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Adequacy of the electricity system development implied in the NDC2-draft

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About Low Carbon Ukraine

Low Carbon Ukraine is a project that continuously supports the Ukrainian government with demand-driven analyses and policy proposals to promote the transition towards a low-carbon economy.

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Executive summary

Ukraine's draft 2nd NDC (NDC2) envisions an economy-wide reduction of emissions from ca. 340 megatons of CO_2 equivalents (Mt_{CO2eq}) in 2018 to ca. 290 Mt_{CO2eq} in 2030. It projects that the electricity sector will ensure roughly 45% of the total projected emission reductions from now until 2030[1].

To achieve these emission reductions and simultaneously create a well-functioning electricity system, investments of approx. EUR 27 bn in the energy system (including electricity and CHP generation) until 2030 are needed.

These EUR 27 bn would enable the necessary:

a) construction of 17 GW renewable electricity sources, installation of 1 GW of OCGTs and batteries and 1.2 GW renewable combined power and heat, as well as the
b) NERP-compatible lifetime expansion of existing power plants. This requires the retrofitting of approx. 14 GW thermal electricity capacities (including 5.5 GW CHP).

The resulting electricity system in 2030 would be appropriate to securely generate above 185 TWh (gross electricity generation), being able to meet a net demand of 150 TWh.

Realising this transformation of the energy sector successfully would cause the carbon intensity of net demand to decrease from approx. 360 g/kWh in 2020 to 190 g/kWh in 2030. This represents abatement costs of approx. 40EUR/ton of CO_2-equivalent, similar to current levels of the EU ETS.

Meanwhile, the necessary investments would increase the aggregated electricity generation costs from EUR 7 bn in 2020 to EUR 12.5 bn in 2030. This represents generation costs of 83 EUR/MWh – compared to 59 EUR/MWh in 2020. This is an increase of 41%.

However, even without the installation of new RES capacities, investments in new capacities and the NERP-compatible life-time expansion of at least 14 GW of thermal power plants (TPPs) are necessary to meet future electricity demand. The respective annual generation costs would thus increase to EUR 11.2 bn, or 75 EUR/MWh, representing an increase of 27% compared to 2020.

To ensure the flow of private investments and the ability of generators to finance their operations, reforms in the electricity market are of high importance. E.g., current transmission tariffs are too low to pay for the two Ukrainian public service obligations. Additionally, aggregated generation costs exceed system-wide revenues by approx. EUR 1 bn annually, mainly because Energoatom does not receive cost-covering electricity fees. For the same reason, Energoatom is not able to adequately maintain its fleet of nuclear power plants with the current fixed price it receives for its electricity.

We can show that the investment needs estimated in the Ukraine NDC draft are adequate to achieve planned emission reductions in the sector. Furthermore, the emerging system structure enables a higher security of supply. Resulting generation costs are approximately 41% higher compared to today's costs but would kick-start a long-term climate-friendly transformation of the Ukrainian economy. With abatement costs of only 40 EUR/ton CO2, the electricity sector can compete with other sectors' costs for reducing emissions. Finally, it is important to generate an investor-friendly business environment through a robust and reliable policy framework and to transform the Ukrainian economy towards a greener and more sustainable growth path. This would further reduce generation costs due to lower risk premia and interest rates. The approval and implementation of the Ukrainian NDC2 will support this transformation.

[1] https://mepr.gov.ua/news/37144.html?fbclid=IwAR2GuJOp2QgL7yFgknw9C8dciMbVmp_IyJMoFdjTDld4N6Tq2ceX2xaiwyo, Ministry of Ecology of Ukraine, assessed on May 4th, 2021

1 Role of the electricity sector in the NDC

1.1 Emission reduction contribution of the electricity sector

Ukraine's electricity system plays a key role in the country's plan to reach its emission targets for 2030. These targets were recently published in the draft 2nd NDC (NDC2) of Ukraine's Ministry of Ecology[2].

All in all, the NDC2 envisions an economy-wide reduction of emissions from ca. 340 megatons of CO_2 equivalents (Mt_{CO_2eq}) in 2018 to ca. 290 Mt_{CO_2eq} in 2030. This accounts for a substantial reduction in emission intensity, as Ukraine's plan also foresees a simultaneous annual economic growth of at least 3%. In the case of no additional policies, the NDC2 projects emissions to increase to almost 400 Mt_{CO_2eq} by 2030. Thus, Ukraine plans to decouple economic and emission growth.

The electricity sector will ensure roughly 45% of the total projected emission reductions from 2021 until 2030. This means that out of every two saved tons of CO_2-equivalent emissions in 2030, almost one will be saved in the electricity sector.

In 2018, Ukraine produced ca. 150 TWh of electricity, emitting approx. 48 Mt_{CO_2eq}. In 2030, electricity production will have grown to ca. 190 TWh, as projected by the NDC2's underlying modelling. Meanwhile, total emissions will have decreased to 28 Mt_{CO_2eq}. The NDC2 plans to achieve this by investing into the construction of new electricity infrastructure, as well as into the renovation of existing facilities. Without these investments in new – mainly renewable – capacities, we find emissions of the electricity sector to grow to approximately 60 Mt_{CO_2eq} in 2030.

In 2030, electricity and heat production combined will still make up 21% of Ukraine's emissions. However, as can be seen in Figure 1, the largest share will come from Industry (29%). In comparison to the base year of 1990, to which all NDCs' targets are compared, the energy industries of Ukraine will have saved the most emissions by 2030: Every third saved ton of CO2-equivalent emissions will be saved by electricity or heat plants (Figure 2).

Figure 1: Sectoral emission 2030 (shares)

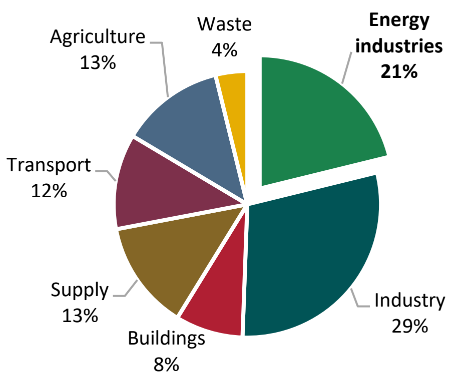
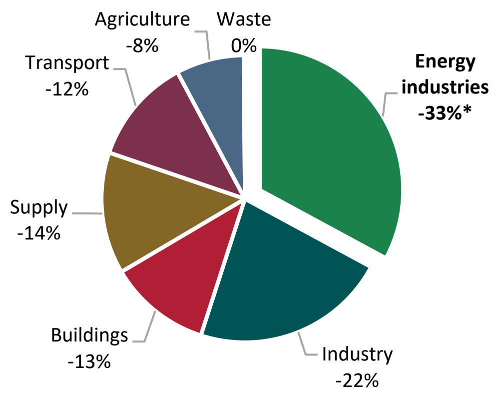


Figure 2: Share of emission reductions (2030 vs. 1990)[3]



Source: Ministry of Environmental Protection and Natural Resources of Ukraine (2021)

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[2] https://mepr.gov.ua/news/37144.html?fbclid=IwAR2GuJOp2QgL7yFgknw9C8dciMbVmp_IyJMoFdjTDId4N6Tq2ceX2xaiwyo, Ministry of Ecology of Ukraine, assessed on May 4th, 2021

[3] For 1990, no disaggregated data for emissions from heat plants and electricity plants exist, which is why they are grouped together in these figures.

1.2 Investment needs

The emission reductions in the NDC2 imply investing roughly EUR 100 bn over the next ten years. Overall, approximately 27% of the upcoming decade's investment needs to meet the NDC2-targets will go into electricity and heat infrastructure. This amount corresponds to somewhat more than EUR 27 bn.

As can be seen inTable 1, for the installation of new renewable electricity-only capacities, such as wind, solar and biogas/-mass EUR 17 bn have to be spent. EUR 1 bn are needed for the installation of additional flexibility options (OCGT and batteries). The installation of new biomass-based combined heat and power plants requires further investments of EUR 4.6 bn. Because thermal fossil capacities will be still needed after 2030, a NERP-compatible retrofitting, including a lifetime extension of approx. 10 years, is needed. These activities will require further investments of approx. EUR 4.3bn[4].

Table 1: Overview necessary investments to reach NDC2 targets

	GW	bn EUR
New installations 2021 - 2030	**19**	**23**
Electricity Generation and Storage	18	18
Renewables	16	17
OCGT	1	0.5
Batteries	0.7	0.5
CHP	1.2	3.6
Heat	N.A.	1
Retrofitting / NERP and life-time expansion 2021 - 2030	**13**	**4.3**
Combined heat and power COAL plants	1.6	0.2
Combined heat and power GAS plants	3.7	0.4
Thermal Power Plants	7.5	3.8
Total	**32**	**27**

Source: Own analysis based on NDC2

The depicted investment needs do not include potentially required investments for the retrofitting of existing nuclear power capacities. Most nuclear units will not reach the end of their lifetime before the 2030s. Whether and to what extent nuclear sources will play a role in Ukraine's electricity mix after their dismantling, has to be discussed separately. Furthermore, it has to be evaluated whether new NPPs should provide a contribution to a carbon-free electricity generation besides renewable sources. Thus, the following analysis assumes that all existing nuclear units can safely generate electricity until the middle of the next decade. Therefore, only nuclear power's considerable maintenance costs are included in the subsequent calculations, but no additional investments.

[4] The figure presented in Table 1 is about 5 percent higher than originally projected in the NDC2, as it also takes into account recent developments under Ukraine's draft NERP, which demands more stringent emission standards specifically for non-greenhouse gases:

Ukraine developed the National Emission Reduction Plan (NERP) based on the Large Combustion Plants Directive and the Industrial Emissions Directive (IED). According to NERP, Ukraine's large combustion units (TPPs and CHPs) are subject to aggregated emissions ceilings for each year. These more stringent ceilings are reflected in the 3.8 bn used to renovate thermal power plants in Table 1.

2 Status quo of the Ukrainian electricity system

2.1 Generation mix and flexibility issues

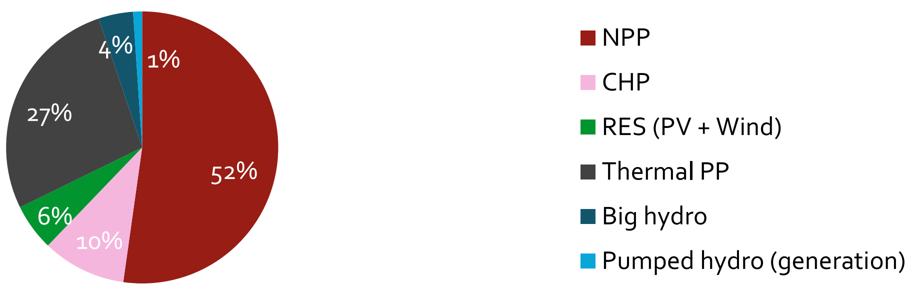
The Ukrainian electricity sector is currently undergoing a deep transformation. Based on generous feed-in tariffs (FITs), the expansion of RES in Ukraine has accelerated in recent years. Since the FIT scheme was introduced, RES capacities have increased rapidly from less than 100 MW in 2009 to 8.5 GW in December 2020. In 2020, wind and PV accounted for 6% of electricity generation (see Figure 3).

The increase in the country's RES expansion targets envisioned in Ukraine's NDC2, as well as a future electrification of the heating and transport sectors will further amplify the need for flexibility in the Ukrainian electricity system. The main challenge for the future electricity grid of Ukraine will be to combine a consistently high share of nuclear baseload generation with a growing share of variable RES. Providing sufficient regulating capacity in a system with growing PV generation, managing high must-run obligations (e.g. during winter, when CHP generation is high), as well as providing operating reserves for frequency stabilization are some of the crucial issues for Ukraine's generation adequacy planning up to the 2030s. The conventional Ukrainian power plant park is dominated by base-load power plants, while peaking power plants are lacking. The backbone of power generation is provided by the four nuclear power plants with a total capacity of 13.8 GW, which cover half of Ukraine's electricity demand. The average operating age of the 15 units operated by the state-owned Energoatom is 32 years, and the regulated purchase prices for the bulk of electricity produced by the nuclear power plants is too low to finance adequate maintenance measures. The regulations of Ukraine's transmission system operator (TSO) Ukrenergo do not provide for load-following operation of the nuclear power plants for safety reasons.

As of 2020, the only supply-side providers of flexibility in the Ukrainian electricity system are hydro, pump-storage and thermal power plants. Although the installed capacities of hydro (4.6 GW) and pump-storage (1.5G GW) can in theory provide significant flexibility at low cost, the irregular availability of water in the Dnieper and Dniester rivers limits the hydro balancing potential. This is true especially during summer, when PV generation and thus balancing needs are highest. Due to the surge in PV capacity additions, Ukraine is increasingly making use of its pumped hydro plants to store the excess supply of PV electricity during noon hours. New pumped hydro facilities of 2.9 GW are planned but delayed. From a technical point of view, Ukraine's 19.3 GW of thermal plants (of which 15.5 GW are coal- and 3.8 GW are gas-fired) offer sufficient flexibility to balance high RES shares. Their high average minimal load of 66%, however, means that many thermal units need to be kept spinning to provide sufficient up- and downwards flexibility, thus pushing inflexible nuclear units – which incur less variable cost and emissions – out of the system. Relying on Ukraine's current thermal fleet as the main provider of balancing services could therefore lead to both higher operational costs and higher emissions.

Furthermore, the future of Ukrainian coal fired power plants will depend on the way Ukraine implements the National Emission Reduction Plan (NERP), which is based on the EU's Large Combustion Plants Directive and the Industrial Emissions Directive (IED). The NERP implies that all existing large combustion plants, i.e., TPPs and CHPs, either need to be environmentally upgraded or closed by 2034 at the latest if they do not already comply with IED requirements. This implies significant retrofitting or replacement costs.

Figure 3: Electricity generation mix Ukraine, 2020



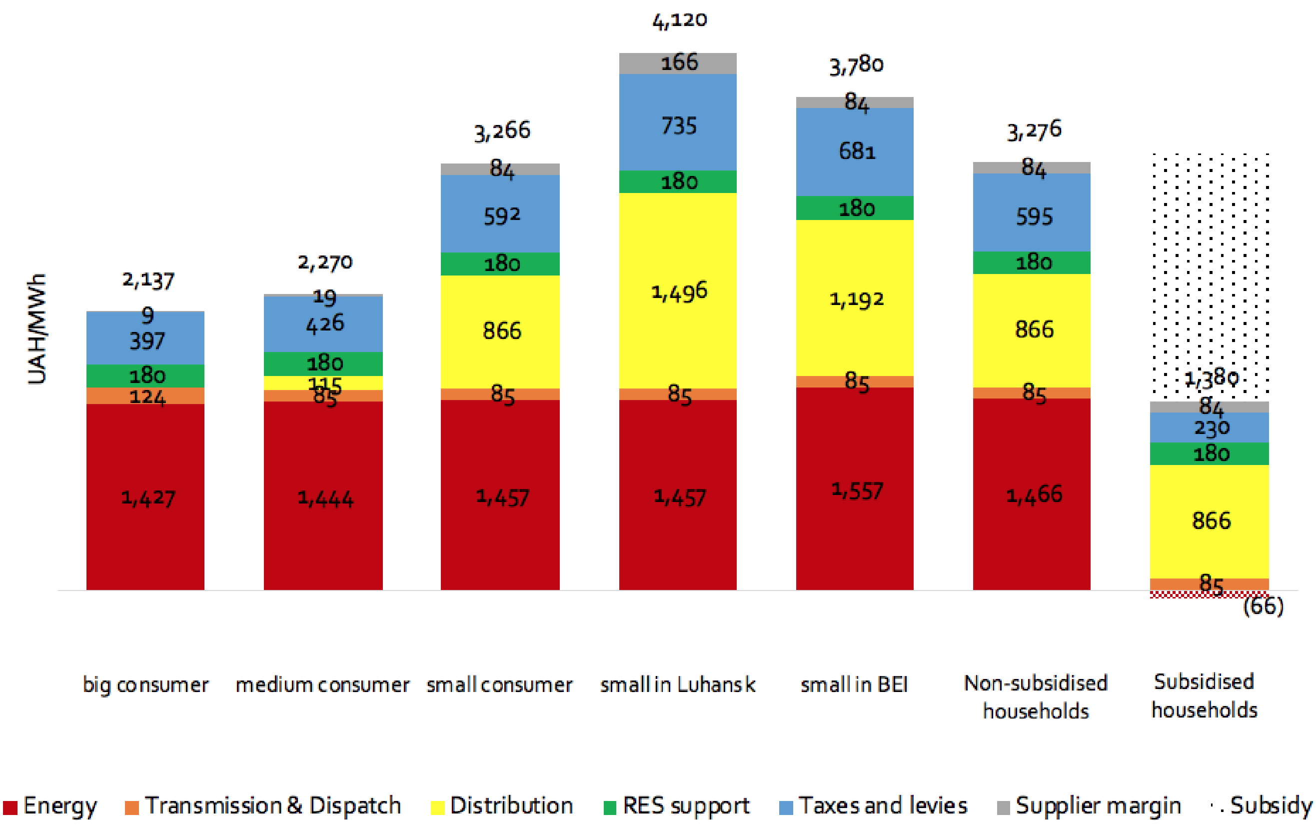
Source: Ukrenergo

2.2 Household subsidies and the cost-recovery challenge for nuclear

Household electricity tariffs are still heavily subsidized in Ukraine (see Figure 4). These subsidies are financed by the obligation of state-owned Energoatom – the operators of Ukraine's nuclear plants – to sell most of its output (i.e. the total amount of electricity consumed by households) at non-cost-recovering prices to the single offtaker Guaranteed Buyer (GB). Ukrhydroenergo, the state-owned operator of hydro plants, also has to sell 30% of its output virtually for free to the GB. The GB resells the electricity to suppliers and consumers. The subsidies are also financed indirectly by non-residential consumers paying higher wholesale prices due to decreased competition. Figure 4 shows the estimated subsidy for household consumers in Ukraine. The GB manages not only the Public Service Obligation (PSO) of supplying households with electricity at regulated prices, but is also responsible for the PSO of RES support. RES producers in Ukraine that are eligible for FIT sell their electricity to the GB, who then resells all RES electricity at the regular day-ahead market (DAM) or on the bilaterals segment. The difference between FITs (or future auction prices) and wholesale prices is the premium that is financed by TSO tariff surcharges for consumers as well as electricity sales from state-owned companies. At fixed support (i.e. FIT) levels, the level of wholesale prices therefore determines how much one kWh of green electricity is subsidised in Ukraine.

Because the transmission tariff, however, is too low to fully finance the RES support costs, the GB is heavily indebted. The GB's second PSO for households adds to the debt problem – regulated household tariffs are even lower than the GB's expenses for regulated nuclear electricity plus transmission and distribution costs as well as a regulated supply margin in some regions of Ukraine. As of December 2020, the GB had accumulated EUR 650 mln in debts from the RES PSO and EUR 230 mln from the household PSO.

Figure 4: Estimated final electricity prices 2021

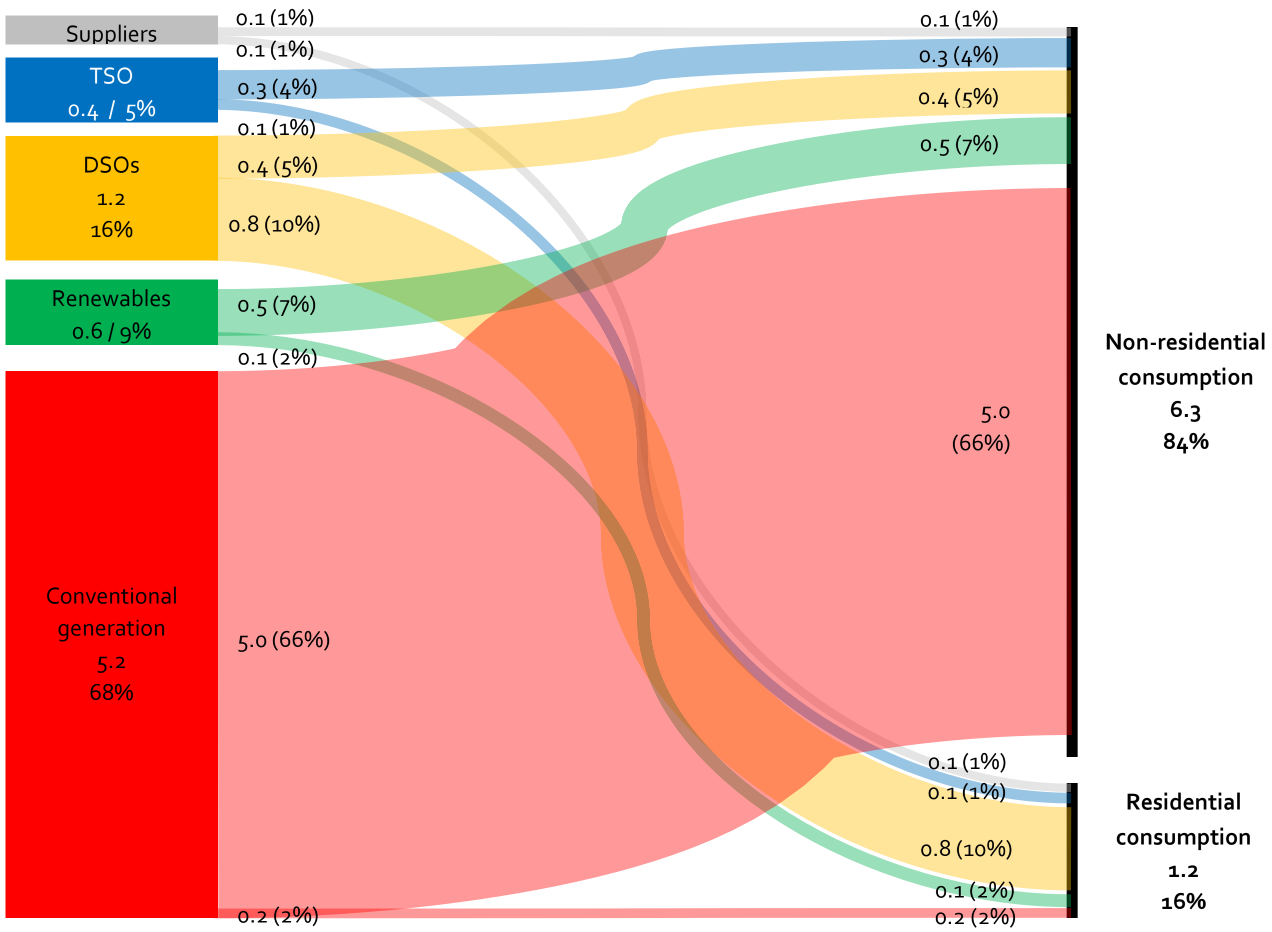


Source: Own calculations

Not only the financial intermediary GB is suffering from insufficient income to finance its operations. Because of the PSO system, there is a substantial gap between what certain generating companies pay – or should pay – for fuel as well as operation and maintenance of their power plants cost on one side and their income from electricity sales on the other. These economic losses become visible when comparing aggregate generation costs and electricity sales revenues.

However, this gap is not the same for every player on the supply side: While private operators of thermal plants enjoy positive margins through electricity sales on spot and bilateral market segments, the burden is almost exclusively carried by state-owned generators, which are prevented by the PSO regulation from selling all of their output at high Ukrainian spot market prices and have to sell at below-cost prices to the GB instead. Figure 5 shows our estimate of 2020 turnover on Ukraine's electricity market (without depicting intermediaries such as the GB). This estimate is based on actual payments by consumers for electricity – unpaid bills are not included. Total turnover for operators of conventional and renewable power plants amounted to EUR 5.8 bn, which for the most part came from non-residential consumers – they paid 5 bn EUR to conventional and EUR 500 mn to RES operators.

Figure 5: Ukraine's electricity market turnover 2020, bln EUR

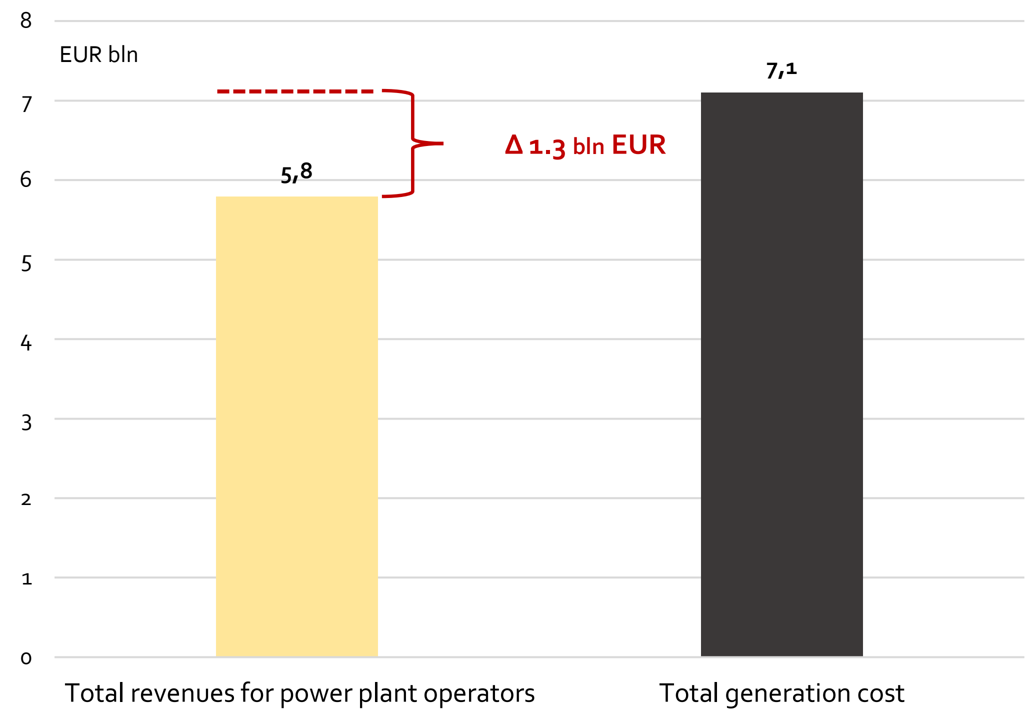


Source: Own calculations

While total revenues for power plant operators in Ukraine amounted to 5.8 bn EUR in 2020, we estimate total 2020 generation costs for the Ukrainian electricity system at 7.1 bn EUR (see Figure 6 and page 12). This estimate comprises fuel, adequate operation and maintenance (O & M) as well as current RES support cost for the 2020 power plant park and generation mix. Fixed O & M costs are especially high for nuclear (111 EUR/kW-year, based on JRC data), which is meant to represent the costs for adequately maintaining Ukraine's large and aged nuclear fleet. The conservative assumption on fixed nuclear O & M hence explains the high share of O & M costs in total 2020 generation costs (see Figure 12). Yet, we do not include the (unknown) costs of final nuclear waste disposal, which is why total nuclear costs are still underestimated. Our estimate of total generation costs does not include the costs for maintaining the transmission and distribution grid, which are paid by final consumers to DSOs and the TSO.

The aggregate gap between operators' income and their expenditures thus amounted to approx. 1.3 bn EUR in 2020. For the different market players, however, the size and sign of this gap varies significantly. Energoatom, which has "true" generation costs of approx. 3.8 bn EUR according to our estimates and has reported only 1.3 bn EUR in net sales revenue[5] in 2020, shoulders most of the aggregate cost-revenue gap. Privately owned thermal generation, on the contrary, is likely to have made significant profits due to high Ukrainian spot prices and largely unregulated bilateral intragroup trading.

Figure 6: Aggregate cost-revenue gap for Ukrainian power plant operators 2020



Source: Own calculations

[5] https://www.ukrinform.net/rubric-economy/3226825-energoatom-expects-to-receive-uah-1b-in-net-profit-for-q1-2021.html

3 Adequacy of the electricity system development implied in the NDC2

3.1 Introduction

Three key properties of an electricity system need to be assessed to determine its viability:

a) Resource Adequacy
b) Investment Adequacy
c) Adequacy of price effects.

Resource adequacy is given if the installed generation capacities are able to meet the demand at all times. Thereby, the generation facilities' specific technological constrains have to be taken into account, such as ramping constraints, fuel constraints, outage periods and similar characteristics. They determine the individual facilities' contribution to an ideally economically efficient dispatch. With the "Optimal Dispatch Model" (ODM V1.51), the LCU project possesses the ability to assess the resource adequacy of electricity systems an under different scenario assumptions. Chapter 3.2 presents the results for the NDC2's optimal electricity system.

To appraise the adequacy of the projected investments, the total amount of required investments in the electricity sector can be compared to the investments in the past and in respect of their share of GDP. Both indicate whether investments are plausible from a macroeconomic perspective. In chapter 3.3 such a comparison is conducted.

The adequacy of price effects focuses on the question whether resulting electricity price changes can be borne by consumers. Electricity cannot be easily substituted and its economic importance is high. Rising electricity prices may put households at increased risk of energy poverty. Hence, electricity availability and electricity prices are important for most value chains and profoundly impact the economic development of a country. Currently, price formation for electricity follows market rules only to some extent. For example, the governmental support for renewable energy sources, such as wind, biogas and PV-solar, through either green tariffs or auctioning schemes sets fixed costs for these sources in the system and thus influences the aggregated average electricity costs, that are the basis for final prices. Therefore, the resulting average electricity costs have to be analysed in respect of their viability for the whole economy. This will take place in chapter 3.4.

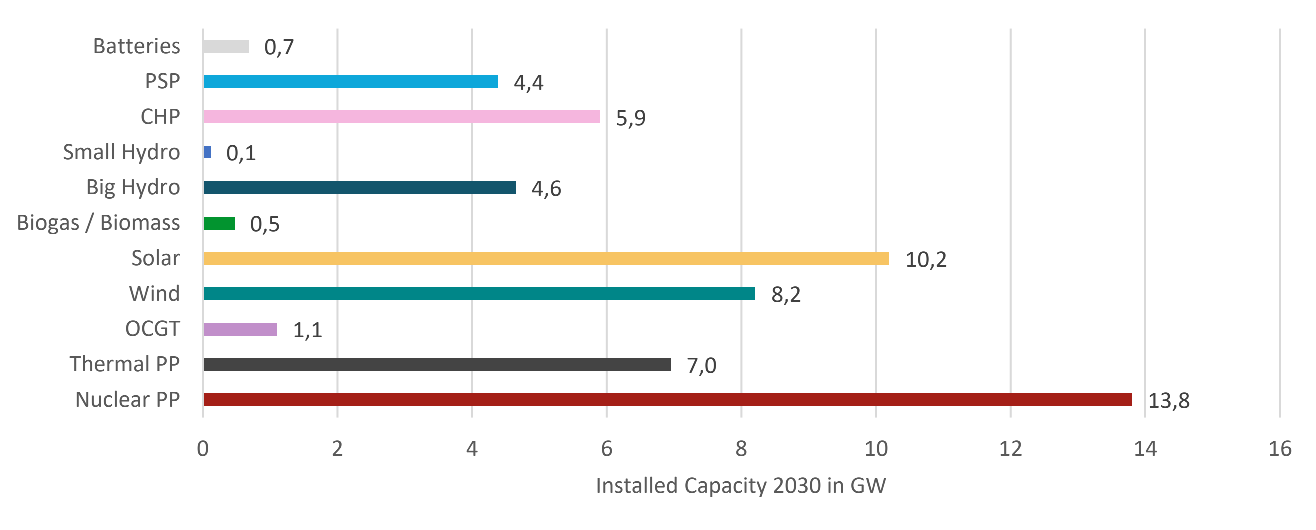
3.2 Resource and system adequacy

The resource adequacy assessment is based largely on the same proposed installed capacities the NDC2's calculations are based on. Roof-top solar and "Autoproducers" (for self-generation) in industry are not considered because they do not feed electricity into the grid. We update overnight cost for new installations based on JRC 2019[4] and investments for NERP- compatible retrofitting of TPP and CHP capacities.

Installed capacities in 2030 NDC Policy Scenario

The total installed capacities in Ukraine in 2030 sum up to approx. 57 GW. Nuclear capacities, big hydro and pump storage capacities remain unchanged in the period of 2021-2030. The main differences result from installations of battery storage (680 MW), Biogas / Biomass capacities (460 MW), utility scale solar (7,200 MW) and wind capacities (5,200 MW) and additional installations of OCGTs (1,100 MW). Furthermore, due to decommissioning, thermal (coal) capacities shrink from 22 GW in 2020 to 7 GW in 2030. Hence, the following capacities will be installed in 2030:

Figure 7: Installed capacities 2030 NDC Policy Scenario



Source: Own assumptions

Aggregated generation

The NDC2 projects the aggregated generation in 2030 to be 192 TWh. Only focusing on generation that is connected to the grid and possibly traded on the market (i.e., ignoring solar roof-top and "Industrial Autoproducer") results in a generation of approx. 185 TWh that have to be covered by the installed capacities presented above. This would serve a total final demand of 155 TWh, assuming some self-consumption by the producers and grid losses of 20% (similar to 2020).

Reserve provision

Actual reserve requirements in the Ukrainian electricity system demand total positive reserves of approx. 2.1 GW and negative reserves of approx. 1 GW. Reserve-providing capacities in the analysis are big hydro, OCGTs and to a small extent also thermal power plants. Even if technologically possible and economically efficient, biogas/biomass as well as wind capacities are not allowed to offer reserves in this analysis, in order to avoid an overestimation of flexibility provision. This is in line with current Ukrainian regulations.

Implementation

The model considers 8 network regions that have capacity-constraint interconnection, a regional distribution of existing (2020) and new capacities as well as region-specific hourly electricity demand curves. The latter are defined by interpolating 2019 aggregated hourly demand and the regional distribution of aggregated demands in 2019.The capacity factors for wind and solar are based on 2019 values, whereby the regional factors are based on observations at 1,000 locations.

Curtailment is allowed for all renewable generation types.

The water availability for big hydro electricity generation is determined by historical weekly aggregated river discharge figures for the rivers Dnieper and Dniester.

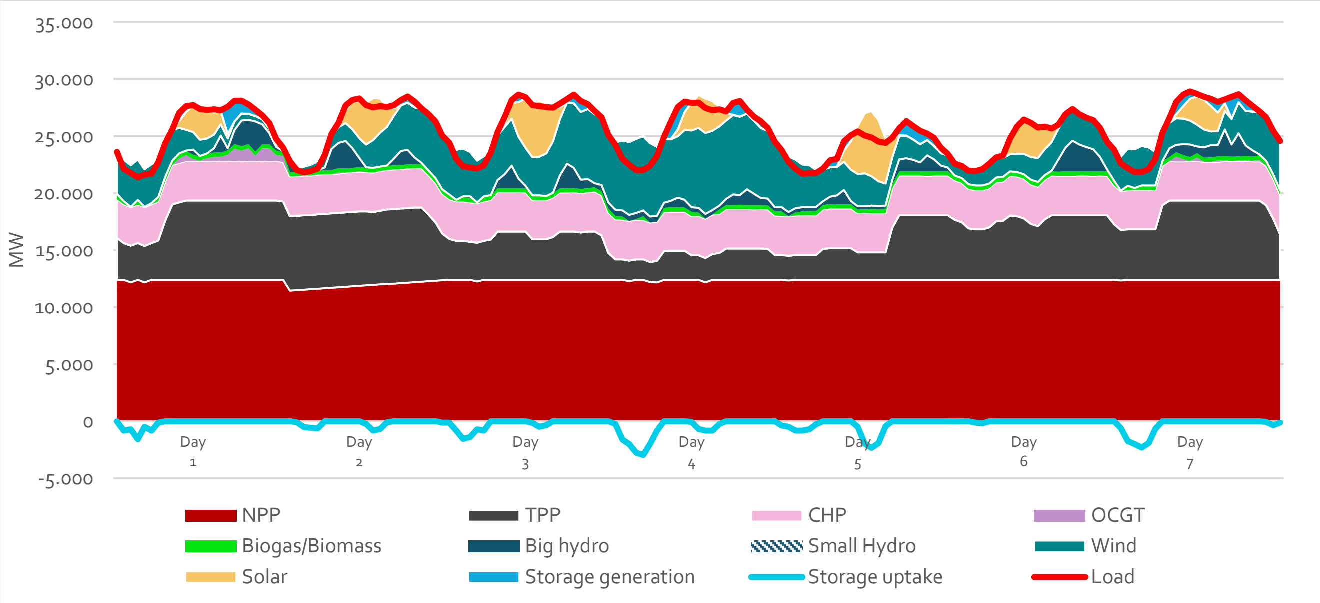
The regional hourly electricity generation by combined heat and power plants generation is set exogenously to 2019 values.

To avoid excessive ramping of nuclear plants due to high RES generation, the nuclear unit status is allowed to only change once a week. To reflect outage times the generation limit is set to 12.4 GW for September till March and 10 GW for the rest of the year.

Results

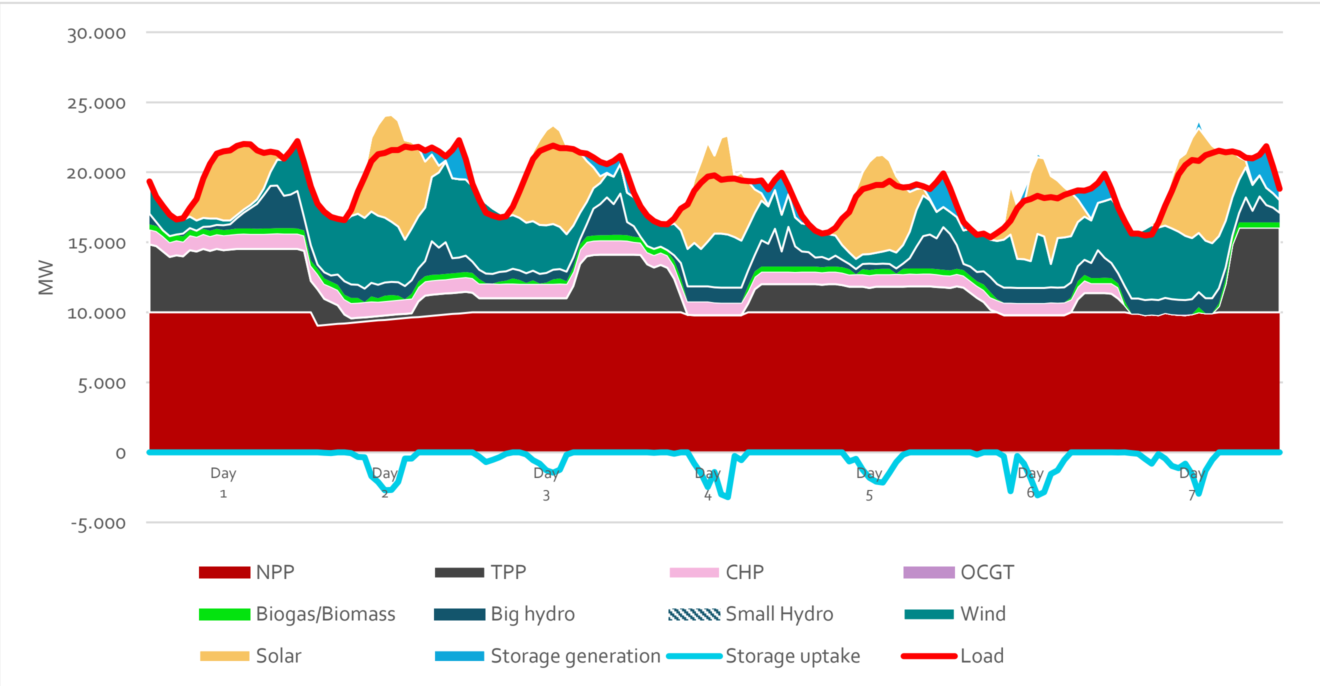
The model results indicate that the described installed capacities are sufficient to meet demand in every hour. The system is thus feasible. The two following figures present the hourly generation for one week in summer and one in winter.

Figure 8: Energy chart, Winter-week 2030 NDC Policy Scenario



Source: ODM model results

Figure 9: Energy chart, Summer-week 2030 NDC Policy Scenario



Source: ODM model results

Total generation (including the use of storage) sums up to 189 TWh. NPP generation has the highest share with 52%. Thermal capacities contribute only approx. 14% to the electricity generation. The share of renewable electricity is 28% (as explained solar rooftop is not included, which would increase this share).

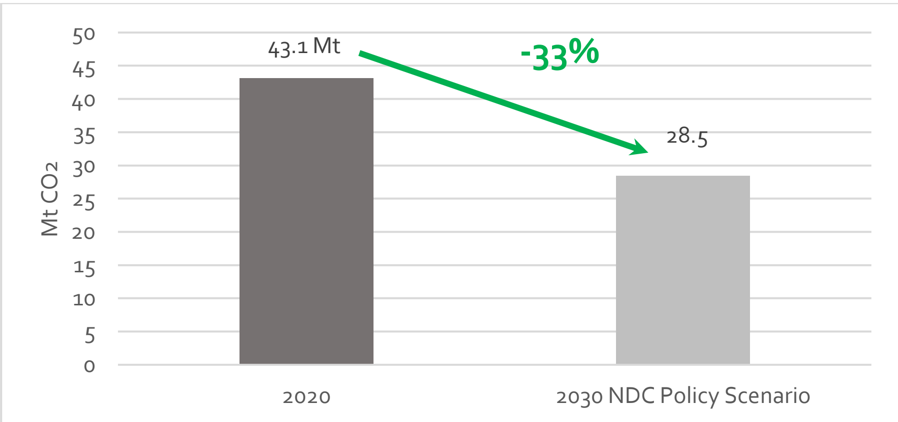
Table 2: Generation and generation shares – 2030 NDC Policy Scenario

	TWh	%
Nuclear PP	96.5	52.0%
Thermal PP	25.6	13.8%
CHP	14.6	7.9%
Incl. CHP BIO plants	*2.6*	-
OCGT	0.3	0.1%
Wind	24.9	13.4%
Solar	13.8	7.4%
Biogas/Biomass	2.6	1.4%
Big Hydro	8.0	4.3%
Small Hydro	0.3	0.2%
PSP/Battery	2.7	1.5%
PSP/Battery uptake	-3.5	
Total generation	**189**	

Source: ODM model results

Low-carbon generation accounts for approx. 80% in the 2030 NDC Policy Scenario, which results in a carbon intensity of 150 g/kWh of gross electricity generation (190 g/kWh of demand, respectively). The total emission of electricity generation decreases from 43 Mt_{CO2eq} in 2020 to 28 Mt_{CO2eq} in 2030.

Figure 10: Emission reduction in the 2030 Policy Scenario



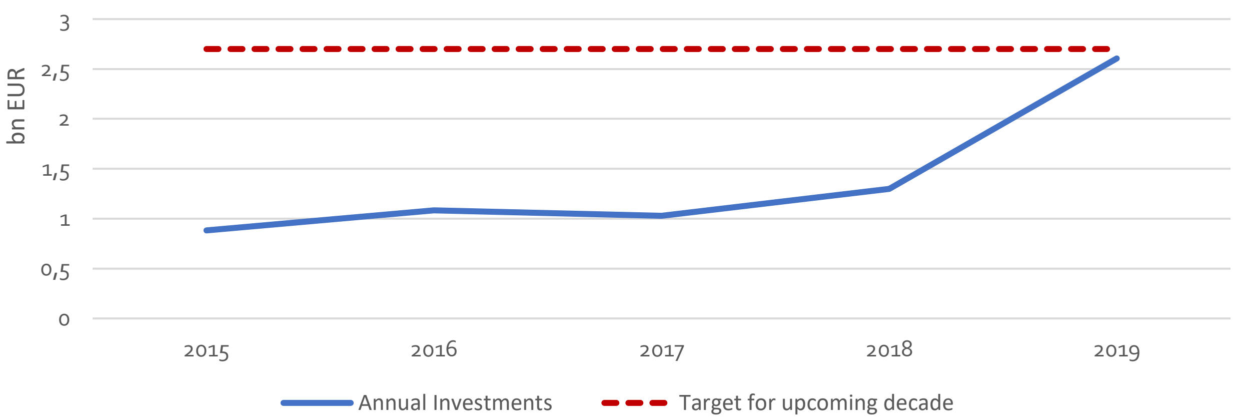
Source: ODM model results

Finding: From a resource adequacy point of view, the proposed development of the Ukrainian electricity system is appropriate to supply enough electricity to meet the net demand of approx. 150 TWh in 2030. Simultaneously, the system is able to provide the required positive and negative reserves by maneuverable sources. The utilization of renewable energy sources will allow for a substantial reduction of GHG emissions. Furthermore, the capacities will be rejuvenated compared to the system characteristics in 2020. This will be of key importance for the further development after 2030.

3.3 Investment adequacy

Average annual investment in the sector "Electricity, gas, steam and air-conditioning supply" from 2010 until 2018 was EUR 1.4 bn. Although this figure comprises also the heating sector, electricity investments are by far the largest part of this aggregation.[6] However, assuming a constant investment rate in absolute terms in this upcoming decade, annual investment needs in the corresponding heat and electricity sectors amount to EUR 2.7 bn. While this is substantially higher than the average investment throughout the last years, investments in the energy sector have recently been on an upward trajectory and nearly reached EUR 2.7 bn in 2019 (see Figure 9 below), mainly owing to the introduction of renewable generation feed-in tariffs. This demonstrates that, while ambitious, it is theoretically feasible for Ukraine to attract the necessary investment funds in the electricity sector provided that adequate incentives for investors exist. The last and quick upward trajectory was however mainly driven by generous governmental feed-in-tariffs (FITs), which have since been lowered. The FITs also resulted in considerable contingent liabilities. It is thus unlikely that investment levels will stay this high.

Figure 11: Annual investments – Energy sector 2015-2019



Note: "Energy Sector" refers to the item "Electricity, gas, steam and air-conditioning supply" in the Ukrainian capital investment statistics.

Source: Ukrstat

Viewed at from another angle, the growth in investments between 2015 and 2019 took place despite a particularly low GDP growth. The average GDP growth was 0.3% - including a recession in 2015 (-9.7%) and moderate growth in 2018 (3.4%). The average annual investment of EUR 1.4 bn from 2010 until 2018 amounts to an average investment over GDP of about 1.2%. Initially, the required investment from 2021 to 2029 of EUR 2.7 bn doubles this figure. However, investments will be easier to realise under a stronger GDP growth. Under the assumed GDP growth, in 2030 it will only amount to 1.1% of GDP[7]. Thus, while energy investments need to increase in absolute terms, this will in the end be compensated by an overall growth of the economy such that investment relative to GDP do not need to increase in the long term. In the short term, investments must be made more attractive through support from international donors, the introduction of a viable CO_2 price and fair investment conditions for RES. This would also include a cost-covering electricity price.

[6] Unfortunately, more disaggregated data is not currently publicly available for Ukrainian capital investment.

[7] This estimation is based on past, current and projected GDP data from the IMF's World Economic Outlook from April 2021, as well as a linear interpolation of growth after 2026 (the last year in IMF projections).

To ensure the quick build-up of more renewable energy capacity, we recommend an increase of current auction levels, combined with a so called "feed-in-premium"[8]. Additionally, further reforming the electricity market and eliminating its openness to incumbents' market power would strongly increase the predictability of returns for investors in renewable energy[9].

Finding: We can summarize that the investments needed for meeting NDC targets in the electricity sector do not outrange the investments in the past, particularly in relation to national GDP. Investments have to approx. double in absolute terms but remain constant related to GDP. Whether these investments can be raised will mainly be determined by the overall investment climate in Ukraine and the viability of underlying investors' business models.

3.4 Adequacy of price effects

Household electricity prices in Ukraine are not the result of a competitive market mechanism and represent the underlying costs of electricity generation only to some extent. Furthermore, cross-substitution between different consumer groups complicate the relation between generation costs and final consumer prices (see chapter 2). Hence, the effects of RES deployment on final consumer prices will be driven by political decisions on the design of regulated prices and supply obligations and not market dynamics.

Nevertheless, the aggregated **generation costs** of electricity have to be covered by some funding source – either through consumers and/or the state. Based on that, a comparison between actual generation costs and future costs becomes possible and will reflect potential effects on electricity prices to some extent.

The following cost components need to be considered:

- **Fuel costs**: Such as coal, uranium and natural gas and feedstock of biomass/biogas plants
- **Capital costs**: Annuity of investments depending on interest rates, generation type-specific lifetime and total investments following the JRC 2019[10] (solar rooftop and "Autoproducer" CHPs are excluded from the analysis), we assume 15% of interest rates for all investments
- **Variable and fix O&M costs**: depending on installed capacities and generated electricity, following JRC 2019[4]
- **Green tariffs**: for existing (2020) wind and solar generation capacities

Actual (2020) generation costs

For the actual generation costs only fuel costs, O&M costs and green tariffs are taken into consideration. Total annual electricity generation costs in 2020 sum up to approx. EUR 7 bn, or 59 EUR/MWh, respectively. 43% are caused by fuel costs, 46% by O&M costs and 11% by payments for green tariffs.

2030 NDC2 Policy Scenario

The aggregated generation costs are based on all investments required to fulfil the NDC2's emission reduction targets in the electricity sector. This relates mainly to the development of renewable energy sources. Furthermore, we assign investments to the retrofitting of thermal capacities for (a) meeting the NERP targets and (b) allowing for a life-time expansion of ten years. We also assume an increase of fuel prices until 2030 by approx. 50%. With an increase of renewable energy capacities and investments in lifetime expansion (10y) of TPPs, total average electricity generation costs in the **2030 NDC2 Policy Scenario** increase to 83 EUR/MWh, representing an increase of 41%. A large share also results from capital costs of 22 EUR/MWh, 27% respectively (including 5 EUR/MWh for NERP- compatible lifetime expansion of existing 7 GW of TPP).

[8] Elaborated in detail in chapter 6 of LCU's "Reaching Ukraine's energy and climate targets", May 2021, Link

[9] Elaborated in detail in chapter 4 of LCU's "Reaching Ukraine's energy and climate targets", May 2021, Link

[10] Source: JRC 2019 - Power generation technology assumptions

2030 NERP-compatible Business as usual (BAU) Scenario

To simply extrapolate today's system costs until 2030 does not consider the required investments for the life-time expansion of existing thermal generation capacities and expected developments of fuel prices. Hence, a comparison of the 2030 NDC2 Policy Scenario results and extrapolated actual costs until 2030 is inappropriate to assess the changes of costs resulting from higher RES penetration. Moreover, to meet Ukraine's international commitments, the pollution ceilings of the national emission reduction plan (NERP) need to be observed – requiring investments into ensuring that remaining TPPs meet these ceilings.

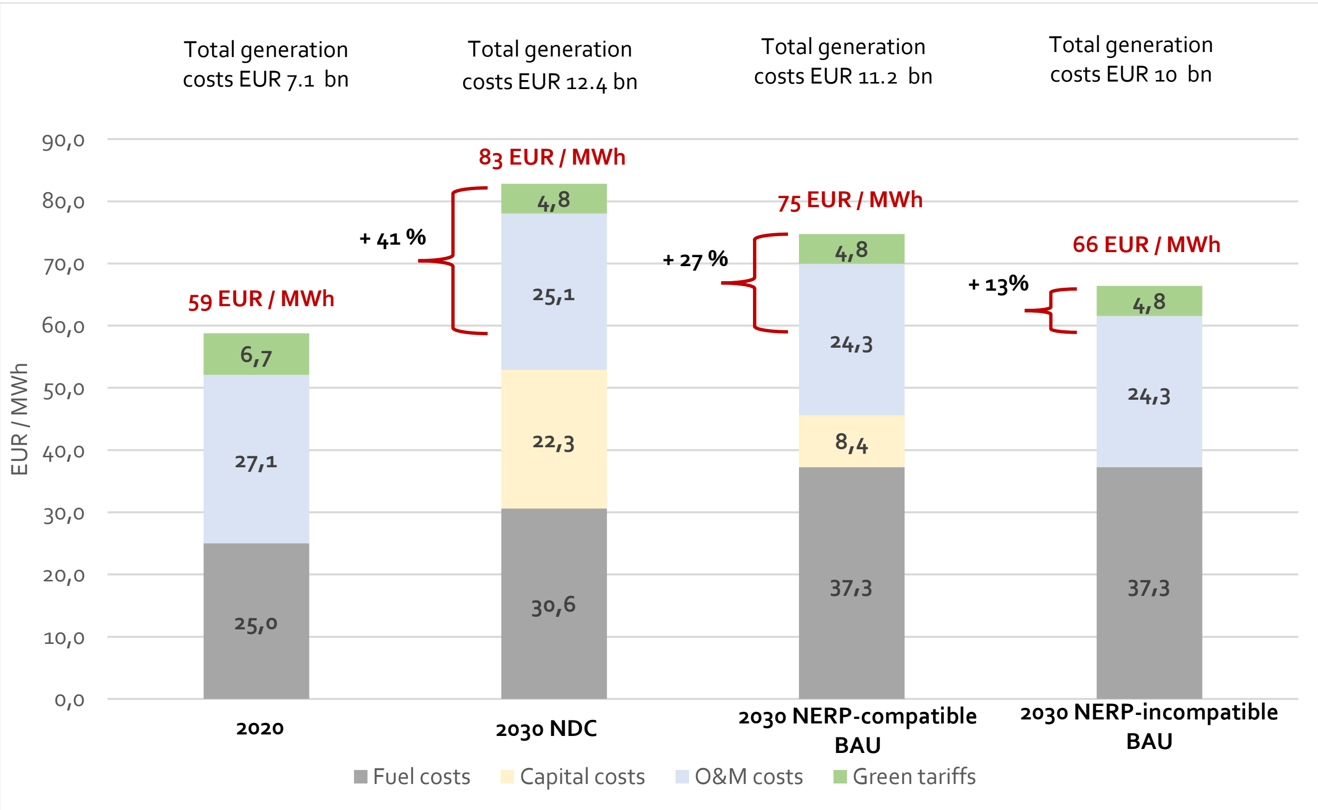
In all scenarios, average generation costs per MWh are calculated based on the net electricity consumption and not the gross generation. Thereby, losses and self-consumption are covered by the final costs. As explained in chapter 1.2, the retrofitting of existing NPP capacities is not considered in any scenario.

Assuming an extrapolation of actual electricity generation structure with a NERP-compatible lifetime expansion of 14 GW of TPPs, total system costs increase to approx. EUR 11 bn per year. Average generation costs would then be 75 EUR/MWh, 27% higher than today and only 10% lower than in the 2030 NDC2 Policy Scenario. (For a detailed summary of the calculation, please see chapter 4.)

2030 NERP-incompatible Business as usual (BAU) Scenario

We also test a scenario where Ukraine breaches its commitment to the NERP. We analyse a 2030 BAU scenario that holds today's generation structure constant but assumes an increase of fuel prices. Without a NERP-compatible lifetime extension, generation costs in the 2030 BAU scenario sum up to EUR 10 bn, or 66 EUR/MWh.

Figure 12: Average electricity generation costs (EUR/MWh), 2020, 2030 NDC and 2030 BAU



Source: Own analysis based on ODM model results

Sensitivity Analysis

Under a higher price for hard coal (20 EUR/MWh thermal input instead of the 15 EUR/MWh in the 2030 NDC2 Policy Scenario) and a moderate carbon price of 35 EUR/ton, annual electricity production costs in both the 2030 NDC2 and the NERP-compatible BAU scenario would be identical. Under these assumptions, average generation costs would exceed 93 EUR/MWh, an increase of 55% compared to 2020.

If interest rates were to reach 20% instead of 15%, total generation costs in 2030 for the NDC scenario would increase to EUR 13.3 bn (89 EUR/MWh) and for the NERP-compatible BAU scenario to EUR 11.5 bn (77 EUR/MWh). Contrary, an interest rate of just 12% would reduce total generation in the 2030 NDC scenario down to EUR 11.9 bn (79 EUR/MWh). Assuming an interest rate of only 5%, cost increases in both the NDC2 Policy scenario as well as in the 2030 NERP-compatible BAU would be equal (+ 22% compared to 2020), representing costs of 72 EUR/MWh.

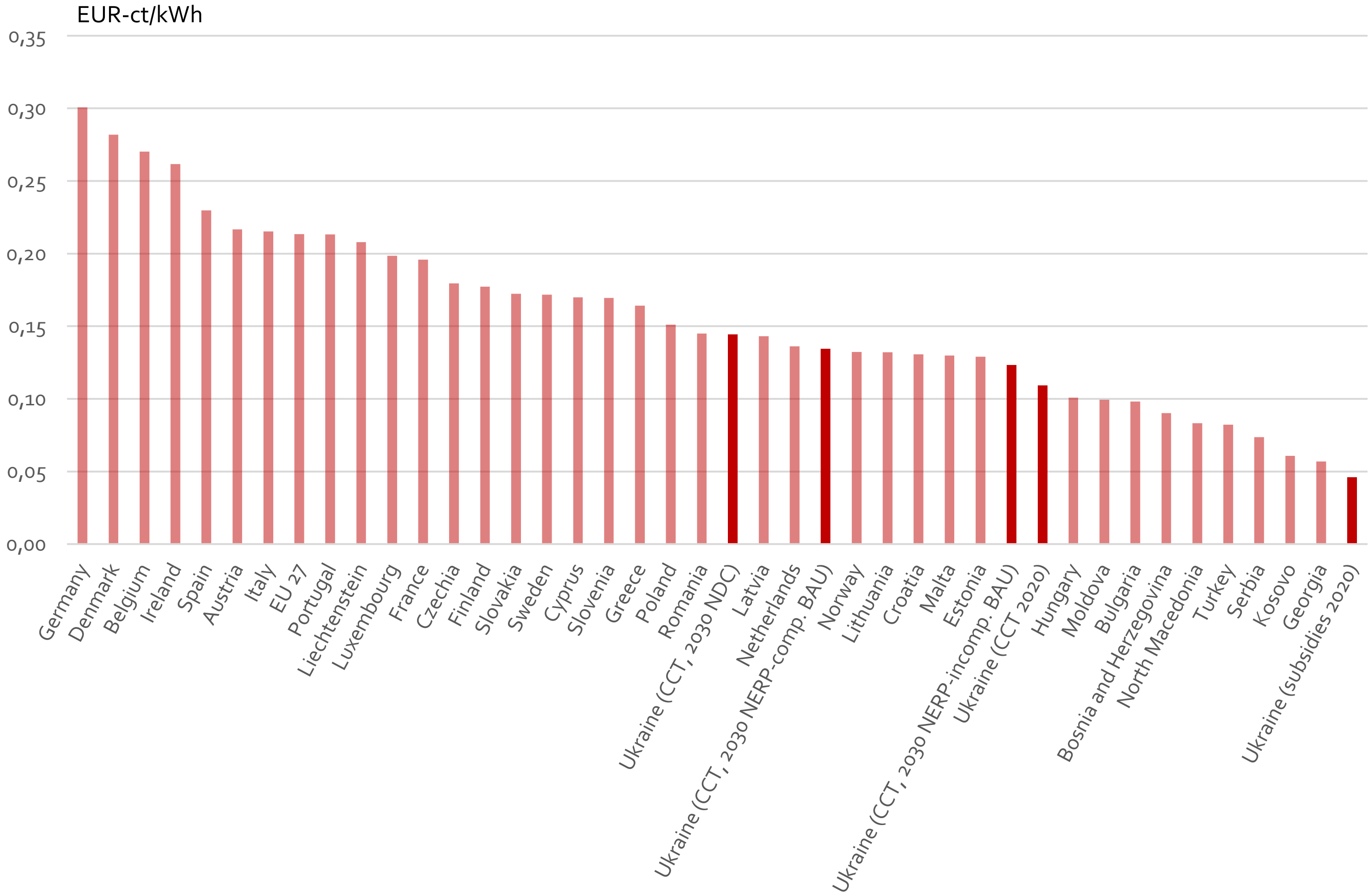
Cost-covering tariffs

As explained at the beginning of this chapter, household electricity prices in Ukraine are not the result of a competitive market mechanism. Therefore, they represent the underlying costs of electricity generation only to a limited extent. However, based on the results for electricity generation costs, we can estimate the level of cost-covering electricity tariffs. Cost-covering prices are the final electricity prices (including taxes & levies) that would have to be reached on a reformed electricity market in order to cover all generation costs through consumer tariffs. This would mean a complete phase-out of consumer subsidies. Importantly, the following estimation of cost-covering prices does not contain a proposal for how to reach cost-covering price levels. This would require a further analysis including reforms to the PSO system, wholesale electricity markets, etc.

We estimate cost-covering final household electricity tariffs for 2020, as well as for the 2030 NERP-incompatible BAU, 2030 NERP-compatible BAU and 2030 NDC scenarios, assuming that levies for transmission and dispatch, distribution and supplier margins remain constant over time and across scenarios. Cost-covering household electricity tariffs for 2020 would amount to 3,300 UAH/MWh (see Figure 4) or 11 EUR-ct/kWh, a 118% increase from current (highly subsidised) household electricity tariffs. Cost-covering household electricity tariffs for 2030 NERP-incompatible and NERP-compatible BAU scenarios are estimated at 3,700 UAH/MWh (12 EUR-ct/kWh) and 4,000 UAH/MWh (14 EUR-Ct/kWh), respectively. For the 2030 NDC scenario, we estimate cost-covering household electricity tariffs at 4,300 UAH/MWh or 14 EUR-ct/kWh, an increase by 214% from subsidised 2020 levels.

While such a price increase seems dramatic at first sight, most of the difference to current household electricity tariffs stems from the subsidy phase-out and not from additional investment costs in the NDC scenario. The saved subsidies could instead be redistributed in a well-targeted manner. Via the existing Housing and Utilities scheme, Ukraine could only support the electricity bills of those who actually need it. In fact, cost-covering 2030 NDC household tariffs are only 7% higher than cost-covering 2030 NERP-compatible BAU household tariffs. When we compare final household electricity prices under the above scenarios with other European countries, a clearer picture emerges (see Figure 13). Currently, Ukraine has by far the lowest household electricity prices across Europe. Phasing out consumer subsidies and establishing cost-covering tariffs would thus bring final electricity prices in line with comparable European countries. 2020 cost-covering household prices would mean levels similar to Ukraine's southwestern neighbour Moldova, and estimated 2030 cost-covering household prices for the NDC scenario would remain slightly below current residential consumer prices in Romania or Poland and substantially below levels of most Western European household prices or indeed the EU average.

Figure 1: Household Electricity Tariffs 2020 (all taxes & levies included)



Note: CCT = cost-covering tariffs *Source: Eurostat and own analysis based on ODM model results*

Results indicate that aggregated electricity generation costs will increase at least by approx. 27% under a NERP-compatible 2030 BAU scenario. The main driver in this case is the increase of fuel costs by approx. 50 % compared to 2020. Furthermore, a NERP-compatible retrofitting of 14 GW of the existing 22 GW of coal TPPs will contribute to another 11 percentage points of cost increase. Compared to that, a substitution of existing coal TPPs by renewable energy sources will only add another 14 percentage points of generation costs. However, the investments into new capacities with an average lifetime of 25 years will renew the age structure of the capital stock and therefore partially avoid reinvestments after 2040.

It is challenging to say whether cost increases will affect electricity prices and if so, to what extent and for which consumer group. The effect will mainly depend on the development of the market mechanism and the future structure of cross-subsidies in the electricity system of Ukraine. If Ukraine pursues an ambitious reform agenda for its electricity market and phases out household subsidies, thereby establishing cost-covering tariffs, we estimate final consumer prices to reach 11 EUR-ct/kWh today (based on 2020 data) and 14 EUR-ct/kWh in a 2030 NDC scenario. This would bring Ukrainian electricity prices in line with comparable European countries such as Moldova, Romania, or Poland. It should be noted that these figures do not yet include a price on carbon.

4 Supplementary material

Table 3: Generation cost calculation, 2020

2020							
	Installed capacity	**Generation**	**Investment**	**Fuel costs**	**Capital costs**	**Variable and fix O&M costs**	**Green tariffs**
	MW	GWh	m EUR	m EUR	m EUR	m EUR	m EUR
Thermal PP	22,000	39,505		1,197	-	713	
Nuclear PP	13,835	76,211		1,617	-	2,237	
Wind	1,000			-	-	30	
Solar (utility scale)	5,000	8,124		-	-	72	800
Biogas / Biomass	195			-	-	19	
Big Hydro & Small Hydro	5,370	5,998		-	-	130	
CHP GAS plants	4,500	14,536		187		49	
Total generation		144,375					
Losses		24,375					
Consumption		**120,000**					
Sum (m EUR)				**3,001**	**0**	**3,251**	**800**
Emission	**43**	**m ton CO2**					
Total costs	**7,051**	**m EUR**					
LCOE	**58.8**	**EUR / MWh**					

Source: Own analysis based on ODM model results

Table 4: generation cost calculation, 2030 NDC Policy Scenario

2030 NDC Policy Scenario							
	Installed capacity	**Generation**	**Investment**	**Fuel costs**	**Capital costs**	**Variable and fix O&M costs**	**Green tariffs**
	GW	GWh	m EUR	m EUR	m EUR	m EUR	m EUR
Thermal PP	7,500	25,586	3,750	1,163	747	320	
Nuclear PP	13,835	96,492		2,924		2,784	
Wind	8,200	24,851	8,579		1,327	233	
Solar (utility scale)	10,200	13,803	3,851		596	129	720
Biogas / Biomass	460	2,648	835	115	127	76	
Big Hydro & Small Hydro	4,768	8,297				131	
OCGT	1,100	1,876	480	202	73	19	
Batteries	680	-	476		95	0	
CHP BIO plants	605	2,650	1,815	28	276	8	
CHP COAL plants	1,640	4,730	164	30	33	20	
CHP GAS plants	3,730	7,062	373	127	74	43	
Total generation		187,995					
Losses		37,995					
Consumption		**150,000**					
Sum (m EUR)			**20,323**	**4,590**	**3,349**	**3,762**	**720**
Emission	**28**	**m ton CO2**					
Total costs	**12,421**	**m EUR**					
LCOE	**82.8**	**EUR / MWh**					
Increase compared to 2020	**+ 41**	**%**					

Source: Own analysis based on ODM model results

Table 5: Generation cost calculation, 2030 NERP-compatible BAU Scenario

2030 NERP-compatible BAU							
	Installed capacity	Generation	Investment	Fuel costs	Capital costs	Variable and fix O&M costs	Green tariffs
	GW	GWh	m EUR	m EUR	m EUR	m EUR	m EUR
Thermal PP	11,500	54,689	5,750	2,486	1,146	536	
Nuclear PP	13,835	97,133		2,943		2,790	
Wind	1,000	3,128				28	720
Solar (utility scale)	5,000	7,010				63	
Biogas / Biomass	195	1,126				32	
Big Hydro & Small Hydro	4,768	8,300				131	
OCGT		-					
Batteries		-					
CHP BIO plants		-					
CHP COAL & GAS plants	5,370	14,600	537	161	107	65	
Total generation		185,985					
Losses		35,985					
Consumption		**150,000**					
Sum (m EUR)			**6,287**	**5,591**	**1,253**	**3,646**	**720**
Emission	**59**	**m ton CO2**					
Total costs	**11,209**	**m EUR**					
LCOE	**74.7**	**EUR / MWh**					
Increase compared to 2020	**+ 27**	**%**					

Source: Own analysis based on ODM model results

Table 6: Generation cost calculation, 2030 NERP-incompatible BAU Scenario

2030 NERP-incompatible BAU							
	Installed capacity	Generation	Invest-ment	Fuel costs	Capital costs	Variable and fix O&M costs	Green tariffs
	MW	GWh	m EUR	m EUR	m EUR	m EUR	m EUR
Thermal PP	11,500	54,689	0	2,486		536	
Nuclear PP	13,835	97,133		2,943		2,790	
Wind	1,000	3,128		0		28	720
Solar (Utility Scale)	5,000	7,010		0		63	
Biogas / Biomass	195	1,126		0		32	
Big Hydro & Small Hydro	4,768	8,300	0	0	0 €	131	
OCGT							
Batteries							
CHP BIO plants							
CHP COAL & GAS plants	5,370	14,600	0	161	0	65	
Total generation		185,985					
Losses		35,985					
Consumption		**150,000**					
Sum (m EUR)			**0**	**5,590**	**0**	**3,646**	**720**
Emission	**59**	**m ton CO2**					
Total costs	**9,956**	**m EUR**					
LCOE	**66.38**	**EUR / MWh**					
Increase compared to 2020	**+13%**	**%**					

Source: Own analysis based on ODM model results