarantees

Bank Gospodarstwa Krajowego (BGK) is the second – besides the NFOŚiGW – significant distributor of EU funds, including from the NGEU. For years it has specialized in providing preferential loans and subsidies to housing cooperatives and communities, mainly for the purpose of thermal modernization of buildings and/or installation of RES. BGK also offers support to businesses for energy efficiency improvements. However, the scale of subsidies is smaller, due to a lower budget. Like the NFOŚiGW, BGK also does not run programs aimed directly at industrial heat electrification.

3.1.3. Commercial loans

Many banks offer loans or other financial instruments to finance projects that contribute to decarbonisation. The terms and conditions of these loans, including interest rates and evaluation criteria, are determined individually by the banks with interested clients. The environmental effects of such investments are assessed in accordance with the EU Taxonomy for Sustainable Investment[26].

26 For an explanation of what a taxonomy is, see HERE

3.2. Lessons learned from the use of existing CAPEX support instruments to date

Programs financing industrial decarbonisation with public funds from the NFOŚiGWs offer have so far attracted limited interest. As a result, some of the funds originally earmarked for this purpose have been reallocated to other programs for different beneficiaries, including households. Among the reasons for the low utilization of funds by companies are:

- insufficient knowledge of available instruments and the benefits of decarbonisation (especially in the SME sector),
- concerns about application and settlement procedures (e.g., mandatory 30% increase in energy efficiency),
- reluctance to increase debt, even at preferential terms,
- difficulty in justifying the profitability of investments due to the higher operating costs of technologies such as heat electrification compared to fossil fuel alternatives.

Concerns about making commitments in the absence of a stable national energy policy and the aforementioned lack of profitability of electrification in the short term are also likely reasons.

Polish companies should actively take advantage of available funds, especially in the context of anticipated changes in the EU's approach to investment financing. In the new financial perspective, the pool of funds for decarbonisation may be smaller due to the redirection of part of the budget for defence and the need to repay the EU's joint debt. Brussels will also move away from non-refundable grants to loans. The opportunity to secure attractive grant financing may not be repeated after 2030.

We have no information on the popularity of commercial support instruments.

3.3. New strategies and instruments announced by the European Commission

As part of the European Commission's new mandate, it is expected to publish in the fourth quarter of 2025:

- Industrial Decarbonisation Accelerator Act;
- Recommendation on Energy Taxation.

Both documents are expected to identify measures to increase the cost-effectiveness of industrial decarbonisation, including electrification. A detailed **Electrification Action Plan**, which should suggest specific legislative solutions, is expected in the first quarter of 2026 (in parallel, a **Heating & Cooling Strategy** is being prepared, which will also address solutions for industrial heat electrification – it is up to the Commission's discretion to spread the industrial threads between the two documents).

The Commission also announced the creation of an **Industrial Decarbonisation Bank**[27], to support EU climate policies and stimulate the development of the clean technology market, including financing innovative industry.

In parallel, preparations are underway[28] for the programming of the next EU financial perspective (Multiannual Financial Framework 2028-2034). Within its framework, it is planned to launch the EU **Competitiveness Fund**, which will support, among other things, the clean tech sector and industrial decarbonization[29].

3.4. EU state aid rules and heat electrification

Member countries offering grants, loans or other forms of support to companies must comply with state aid rules designed to prevent distortions of competition in the EU market. These rules, compiled in several documents[30], in principle prohibit state funding of fossil-fuel-based sources, and specify the conditions for supporting companies without the need to notify the European Commission.

EU funds cannot be used to increase the production capacity of enterprises. However, it is permissible to support the modernization or change of production technology – including elements of the production line – provided that the current scale of production is maintained. In exceptional cases, it is possible to subsidize an investment involving the replacement of an entire installation or plant with another one operating in the country. This is possible when decarbonisation through changes to the installation or plant itself is not possible, and it is necessary to erect a new installation or plant. However, this must not, at the same time, violate intra-EU competition rules. This means that it is possible to replace one installation or plant with another on a 1:1 basis, without increasing production capacity. Then, this counts as a decarbonisation of production capacity in a country without an increase.

The provision of state aid outside this framework requires special approval from the European Commission. Otherwise, it is considered illegal.

27 THE ANNOUNCEMENT OF THE CREATION OF THE BANK

28 COMMUNICATION FROM THE EUROPEAN COMMISSION in response to a question about the competetiveness fund

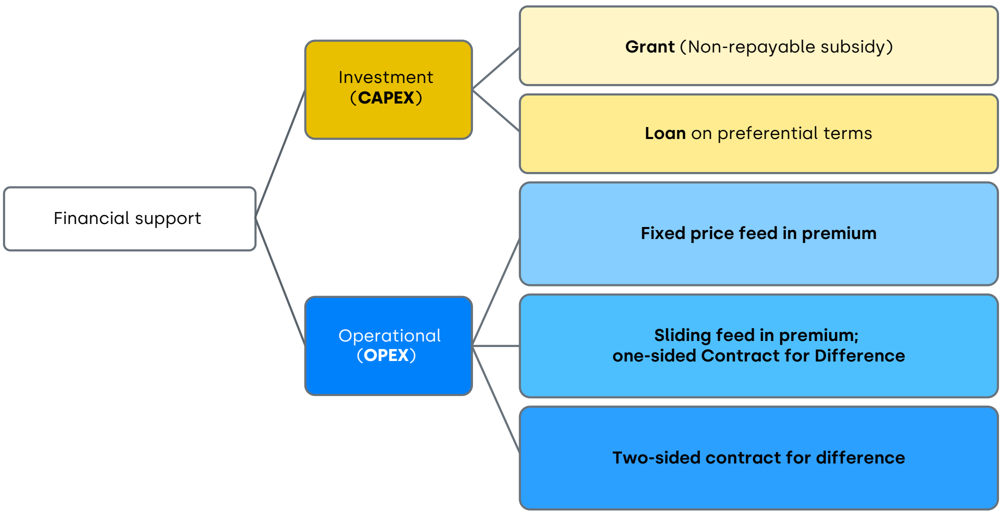
29 OPINION OF THE ENERGY FORUM on possible Polish actions around the Competetiveness Fund.

30 Guidelines on state aid for climate protection and environment and energy-related targets of 2022 can be viewed HERE.

4. How to support electrification with domestic funds?

Regardless of the planned EU initiatives and available funds, Poland should immediately implement instruments to support companies in raising capital for investment and in the subsequent stabilization of costs after electrification. Below are several mechanisms to ensure adequate support for companies in the industrial processing sector. They concern investment support and operational support. In the latter case, we consider only mechanisms linked to the volume of heat produced. We omit other possible solutions, in particular subsidies for the purchase of electricity (e.g., in the form of a contract for difference) as excessively distortive solutions for the energy market, and Carbon Contracts for Difference as instruments too complex at the early stage of promoting electrification in Poland.

Figure 15. Types of financial support



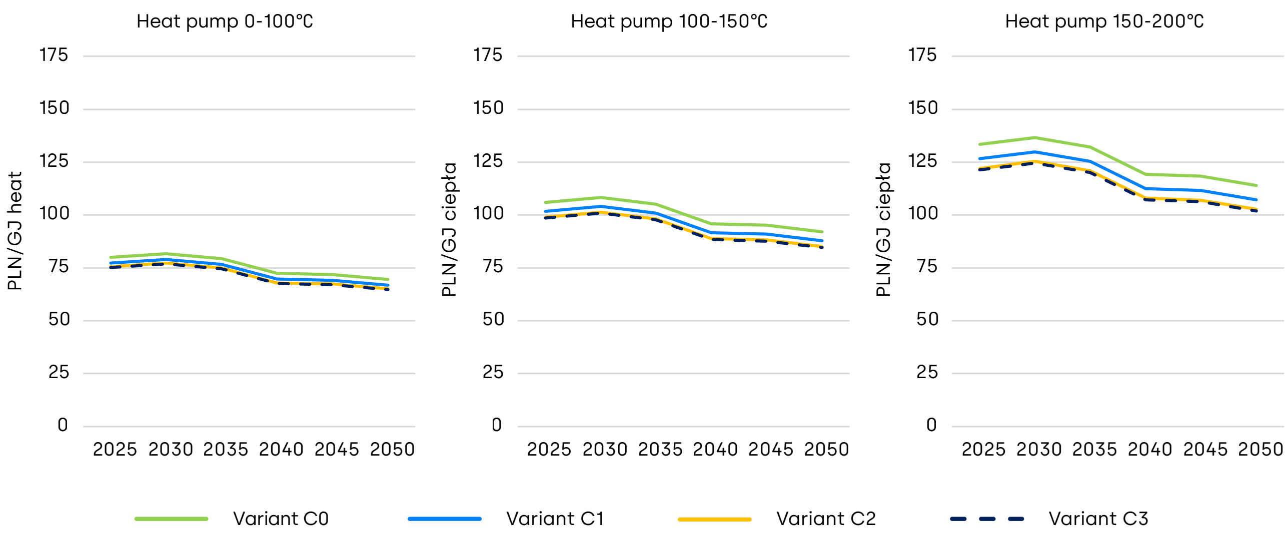
4.1. Investment support

One possible incentive is to reduce the initial investment cost through a subsidy from the state budget on attractive terms or low-interest loans offered by a Polish financial institution such as BGK. Several variants of possible support and the impact on the total life cycle cost of heat (LCOH) are presented below.

Table 2 Assumptions for possible investment support programs

Name of the variant	Assumptions
Variant C0	No investment support mechanisms
Variant C1	Non-refundable funding for 30% of total investment costs
Variant C2	Non-refundable funding for 50% of total investment costs
Option C3	Non-commercial 0% credit for total investment costs

Figure 16. Impact of individual investment support schemes on the total cost of heat from industrial heat pumps



Source: own study by the Reform Institute

The analysis shows that investment support alone will not induce industry to electrify. The total cost of producing electrified heat will remain high even with 50% non-refundable subsidies. As we pointed out earlier, it is therefore necessary to supplement subsidies with appropriate operational support mechanisms. Thanks to them, the industry will not only start large-scale investments in the electrification of plants but also prepare for structural changes in the energy market.

4.2. Operational support

4.2.1. Feed-in-premium

Fixed-price feed-in premium contracts are a mechanism of a subsidy calculated per amount of emission-free heat produced. Their main advantage is their simplicity and the ability to easily conduct a competitive auction in which consumers compete by offering the lowest expected support rate. The disadvantage of this mechanism is that there is no hedging against the risk of changes in the price of energy carriers, since both the benefits and costs of changing price trends remain with the customer. In the case of recipients with hybrid installations, this provides the opportunity to switch between supported carbon-free heat and other sources.

4.2.2. Differential contracts

Differential contracts for heat are an effective way to stabilize operating costs of electrification. Support should be technology-neutral, i.e., equally rewarding different forms of zero-emission heat production, whether electric boilers and heat pumps or alternative zero-emission technologies such as geothermal. Possible solutions to be introduced in Poland are:

A sliding feed-in premium

The variable amount of unit support depends on the difference between the current actual cost of generating heat in a zero-emission (electrified) source and the cost of a fossil-fuel alternative, such as a gas-fired boiler. The value of the support drops to zero when the profitability curves of the two technologies intersect.

Two-sided Contract for Difference

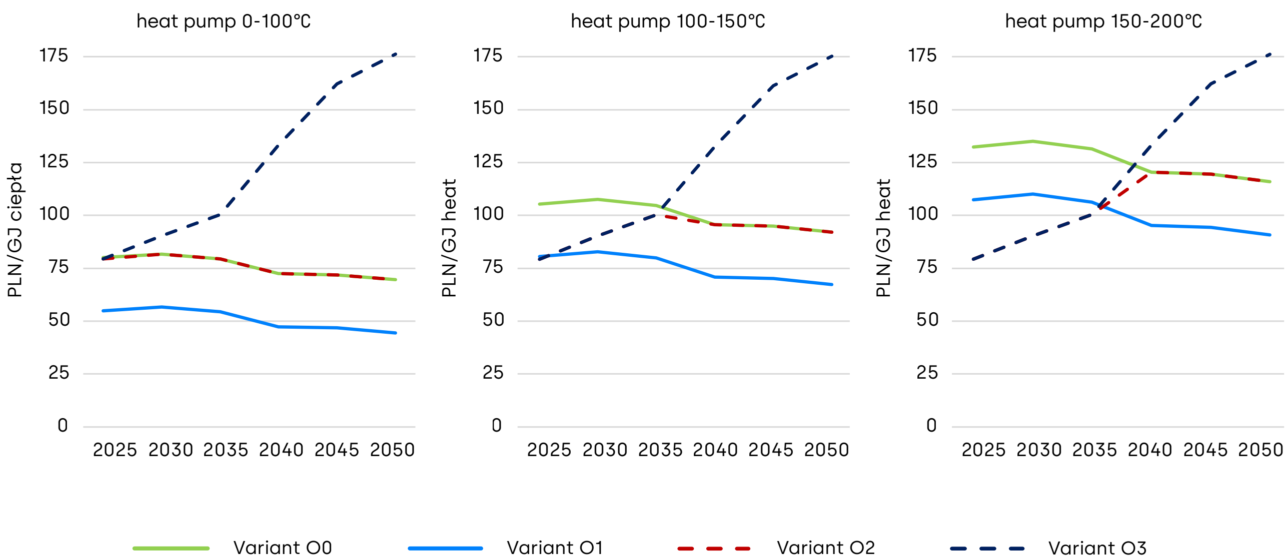
This support mechanism works similarly to a one-sided contract. However, if the price relationship is reversed, the recipients return part of the support they received. This ensures that losses are compensated for on the one hand, while limiting benefits in the event of, for example, a gas crisis. This ensures that beneficiaries do not gain an unjustified market advantage.

Below is a simulation of the impact of various subsidies on the total cost of heat (LCOH).

Table 3. Assumptions for possible operational support programs

Name of the variant	Assumptions
Variant O0	No operational support mechanisms
Variant O1	Fixed price feed-in premium of 25 PLN/GJ of heat generated
Variant O2	Sliding feed-in-premium: Variable unitary amount of support depending on the difference between the current real cost of heat generation in the heat pump and the cost of heat generation in the reference gas source. Support may not take negative values.
Variant O3	Two-sided contract for difference: Variable unit amount of support depending on the difference between the current real cost of heat pump heat generation and the cost of heat generation in a reference gas source. The support may take negative values (i.e., the beneficiary may pay the difference to the support provider).

Figure 17. Impact of different operational support schemes on the total cost of heat production from industrial heat pumps



Source: own study by the Reform Institute

Table 4. Averaged cost of support over the 2030-2045 period for various operational support mechanisms

Averaged support cost for the period 2030-2045 (15 years)	Heat pump 0-100°C	Heat pump 100-150°C	Heat pump 150-200°C
Variant O1: Fixed price FIP	25 PLN/GJ	25 PLN/GJ	25 PLN/GJ
Variant O2: Sliding FIP	1 PLN/GJ	12 PLN/GJ	30 PLN/GJ
Variant O3: CfD	-31 PLN/GJ	-3 PLN/GJ	27 PLN/GJ

Source: own study by the Reform Institute

The analysis presented here shows that **sliding feed-in-premiums** (subsidizing the cost difference between the electrified and traditional variants) **are a sustainable and effective way to support the electrification of medium – and low-temperature heat.**

This solution ensures that the investor achieves cost parity and does not generate the risk of having to pay back the funds in the 2040s, when it may not be possible to pass on the additional costs of emission to end users (in view of the widespread decarbonization of other market participants). At the same time, the state does not pay out funds when electrification becomes profitable without subsidies.

5. Recommendations

5.1. For businesses

The primary barrier to electrification is the low cost-effectiveness for the majority of applications, due to relatively high operating costs. However, the energy sector is changing dynamically – the increasing availability of renewable electricity sources and volatile market prices mean that electricity will become the cheapest energy carrier. This trend will intensify. Industry should prepare for the energy transition today to avoid losing competitiveness.

Key actions include:

1. **Considering the costs and benefits of the energy transition.** Companies should adapt to this trend today by adopting price scenarios in business plans that promote the use of electricity.
2. **Investment in hybrid installations.** Hybrid installations that allow alternate use of electricity and fossil fuels can already achieve cost-effectiveness at selected plants and at the same time promote flexibility in the electricity system. Having the ability to power from two independent sources increases resilience to price fluctuations and decreases risks associated with importing raw materials such as natural gas in the event of another energy crisis.
3. **Planning investments in full electrification of heat sources now.** Business leaders should consider building their own RES sources and/or direct electricity connections to RES and conduct cost-effectiveness analyses for various electrification options.
4. **Be more active in taking advantage of available public support funds.** Polish companies should actively use available EU funds, especially in the context of anticipated changes in the EU's approach to investment financing.

5.2. For public policy

Electrification of industry should be seen as a natural direction for its development. In order for the industry to adapt to the new reality, such as increasing the flexibility of electricity consumption, active legislative and regulatory support is needed.

Below are our recommendations to the government and regulator:

1. **Reduce fees and taxes included in the electricity bill to lower the cost of electricity.**
2. **Abolish subsidies that support fossil fuels.**
3. **Eliminate mechanisms that support inflexible electricity use:**

- Eliminate the CHP premium or its suspension during hours of low electricity prices;
- Changing the method of calculating the capacity market fee for industrial customers to stop penalising a flexible consumption profile.

4. **Introduce incentives for flexible energy consumption,** such as:
   - subsidies for electric boilers operating during high-RES generation hours;
   - application of dynamic pricing of the electricity grid variable fee;
   - reducing the amount of the fixed grid rate for electrode boilers;
   - revision of power charge adjustment factors to encourage flexible energy consumption.
5. **Revision of grid fees by the URE toward dynamic tariffs**[31]. Already today, some DSOs are introducing grid fees moving in the direction of dynamic network charges.[32]
6. **Promote awareness of the energy transition (including the updated NECP) and available public support programs** among all industrial processing entities.
7. **Launch operational support for electrification.** Analyse the possibility of introducing sliding feed-in-tariffs for industrial processing by 2035. Support programs should be simple and effective (with clear and attractive rules for business) and but not excessively burdensome for public finance.
8. **Actively seek synergies with efforts to decarbonise system heat,** particularly in terms of supply chain building, local competence and regulatory experience (e.g., in terms of grid fee changes or developing support instruments).

31 You can read more about dynamic network fees in the Reform Institute's report FIXED, VARIABLE, OR DYNAMIC? NETWORK CHARGES IN THE FACE OF THE ENERGY TRANSITION.

32 You can read more about it HERE.

Appendix:
Cost environment for direct electrification

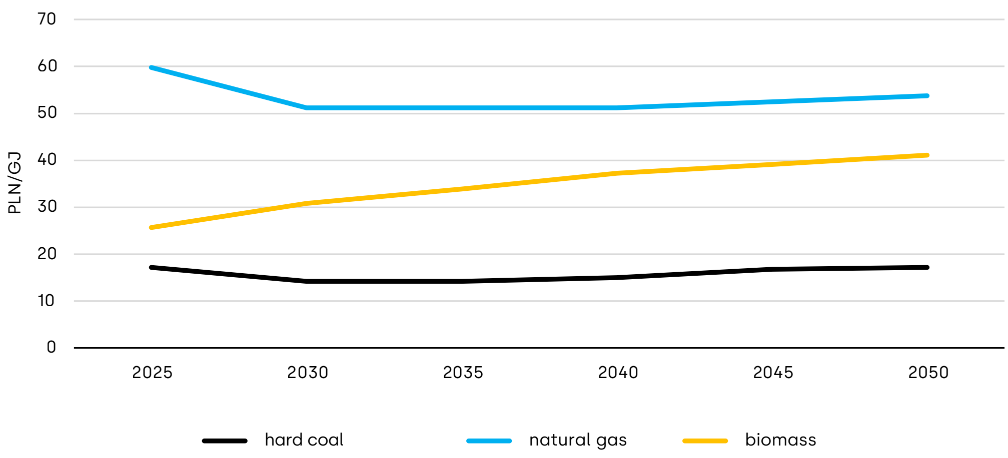
The following are the key cost assumptions used to perform the quantitative analyses presented in the publication.

Fuel prices

Fossil fuel prices (coal, natural gas) were assumed in accordance with the National Energy and Climate Plan. These prices do not include the cost factor associated with the ETS2.

Biomass prices were determined based on current prices for this commodity on wholesale markets. A systematic but conservative increase in its cost over the long term was also assumed. This means that this forecast does not take into account the scenario of a spike in the price of biomass due to a dynamic increase in demand for it.

Figure 18. Fuel price assumptions



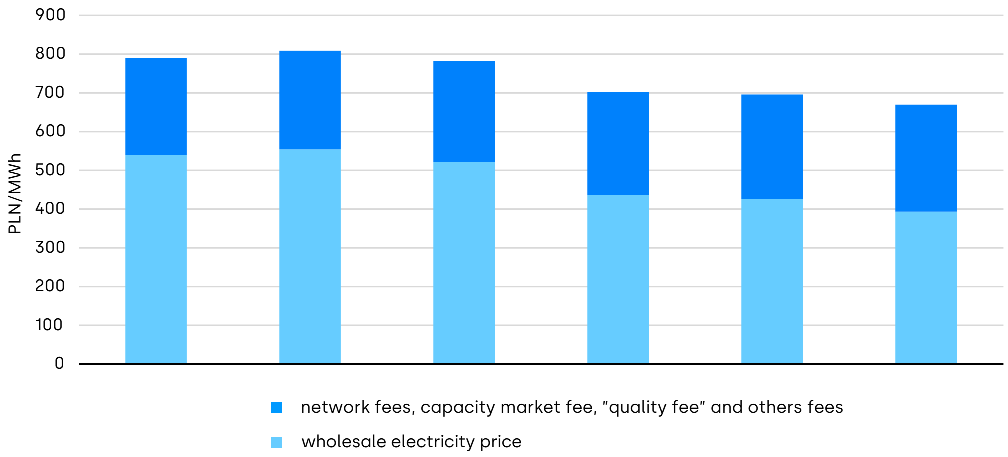
Source: Reform Institute based on the NERC

Electricity prices

Electricity prices in the Day-Ahead Market were adopted based on the results of an analysis performed by the Energy Market Agency (ARE) on behalf of the Reform Institute. The cost of the variable component of electricity for industry was assumed to be 10% higher than the weighted average price of electricity on the wholesale market in a given year.

The amount of network charges was assumed on the basis of the current distribution tariffs for tariff group B, and its systematic increase was assumed, because of the increase in investment in electricity grid infrastructure.

Figure 19. Electricity price assumption

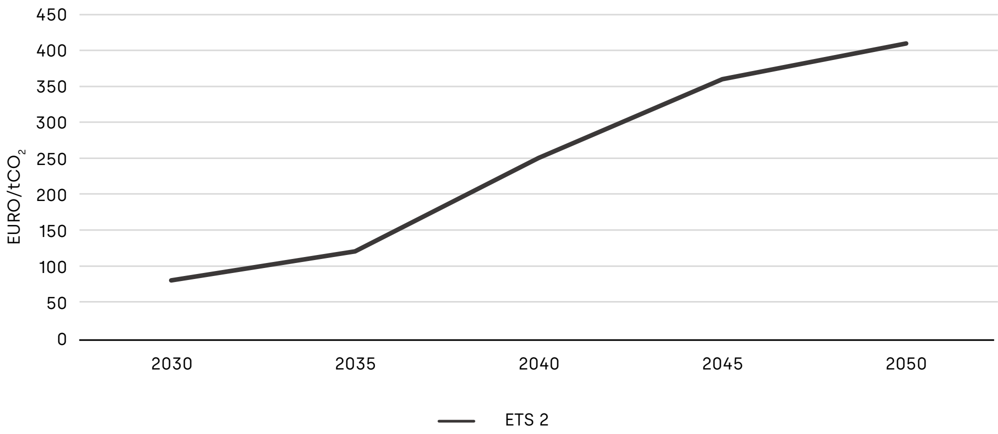


Source: Reform Institute based on analysis by ARE

Prices for CO_2 emission allowances

Prices for CO_2 emission allowances in the ETS2 are based on assumptions for the NECP and European Commission guidelines

Figure 20. Price assumptions for the price of CO_2 allowances in ETS2



Source: Reform Institute assumptions based on NECP projections and EC guidelines

Gas cogeneration

For the purpose of the analysis (Figure 6) of the amount of LCOH for gas cogeneration, the component of the cogeneration premium was not included.

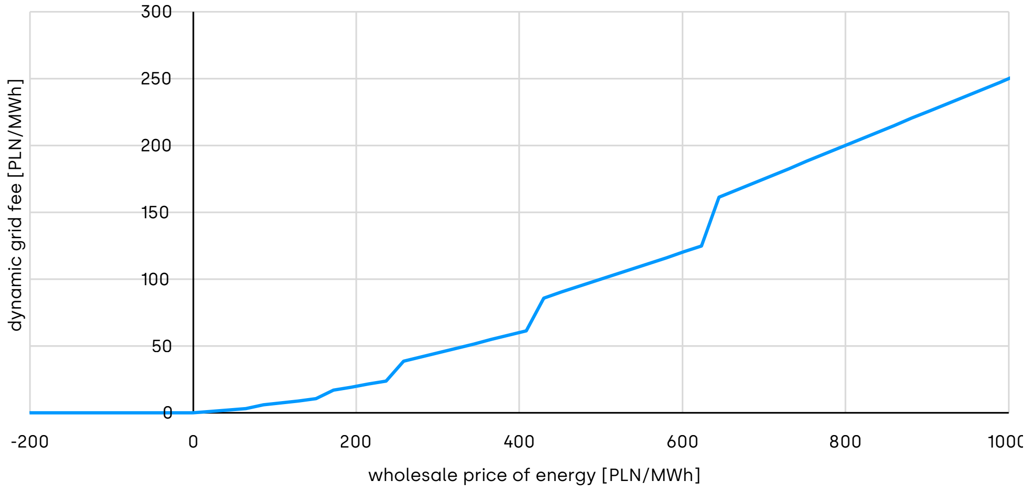
The impact of the CHP premium of PLN 200/MWh on the cost-effectiveness of the operation of a CHP unit cooperating with an electrode boiler is included in the analysis in Section 2.2.

Dynamic tariffs and dynamic grid fees

Energy prices in the dynamic tariff were adopted in accordance with the previously mentioned analysis by ARE.

The calculation of dynamic grid fees is an internal assumption of the Reform Institute. These assumptions make the size of the variable network rate dependent on the electricity price in the Day-Ahead Market. These simplified assumptions do not take into account potential mechanisms for shaping dynamic network charges related to the possible occurrence of local distribution network load problems.

Figure 21. Assumptions for dynamic grid fees



Source: Reform Institute assumptions

Variant analysis of the operation of the hybrid installation with and electrode boiler and a cogeneration engine

The assumptions for the boundary conditions of the different variants presented in Section 2.2 are shown below.

Table 5. Considered variants of operation of the sole natural gas cogeneration engine and the hybrid system with the electrode boiler as well

Assumptions	Electrode boiler	Electricity tariff	Fixed component of the grid rate	Capacity market fee	CHP premium
Variant 0	NO	Dynamic	Full	A 100%	YES
Variant 1	YES	Dynamic	Full	A 100%	YES
Variant 2	YES	Dynamic	Full	A 100%	YES
Option 3	YES	Dynamic	Reduced by 50%	A 100%	YES
Variant 4	YES	Dynamic	Full	A 17%	YES
Variant 5	YES	Dynamic	Reduced by 50%	A 17%	NO

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