Working Paper

Low-carbon transition risks facing coal in Türkiye

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Abstract

Türkiye has the ambition to reach net-zero by 2053 and intermediate goals for solar and wind capacity. This analysis uses publicly available data and international models to develop scenarios to estimate transition risks to lenders to thermal power plants. The new scenarios differ from other recent net zero scenarios by making less optimistic assumptions about improved heating energy efficiency. The result is a shift in peak electricity demand from summer to winter as heating is electrified. Türkiye must rapidly implement its green hydrogen production for seasonal storage, produced using surplus summer solar power. In our scenarios thermal power plant usage will become increasingly seasonal. Such scenarios make the plants uneconomical and either cause financial stress to the power companies and their investors, or to the state through their demand for capacity payment subsidies. Other scenarios project substantial stranding of assets.

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Acronyms

BRSA/BDDK	Banking Regulatory and Supervisory Authority (of Türkiye)
CBAM	Carbon Border Adjustment Mechanism
EMRA/EPDK	Energy Market Regulatory Authority
ETS	emissions trading system
EU	European Union
EÜAŞ	Electricity Generation Company (state power company)
GCAM	Global Change Assessment Model
GW	gigawatts
GWh	gigawatt hour
LTS	Long-Term (Climate) Strategy (of Türkiye)
MENR	Ministry of Energy and Natural Resources
MW	megawatts
NDC	Nationally Determined Contributions (scenario name)
NEP	National Energy Plan
NGFS	Network for Greening the Financial System (of central banks and supervisors)
NZ	Net Zero (globally by 2050) (scenario name)
PV	photovoltaic
TCFD	Taskforce on Climate-Related Financial Disclosures
TCMB	Central Bank of the Republic of Türkiye
tCO2e	tonne of CO2 equivalent
TL	Turkish lira (as of late 2024, TL35 = $1)
TWh	terawatt hour

Executive summary

Several banks in Türkiye have publicly committed to act on climate change, even setting net-zero goals. Serious investments in renewable energy have already been made, which have put in reach intermediate national goals like 120 gigawatts (GW) of wind and solar capacity by 2035. However, Türkiye invested heavily in coal until 2010 and gas from 2000 onwards, and there is significant outstanding debt from the construction of these assets. These were financed primarily by domestic banks, with few corporate bonds issued, and this lending now accounts for 2% of bank assets. The proportion of these loans that are non-performing is four times higher (8.72%) than those of the banks' general loan portfolios.

Central banks around the world are calling on banks to better understand and manage the climate transition risks from their lending. Some of the most important risks for Turkish banks are:

- *Stranding risk*, which arises because financial returns from thermal power plants will be curtailed when those plants cease to be used, or even when they are used significantly less than anticipated.
- *Carbon pricing risk*, which will push up the cost of fossil fuel energy, eroding profit margins and further expanding the need for capacity payments.
- *EU Carbon Border Adjustment Mechanism (CBAM) risks*, which will cause energy-intensive customers to reduce their use of coal-fired power or face tariffs.

Several studies have demonstrated that the falling costs of renewables mean Türkiye can cost-effectively transition from coal to renewables and use the revenue earned from carbon taxes to compensate displaced workers in the coal supply chain.

Our study has taken a nuanced approach to modelling the practicality of switching to renewables, electrifying heat and transport, and the implications for electricity from coal. In particular, we have examined seasonal, rather than annual, demand for electrified heat and supply of renewables. This approach has revealed a more complicated impact on the demand for energy, which may require the use of seasonal storage technologies or an uneconomical, seasonal use of some thermal power plants.

We undertook seasonal modelling of supply and demand under two scenarios: Nationally Determined Contributions (NDC), which assumes Türkiye introduces no new policies, and a global Net Zero (NZ) by 2050 scenario (which sees emissions in Turkiye approaching but not quite net zero by 2050). In the NDC scenario, the advent of cheap solar means that demand for thermal power in summer is half the demand in winter from 2045. In the NZ scenario, there is actually negative demand for thermal power in summer from 2045 – meaning other sources generate so much power and so cheaply that all thermal power stations would be closed. Long before then, the load factors of thermal plants – that is, how much they are used – will have become uneconomical for much of the year. Only under the NDC scenario will load factors for thermal power rise significantly, and only in winter, due to the regularly planned decommissioning of old plants. However, a significant share of the current coal and gas fleet will not be fully depreciated by 2035.

This means that, in winter, there will be a shortfall in the amount of electricity generated, because of low solar output and high demand for electrified heat, but in summer there will be a surfeit. As well as being a transition challenge (from fossil fuels to renewables), this is also a challenge to energy security because expected returns from thermal power do not account for only limited, seasonal use. The Government of Türkiye has three broad tools to manage this:

- invest heavily in electrolysers to convert surplus renewable electricity in summer into green hydrogen that can generate electricity in winter
- maintain efforts to reduce winter demand (for example, through energy efficiency, heat pumps) and implement higher thermal efficiency standards for new buildings
- retain flexible thermal power stations (while retiring inflexible older plant) and ensure they remain commercially viable using capacity payments or other subsidies.

The first option is attractive over the year as a whole as it uses solar and wind capacity more efficiently, but it carries risks because the technologies are not yet commercially proven. Option three does not solve the issue of stranded assets (the premature decommissioning of capital items that are yet to be amortised), it merely transfers the liability from banks to the government or customer funding the capacity payment. These capacity payments have grown markedly over time and now provide an important revenue line for local coal (1.16 billion Turkish lira (TL) in 2023) and gas power (TL2.5 billion).

The implications for Türkiye's financial sector are significant. Just as banks need to expand lending to finance solar developers (and electrolysers), they also manage bad loans to the distressed thermal segment of the industry. Navigating this will require banks to interrogate power companies to ensure they have viable transition strategies to shift from uncompetitive thermal power to storage and renewables,

Minimising risks to the financial sector also requires clarity from government to ensure there exists a credible policy environment for the flourishing of green hydrogen, nuclear or any other alternatives that fill the winter shortfall identified in this research.

We examined the scheduled closure dates of gas- and coal-fired power stations to value the remaining assets at different points in the future. Around 80% of gas and 75% of current coal plants by capacity are scheduled to remain open through 2035, which is the government's target year to reach 120 GW of wind and solar. The risk of stranding is therefore imminent. However, it proved difficult to undertake the cost analysis due to balance sheet data challenges, as most balance sheets are not publicly available. This difficulty was compounded by various revaluations of balance sheets, most recently in 2023, to counter their erosion through recent hyper-inflation.

The report lays out some suggestions for the Government of Türkiye, regulators and the financial sector to account for transition risks and prepare for opportunities. These are laid out along the following lines:

A. *Better strategic direction to inform investment and withdrawal of investment*. More consistent long-term goals and intermediary targets, with an advisory body to assess their alignment with current policies, would provide assurance to the financial sector of the direction of policy. This direction should include a carbon pricing mechanism and sectoral missions to ensure viable seasonal storage options.
B. *Better risk management*. Regulators in Türkiye should set clear guidelines for risk management in banks, including scenario analysis and climate stress tests.
C. *Improved energy data and modelling*. There exists a community of climate and energy modellers in Türkiye that is ready to support the assessment of transition risks. This community would benefit from greater transparency and access to government energy models and assumptions, as well as to corporate balance sheets. A modelling forum would bring stakeholders together and encourage banks to pursue their own risk analysis.

1 Introduction

1.1 Purpose of the report

Türkiye has set a target to achieve net zero by 2053, having reached its emissions peak in 2038 (Republic of Türkiye, 2023). This transition will see far-reaching changes across the economy, leading to both growth and decline of different sectors. Türkiye's Long-Term Climate Strategy (LTS), published in November 2024, sets out its goals for different sectors and a plan for expanding renewable energy and nuclear electricity (Republic of Türkiye, 2024).

Banks, insurers and other financial institutions around the world (henceforth referred to as 'financial institutions') are being asked to consider, numerate and manage the downside risks from net-zero goals. Within Türkiye, as of 2023, banks representing more than 65% of the country's banking assets had made significant strides in aligning with global sustainability initiatives. Notably, eight banks were signatories of the UN Global Compact, five had joined the Net Zero Banking Alliance, and seven were part of the Science-Based Targets Initiative. Additionally, ten banks had committed to ceasing financing for new coal projects, signalling a clear shift towards alignment with the Paris Agreement (BRSA, 2021).

This paper illustrates risks to the Turkish financial sector from the carbon transition. Its focus is risks arising from coal-fired power, which is most affected by carbon mitigation policy, and which borrows from local financial institutions. Its purpose is to assist financial institutions and their regulators map how transition risk spreads from an industry to finance, how publicly available data and models can be used, and where data and modelling gaps need to be plugged.

Given policy and market uncertainties over the multi-decade lifespan of coal-fired power plants, our analysis uses scenarios to project different levels of electricity demand and different compositions of electricity generation.

1.2 What are transition risks?

The transition to net zero will require deep and rapid transformation of the Turkish economy. As policies are enacted to encourage that transformation, and as behaviours change linked to the transformation, there are risks in many sectors that companies will be caught out and see their revenue dry up. These are known as 'transition risks'.

The Government of Türkiye has already introduced policies to encourage zero-carbon generation, which are affecting various sectors. Transition risks can also arise from outside Türkiye. The country's trading partners are introducing policies to ensure the competitiveness of their energy-intensive manufacturing. These policies spill over into sectors adjacent to electricity generation, such as vehicles and oil refining.

Table 1 sets out some sources of transition risks, including government policy and changes in technology, consumer tastes and business models.

Table 1 Sources of transition risks

Sources	Examples
Public policy change	Energy transition policies e.g. carbon taxes, pollution control regulations, resource conservation regulations
Technological changes	Clean energy technologies, energy saving technologies, clean transportation, and other green technologies
Shifting sentiment	Changes in consumer preference for certain products; changes in investor sentiment on certain asset classes.
Disruptive business models	New ways to run businesses that can rapidly gain market shares from traditional businesses (for example, virtual/online meetings).

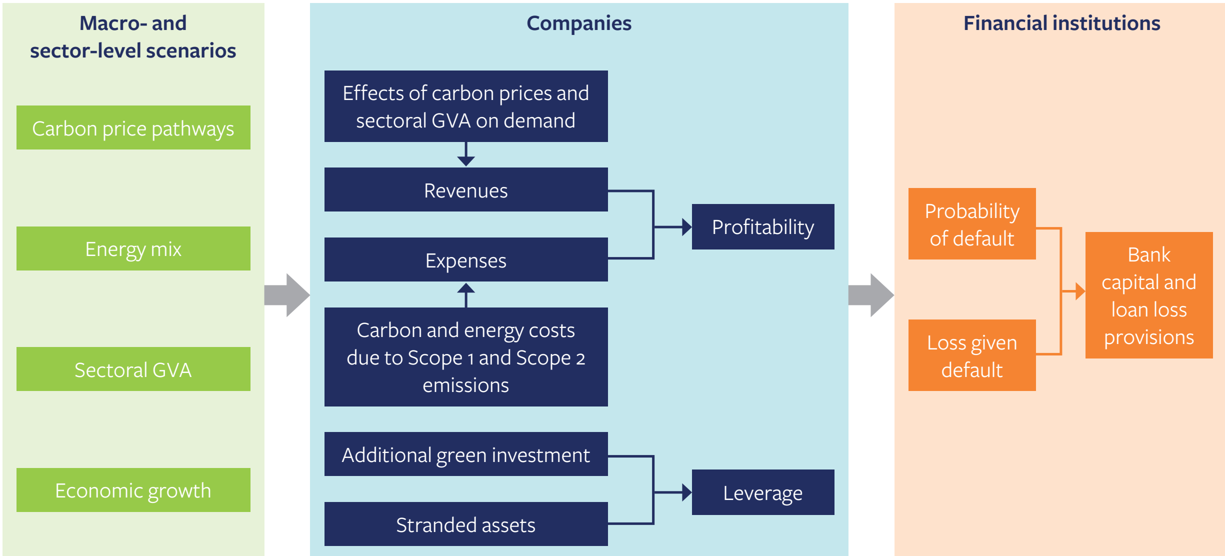
Source: Adapted from NGFS, 2020

The main transition risks to coal-fired electricity will come from policies like carbon taxes that increase the cost of power generated from coal, and from innovations that reduce the price of renewable alternatives and therefore reduce coal's competitiveness. These risks increase the chance of capital in existing coal plants being 'stranded': in other words, that the assets will not be used as much as the original investments had planned and may even have to be written off altogether. Another consequence of carbon mitigation could be risks to the macroeconomy of higher inflation, brought about by higher-cost electricity and higher interest rates.

1.3 Transition risks and financial institutions

The risks to generators will be passed on to the financial institutions that financed their construction and operation. Figure 1 shows some stylised transmission paths from the macroeconomy and the power sector to financial institutions. The energy transition will reduce energy demand overall (through energy efficiency), increase electricity at the expense of fossil fuels and the mix of fuels as more sectors are electrified, and affect the profitability of sub-sectors, both causing and caused by a collapse in coal use and expansion in renewables. This will impact specific electricity companies and firms in their supply chains. Companies typically finance asset creation by raising equity or borrowing from banks. If revenue and profits fall, they may be unable to make new purchases, service their debts or pay creditors. Financial institutions might then be exposed to the generator's stranding, insolvency or liquidity squeeze. The extent of this exposure depends on the company's leverage – how much it borrowed compared to how much shareholders have paid in.

Figure 1 From macro and sectoral variables to micro-level risks, examples of key transmission channels



Source: Dafermos and Volz, 2024

Türkiye's power sector will be affected by domestic climate policy and that of its largest trading partner: the European Union (EU). The magnitude of transition risks depends not just on policy but on Türkiye's physical climate, which influences the seasonal availability of renewable energy and the demand for electricity. The incidence of these risks within the economy depends on contractual and political-economy factors, which determine how the risks will be shared between financial institutions, taxpayers, private thermal power companies and power consumers. Three national characteristics are particularly relevant:

- seasonal electricity supply and demand and increase in intermittent electricity output
- international trade with Europe and the trading bloc's Green Deal and Carbon Border Adjustment Mechanism (CBAM) policies that respectively incentivise European industries' green transformation and protect domestic EU businesses from undercutting from carbon-intensive imports
- Türkiye's incomplete liberalisation and privatisation of the power market, which started in 2001.

Globally, banks are being asked to think strategically about these transition risks and factor them into their credit and risk management decisions. Within Türkiye, the Banking Regulation and Supervisory Agency (BRSA) and the Central Bank of the Republic of Türkiye (CBRT) supervise banks, ensuring they manage individual institutions and system financial risks. The Banks Association of Türkiye (BAT) has issued guidance for its members to adopt that reflects international best practice. To date, the guidance has been voluntary in the form of guidance documents. BRSA recently summarised the state of play in its sustainable banking strategic plan (BRSA, 2021).

Banks in Türkiye have taken steps to think about climate risks and opportunities. For instance, 6 banks (representing 36% of total assets) actively support the Taskforce on Climate-Related

Financial Disclosures (TCFD) principles (TCFD, 2017), 12 banks (representing 46% of total banking assets) have specific strategies or policies for managing climate-related financial risks, and 10 banks (representing 38% of total banking assets) have board members responsible for the management of climate risks and opportunities (BRSA, 2021). BRSA itself joined the central banks' grouping for sharing best practice on climate and biodiversity issues, the Network for Greening of the Financial System (NGFS), in 2021.

The paper is organised into the following chapters:

- Chapter 1 Explains the purpose of the report and the sources of transition risk facing financial institutions.
- Chapter 2 sets out the Türkiye context, including the current energy mix, government targets, external pressures from the EU, the financing of the power sector and a summary of recent independent analysis of transition risks in the electricity sector.
- Chapter 3 presents numerical analysis by the authors looking at the implications of these energy scenarios on coal, focusing on the stranding of assets
- Chapter 4 looks at the implications and phasing of transition risks on banks.
- Chapter 5 concludes and offers recommendations.

2 The Türkiye context

2.1 The energy mix in Türkiye

Electricity in Türkiye was generated from domestic coal and hydropower until the 1980s. Türkiye became a natural gas importer in 1987, the use of which became widespread from the 1990s – mainly for district heating. At the end of that decade, 'take-or-pay' agreements were signed with Russia for Blue Stream and Turusgas, and also with Azerbaijan and Iran, worsening the country's account deficit significantly.

This century, Türkiye has increased the share of electricity in its primary energy consumption. During the same period, Türkiye has experienced rapid economic and population growth, leading to a surge in energy demand and an increased reliance on imports. To address these challenges, Türkiye has reformed and restructured its energy system. The reforms include market deregulation, complete privatisation of power distribution and partial privatisation of electricity generation. This has been achieved through increased private and foreign investments in the energy sector.

Türkiye has diversified its energy mix in the past decade, with renewable energy growing significantly. Electricity generation from renewable sources increased by 131% between 2016 and 2021, fed by an increase in renewable energy capacity of 154% between 2015 and 2022. In 2022, the new capacity minus decommissioned capacity was 1.2 gigawatts (GW) for fossil fuels and 2.8 GW for renewables. This trend is primed to accelerate: 70% of the increase in electricity generation capacity in 2022 was from renewable energy sources (YTBS, 2022), while that capacity is projected to increase by more than 26 GW, or 53%, between 2021 and 2026.There is potential for further growth in renewable energy, particularly solar and wind, not just in electricity generation but also in hard-to-abate sectors such as the iron and steel industry, 70% of which is already electrified. Despite this progress in renewable energy, fossil fuels still account for a large share of Türkiye's primary energy supply, leading to high import dependency, especially for oil and natural gas. Existing transition scenarios project that Türkiye will need to triple its installed solar and double its installed wind capacity by 2030 to reach net zero by 2053 (Güllü et al, 2023).

In December 2022, the Ministry of Energy and Natural Resources (MENR) published a National Energy Plan (NEP). This projects that electricity generation will increase from 306.7 terawatt hours (TWh) in 2020 to 507.7 TWh in 2035. Despite this increase, the share of electricity generation from thermal power plants is expected to decline until 2035, falling to a 33% capacity utilisation rate for the thermal sources in total. However, information on how the share of coal-fired generation in total generation will reduce over the period is absent. The plan includes an additional 3.2 GW in the installed capacity of domestic coal-fired power plants by 2035, which creates further uncertainty about coal's capacity utilisation rates. The planned capacity of new coal-fired power plants has decreased by 91% since 2015. The weak economics of coal are leading to an increasing number of project cancellations in Türkiye.

In October 2024, MENR announced its new solar and wind targets for 2035, a 45% increase from the 82.5 GW in the NEP to 120 GW. This announcement excluded any adjustment to the thermal capacity. These revised goals for renewables were published in November 2024 during the climate Conference of the Parties (COP) 29. Such incompatibility has raised more concerns about how Türkiye will manage its installed thermal capacity towards and beyond 2035.

2.2 External transition pressures

Türkiye accelerated its efforts toward low-carbon development after the announcement of the European Green Deal (EGD) by the EU in 2021. In the first Turkish Nationally Determined Contribution (NDC), submitted in 2015, Türkiye only committed to reducing its emissions by 21% by 2030 relative to business-as-usual. However, with its largest trading partner poised to enact substantial policy reforms, Türkiye had to follow. A new 'National Green Deal' was announced shortly afterward, coordinated by the Ministry of Trade and other relevant ministries and official bodies, each preparing a strategic plan aligned with the wider targets (Ministry of Trade, 2021). Finally, in September 2021, Türkiye ratified the Paris Agreement and announced a net-zero target by 2053.

Further EU policies are poised to have even more monumental effects on Türkiye, chief among them the Carbon Border Adjustment Mechanism (CBAM). This is effectively a tax on imports produced with high carbon emissions. Analysis shows that, based on assumptions of €75 per tonne of CO_2 equivalent (tCO_2e), CBAM payments from Turkish exporters to the EU would reach €138 million by 2027. If the carbon price increases by 2032 to €150/tCO_2e, these costs would rise to €2.5 billion annually (Long et al, 2023).

Türkiye could mitigate these CBAM payments with its own carbon pricing scheme. If this were set at €20/tCO_2e, potential CBAM costs would decrease to €56 million annually by 2027, saving €83 million in CBAM payments. If the national carbon price was raised to €50/tCO_2e by 2032, CBAM costs would fall to €1.08 billion, representing a reduction of €1.5 billion in CBAM costs. Moreover, a carbon price implemented through a Turkish emissions trading system (ETS) would retain these charges domestically as ETS revenues, instead of paying import tariffs to the EU. Such an ETS is under consideration in Türkiye.

These carbon prices will have indirect but significant effects on fossil fuel power generation in Türkiye. Since exporters will be taxed based on the carbon intensity of the electricity used to manufacture their goods, they have an incentive to switch to renewables. This incentive applies at the national level as well. A Turkish ETS would also have a direct effect on fossil fuel power generation through existing monitoring, reporting and verification directives that cover thermal power plants (Mevzuat Bilgi Sistemi, 2014). By comparison, CBAM will not have this direct effect on electricity grids, because the interconnection between Türkiye and the EU is low.

2.3 Finance and ownership of coal-fired power plants

Türkiye commenced liberalising its electricity market in 2001. The country is highly dependent on fossil fuel imports, which peaked in 2022 at $81 billion. This far exceeds Türkiye's current account deficit, which was $45 billion in the same year.

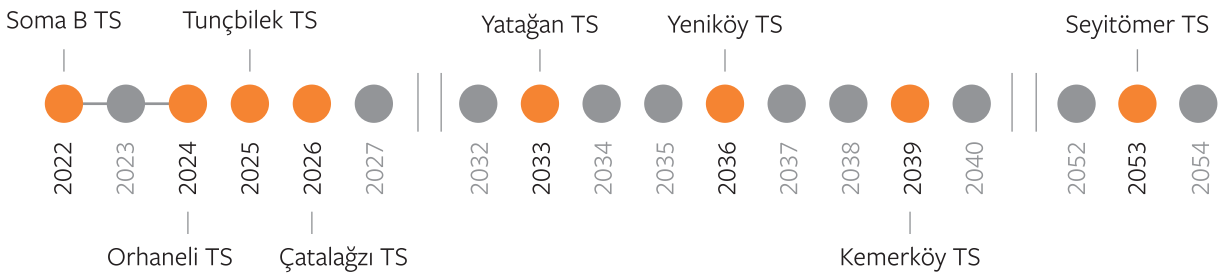
Between 2013 and 2015, the Government of Türkiye privatised nine coal power plants with a total installed capacity of 4,640 megawatts (MW), for an estimated price $8.6 billion. Loans to support the privatisation were denominated in US dollars but the income stream is in Turkish lira (TL). In the context of high depreciation of the TL, this has put huge financial pressure on coal-fired power plant owners. In 2017, the remaining debts were translated into Turkish lira to protect the plant owners against currency depreciation, and the loan payback period was also extended. Estimates suggest that only five of these plants will be able to pay back their debts to 2035 (SEFiA, 2022).

Table 2 Privatised coal-fired power plants in Türkiye

Plant name	Installed capacity (MW)	Commissioning date	Privatisation date	Privatisation value (million $)
Seyitömer	600	1973	17.06.2013	2,248
Kangal	457	1989	14.08.2013	985
Yatağan	630	1984	01.12.2014	1,091
Çatalağzı	315	1989	22.12.2014	350
Soma B	990	1953	22.06.2015	2,671
Kemerköy	653	1994	23.12.2014	521
Yeniköy	420	1986		
Tunçbilek	365	1965	22.06.2015	685.5
Orhaneli	210	1992		

Source: SEFiA, 2022

Figure 2 Break-even years for the privatised coal plants in Türkiye



Source: SEFiA, 2022

As of the end of 2022, bank loans to fossil fuel industries were 2% of total loans (TL151 billion). Of these loans, 45% were to coal-based energy production, with 45% of the loans in this area granted by private banks, 34% by public banks and 21% by foreign-owned banks. In terms of non-cash loans granted by the private banks with ESG (environmental, social and governance) risk assessment (TL58 billion, accounting for 2% of non-cash loans), transportation and refining activities related to oil and natural gas were the most prominent (47% and 25%, respectively), while coal-based energy production followed with 15%.

In 2022, the ratio of non-performing loans (NPLs) in credits provided to fossil fuels was 8.72%, significantly higher than the average NPL ratio of 2.1%. This is an important finding, as it highlights the risks that this sector poses to the financial system. In contrast, the NPL ratio for loans provided to the wind and solar energy sectors was remarkably low, at 0.6% and 0.02%, respectively, which is well below the average.

Results from a survey of banks suggest that banks are aware of the risks from lending to fossil fuel assets (BRSA, 2024). According to the report, 20 banks (with 62% share of total sector assets) take climate-related risks into account in risk management, and 12 of them (46%) have a written strategy and policy on this matter. Only five banks (23%) appear to use or reference a carbon price in managing these risks. Findings specific to fossil fuels indicate that the banking sector has a high-risk perception regarding fossil fuels. In terms of transition risks, the 'non-renewable energy' sector is ranked among the top-five riskiest sectors by 13 banks (49%). The total asset share of the five banks that consider this sector to be the highest risk is 27%.

Valuing assets in the Turkish power sector has proved difficult. Past efforts have assessed climate risks by looking at bond issuance and individual balance sheets (Goud and Tabet, 2022), but bonds make up a negligible share of power sector financing according to central bank consolidated sector balance sheets (TCMB, undated). At the same time, many balance sheets are not publicly available, making systematic, accurate analysis impossible.

2.4 Literature review of the energy transition in Türkiye

A number of studies have been published on Türkiye's possible net-zero pathway discussions, which assure the technical feasibility of the country's coal phase-out. While the studies differ on the target date, landing between 2030 and 2040, all agree that coal phase-out is inevitable in Türkiye if the 2053 target is to be achieved, and the longer the phase-out is delayed the higher the costs will be.

The report *First step in the pathway to a carbon neutral Türkiye: coal phase out 2030* (SEFiA, 2021), shows that income from a carbon pricing mechanism combined with savings from cancelling coal subsidies would finance the just transition for Türkiye's coal industry this decade. Due to their high marginal costs, imported coal plants would be the first to be phased out in the event of a carbon pricing mechanism. The study also emphasises that the coal phase-out scenario is possible even without the use of nuclear energy. In the nuclear-free coal phase-out scenario, in which the Akkuyu Nuclear Power Plant is never commissioned, the reduction in investment costs between 2022 and 2029 is $1.1 billion (ibid.) relative to the renewables-only scenario. The implication is that adding nuclear capacity increases the investment cost of a coal phase-out.

The second report, titled *Türkiye's decarbonization pathway: net zero in 2050* (IPC, 2021), analyses Türkiye's CO_2 emission pathway – for six different sectors – between 2018 and 2050 under two scenarios. It suggests that Türkiye could phase out coal from the power sector by 2035. In the net-zero scenario, coal is largely eliminated from power generation by 2035 and renewable energy capacity reaches its highest level. The scenario also assumes transitions from coal, liquid fuels and natural gas to electricity for heating. Therefore, total CO_2 emissions from all sectors in 2018 (420 million tons) would decrease to 132 million tons in 2050 (an approximately 70% reduction) instead of increasing to 690 million tons as indicated in the reference scenario (ibid.).

Further studies have reinforced these messages. Following Türkiye's first Climate Council meetings, the World Bank launched its *Country Climate and Development Report* (*CCDR*) *for Türkiye* (World Bank, 2022). This describes a resilient and net-zero development path for Türkiye, putting forward the phase-out from coal by 2040 as the key component of this path. Similarly, the SHURA Energy Transition Center's *Net zero 2053: roadmap for the Turkish electricity sector* report, published in January 2023, targets 2035 as the year for a complete phase-out of coal, with 36% of coal-based electricity phased out by 2030 (Güllü et al, 2023).

Looking at the direct and indirect benefits of phasing out coal and eventually reaching net zero, it is evident that the benefits outweigh the transition costs, especially when externalities that are mostly not monetised are taken into account. The World Bank's CCDR study calculates these costs and benefits under different sectors and time periods. The CCDR concludes that costs occur in the short term, while benefits occur mostly in the medium and long term. These benefits stem from savings from energy imports and the economic costs of air pollution on health and productivity (World Bank, 2022). The results point to the importance of taking long-term impacts and externalities into account in policy-making.

3 Demand for coal-fired electricity, load factors and early closures

This chapter examines the impact of different climate transition scenarios in Türkiye. We use these scenarios, the choice and evaluation of which are detailed in Appendix 1, to assess how the country's electricity generation might develop until 2050 and the consequences on the thermal power system in terms of the load factors of different generators (that is, the percentage of time they are active). We then consider which power stations might be forced to reduce their hours of use and face the so-called 'stranding risk'.

Two changes in particular will alter how the system operator uses thermal power stations in the future. An increased share of renewables – especially wind and solar, which are intermittent – will require more capacity and more flexibility. At the same time, the electrification of heating will lead to peak electricity demand during the winter months, precisely when solar is least efficient.

The Government of Türkiye recognises the need to prepare for more intermittent electricity generation. Its 2024–2028 Strategic Plan sets out targets for increasing the amount of electricity storage in the system: 10 GW of battery storage capacity and 5 GW of electrolysers by 2035. Additionally, demand-side participation should shift 1.7 GW of demand away from peak demand. Analysis undertaken for the German-Turkish Energy Partnership (Simou et al, 2021) considers the following options:

1. large-scale battery storage
2. small-scale battery storage
3. flexibility options for conventional power plants
4. demand-side management
5. power-to-gas
6. further operational and market design flexibility options

Battery storage lends itself to storage for 4 to 6 hours, though the current regulations allow renewable developers to install only 1-hour battery storage to be installed at a 1:1 capacity ratio. This is already incentivising the creation of large grid connected battery storage in Türkiye. Demand-side management is also geared to intra-day storage. The other options, the power-to-gas and retrofitting thermal power plants for flexibility, help manage longer-term demand and supply imbalance between summer and winter.

3.1 Extrapolating electricity generation and capacity to 2050

Appendix 1 reviews the recent efforts to model Türkiye's electricity and concludes that the NGFS scenario projections will be used to model demand trajectories, but local data will be used to project generation capacity. The approach outlined below lifts aspects from different models and integrates them into a spreadsheet tool.

When describing the results, we reflect on how this 'mix-and-match' approach might have affected them.

Box 1 Development of scenarios used in this chapter

All analysis was undertaken at five-yearly intervals between 2020 and 2050.

Total demand for electricity (TWh) between 2020 and 2050 was drawn from the NGFS 'Nationally Determined Contributions' (NDC) and 'Net Zero' (NZ) scenarios described in Appendix 1.

The growth in electricity storage and generation technologies were taken from Table 3 of Türkiye's Long-Term Strategy (LTS) for the period until 2035 (Republic of Türkiye, 2024). The recent revisions assume more ambitious deployment of solar and wind than previous strategies. The LTS does not provide projections for thermal energy plant. We have assumed that existing coal and gas power plants will be closed 40 and 30 years after their construction, respectively. We also assume that new coal and gas is built so the total matches the total generation figures from GCAM.

Beyond 2035, we assume all growth in electricity demand is met by solar and wind equally. The capacity of solar expands more because solar PV (photovoltaic) annually generates less than half the electricity per unit of capacity as wind.

The LTS includes estimates of electricity generation for the years 2024 to 2035. We instead used the NGFS numbers, which are significantly higher (compared in Appendix A). This avoids an abrupt change in generation between 2035 and 2040.

We do not project the expansion of storage technologies beyond 2035, as these are excluded from the NGFS model and in any case, do not represent a new source of generation; rather, they transfer generated electricity from times of low demand to high demand.

We note that the battery capacity projected for 2035, assuming a four-hour storage time holds at around 30 GWh of electricity. This represents around 25 minutes of the country's annual electricity consumption, making it relevant only for intra-day storage. Electrolyser capacity to make hydrogen could make a more significant impact on storage once there is surplus renewable electricity to power it.

Table 3 Summary of data used in this study's modelling and data sources

	Türkiye Long Term Strategy				NDC			NZ		
	2020	2024	2030	2035	2040	2045	2050	2040	2045	2050
Electricity generation (TWh)	*306.1*	*463.1*	*574.9*	*624.75*	*660.1*	*684.7*	*676.5*	*834.9*	*974.2*	*1064.8*
Total capacity (GW)	95.9	113.9	149.1	227.2	234.5	270.1	264.0	350.6	451.3	515.5
Hydro	30.9	32.2	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1
Wind	8.8	12.3	18.1	43.1	50.2	64.9	64.9	90.0	124.5	146.0
Solar	6.7	18.5	32.9	76.9	92.3	124.2	124.2	178.7	253.7	300.4
Geothermal and biomass energy	3	4.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Nuclear energy		2.4	4.8	7.2	7.2	7.2	7.2	7.2	9.3	11.4
Thermal power	48.9	46.9	48.1	45.6	44.6	33.6	27.4	34.6	23.6	17.4
Old coal	23.8	21.8	20.0	19.1	19.1	17.4	16.6	19.1	17.4	16.6
New coal			1.5	4.0	4.0	4.0	4.0	0.0	0.0	0.0
Old gas	25.1	25.1	22.6	16.5	15.5	6.2	0.9	15.5	6.2	0.9
New gas			4.0	6.0	6.0	6.0	6.0	0.0	0.0	0.0
Battery capacity (GW)			2.1	7.5						
Electrolyzer capacity (GW)			2	5						
Demand-side participation (GW)			0.9	1.7						

Sources:
Red text: NGFS scenarios (2024 electricity demand is NGFS's 2025 figure)
Black text: Long-Term Climate Strategy
Orange text: modelled by the team, decline in coal and gas based on planned retirement dates
Blue text: decline based on planned retirement dates, but with 2024 fixed to agree with end-2023 coal generation

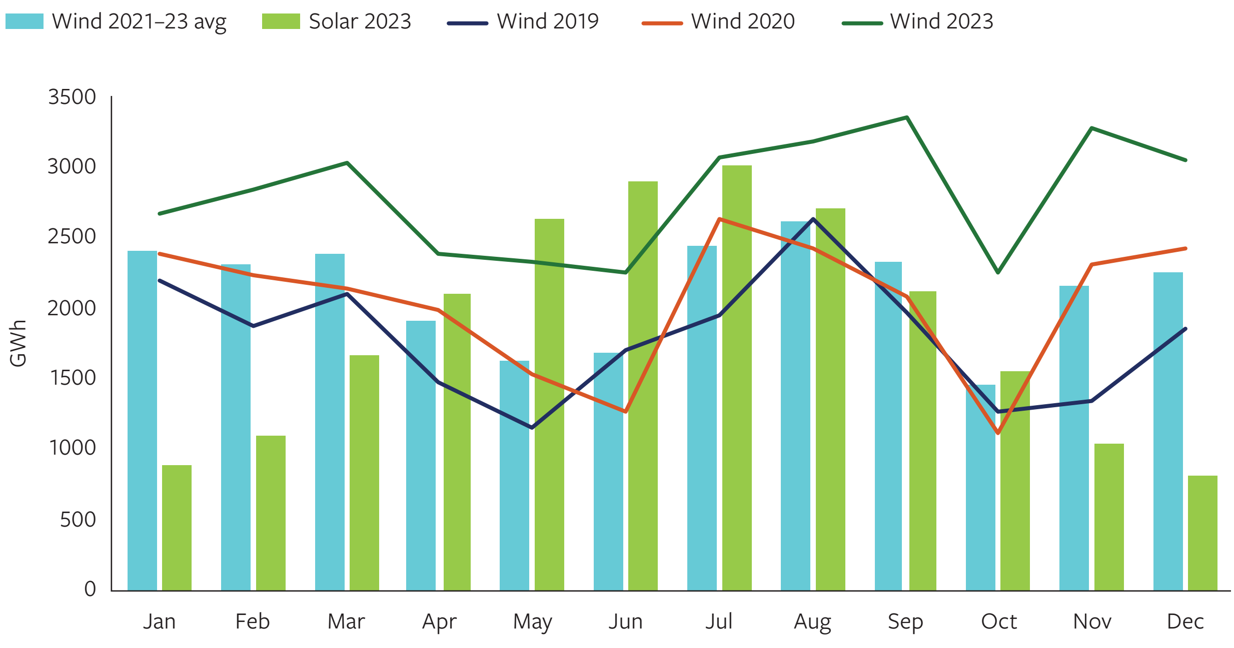
3.2 Analysis of the seasonality impacts

The NGFS scenarios lack analysis of intra-year supply and demand for electricity. As described earlier, we believe that the electrification of heat and growth of solar PV will introduce significant seasonal challenges to maintaining a balance in supply and demand.

The switch from coal and gas to hydro, solar and wind is a switch from year-round, on-demand fuels to intermittent and seasonal energy sources. Coal and gas generation, instead of being allowed to operate as baseload, will need to operate flexibly, for fewer hours a year, filling in for shortfalls when zero marginal cost hydro, solar and wind are unavailable.

Figure 3 shows the seasonality and volatility in the output of renewables arising from Türkiye's climate. Peak solar output (yellow bars) in July 2023 is four times greater than output in December. On average over 2021–23, wind varies less than solar seasonally (blue bars), producing more electricity in winter and summer and less in spring and autumn, but with a smaller difference between peak and trough months (just 80%). Averages can be misleading, however: wind generation varies significantly between years, as shown by the lines in Figure 3, which show the monthly fluctuations in wind generation in 2019, 2020 and 2023. Output swings from one month to the next. Output in October 2023, for instance, was a third lower than the previous and following months.

Figure 3 Monthly solar and wind output in Türkiye (GWh)



Source: author data from source: wind – Turkish Wind Energy Association; solar – calculated from annual solar output allocated by Enerji's monthly insolation data

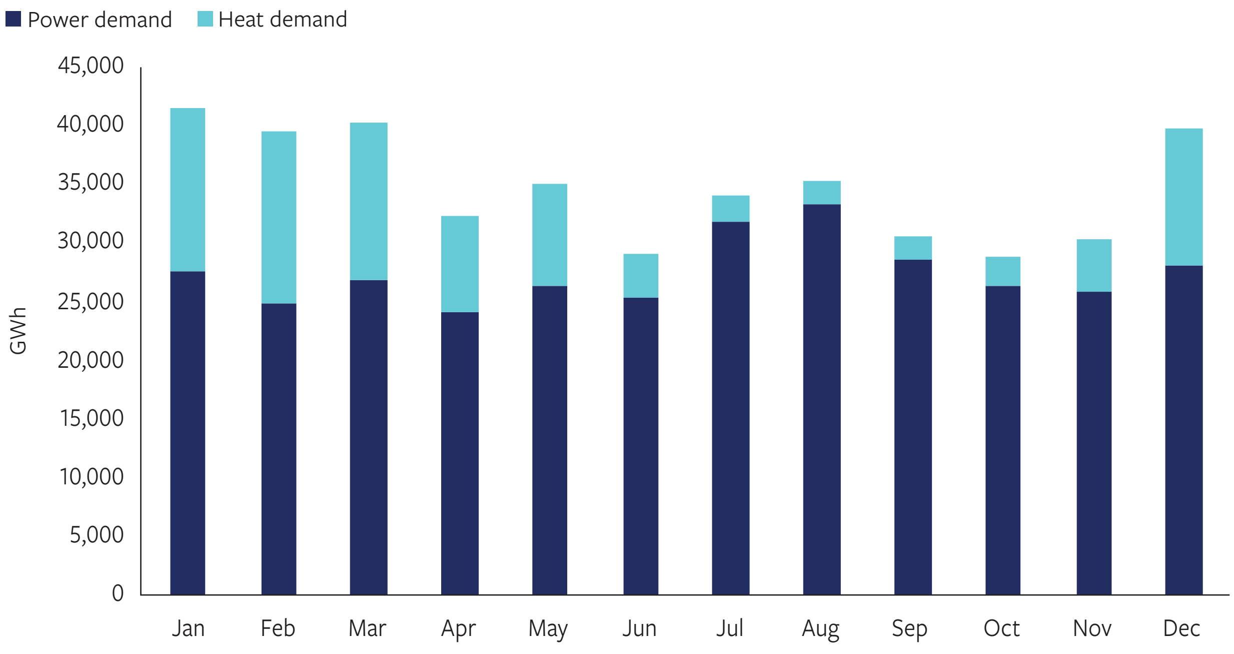
Climate change may further affect the availability or variability of renewable electricity, especially of hydropower – as changes in rainfall and evaporation will change the yield of hydropower. Government meteorologists report that temperature in 2023 was 1.2°C above the average for 1991–2020 and there have been many other such temperature anomalies since 2007 (Turkish State Meteorological Service, 2023). The effects vary across watersheds. One academic study projects a reduction of 5% in yield for the Atatürk Dam, while the Birecik and Keban Dams exhibit increases of 2.5% and 2.2%, respectively (Guzey and Onoz, 2024).

The consequence of the above discussions is that a switch to renewable electricity generation introduces seasonal pressures on capacity in winter and also less predictability of available supply necessitating backup or storage.

The electrification of heat will be a more significant change to Türkiye's electricity system than climate change variation. Figure 4 shows the demand-side impact of this shift. The analysis was based on an examination of monthly gas and power demand by sector. We converted gas to power by using consumption by the residential and commercial sector and assuming that heat pumps with an average coefficient of performance (COP) of 2.75 are deployed (SHURA, undated). This is more conservative than assumptions made by other analysts, who assume a COP of 4.7–5.1 (IPC, 2021) – which might be observed in optimal situations, but is less likely in retrofitted homes.

If residential and commercial gas heating (orange bar) switches to electricity-powered heating, the peak electricity demand (blue bar) month switches from August to January. Not only does the electrification of heat (and transport) increase demand for power, it skews it to winter when solar output is low.

Figure 4 Existing electricity demand and electrification of residential and commercial heat



Source: authors calculations, data from EPDK, 2023a: Table 8.2

Under our assumptions, the switch from gas to electricity would add 88,000 gigawatt hours (GWh) of annual electricity consumption, an increase of 26%. Most of this new demand would be concentrated in winter, however: the coldest month, February, would see an increase of 58%. At the same time, Türkiye's LTS aims to reach 120 GW of wind and solar capacity by 2035 (76.9 GW of solar PV and 43.1 GW of wind). This updated renewables goal was not accompanied by a new projection of total capacity, which therefore leaves a remaining gap of 106 GW to be filled by other sources.

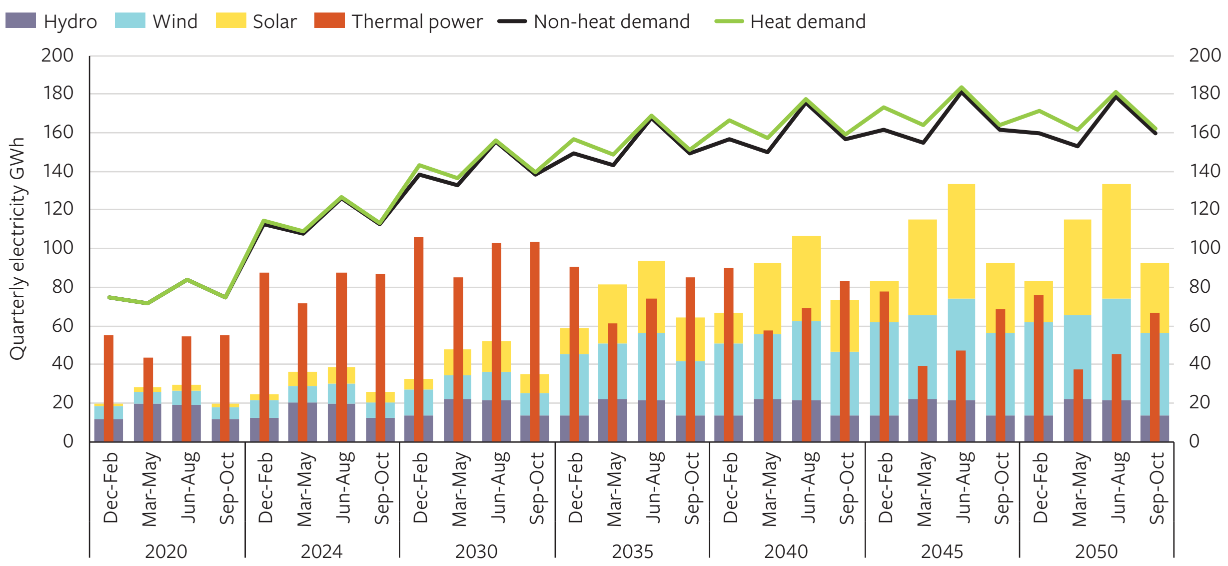
3.3 Projections of seasonal constraints for Türkiye's utilisation of power plants

We projected the seasonal output of renewable electricity (solar, wind and hydro) between 2020 and 2050 and compared this to two scenarios for electricity demand projected by NGFS. Using the seasonal pattern of heat and power use in 2023, we assumed that the split between the four seasons will be sustained in future years. We also assumed that heat demand would switch from gas to electricity but remain at 88 TWh between 2020 and 2050.

The basis for this is that the LTS's buildings' policy is focused on increasing the thermal efficiency of Türkiye's newly built residential and commercial buildings. However, these energy efficiency improvements for residential and commercial space need to be balanced by increases in floor area as incomes rise and population grows, as well as by scepticism by the authors about the ease of retrofitting existing buildings. Other researchers (Güllü et al, 2023) project lower increases in energy load from the switch to heat pumps, but the same broad seasonal pattern.

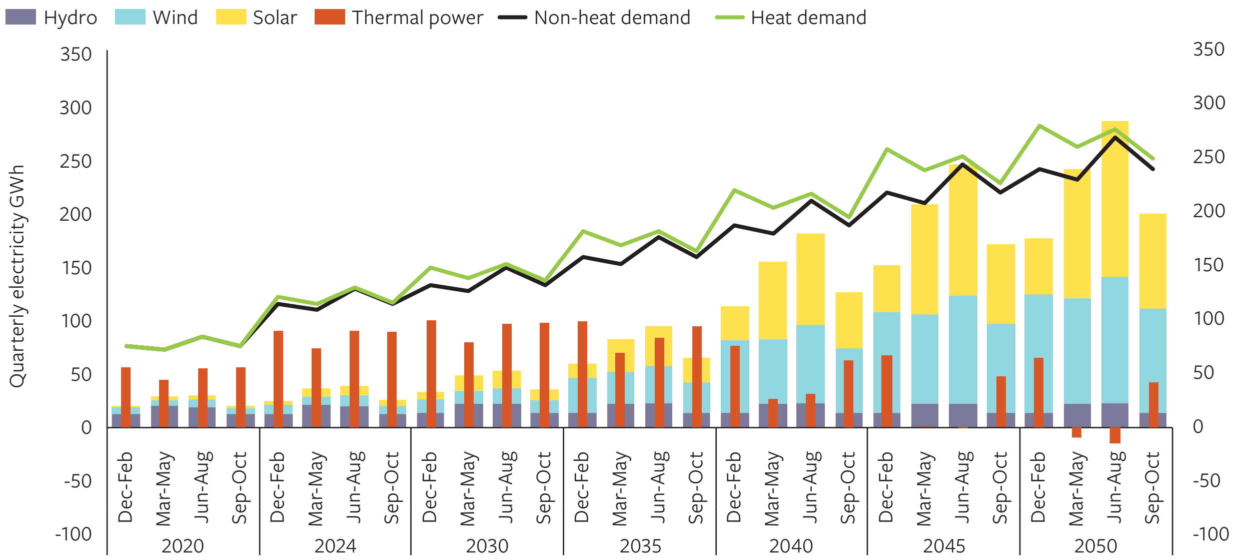
Figures 5 and 6 provide the NDC and NZ scenarios for how hydro, wind and solar (the thicker bars) change over time and across seasons. Because of the dominance of solar PV in future energy mixes, generation peaks in June, July and August. Heat demand is depicted by the difference between the red and black lines, and grows over time during the winter quarters. On the other hand, the orange bar (depicting the demand for thermal power) shows a reverse cyclical movement: so much so that for the net-zero scenario, quarterly consumption and quarterly generation of renewables exceeds demand for power in spring and summer in 2050. There is also a seasonal shift in supply in the NDC scenario, but it is less pronounced.

Figure 5 Seasonal power demand to 2050 for renewables and residual demand met by thermal power – NDC (GWh)



Source: authors' calculations

Figure 6 Seasonal power demand to 2050 for renewables and residual demand met by thermal power – NZ (GWh)



Source: authors' calculations

3.4 Load factors of different electricity generators

Table 4 shows the contribution and intensity of use of different generation technologies. Thermal technologies have an average plant loading of 45%, skewed by the high loading of imported coal plant. Natural gas has a load factor of only 30%, because it has the highest marginal cost and is scheduled for peak time usage. Lignite and hard coal, though cheap, are often located far from the centres of demand, incurring transmission constraints. Older plants may also be offline for maintenance.

Table 4 Generation and plant load factor for energy technologies, 2023

Resource Type	Installed Capacity (MW)	Generation (MWh)	Generation intensity kWh/kW/yr	Plant load factor
Hydraulic	31,962	63,854,222	1,998	23%
Wind	11,807	34,069,728	2,886	33%
Solar	13,998	18,606,601	1,329	15%
Biomass	2,080	9,706,500	4,666	53%
Geothermal	1,691	10,997,593	6,502	74%
Renewable	**61,539**	**137,234,644**	**2,230**	**25%**

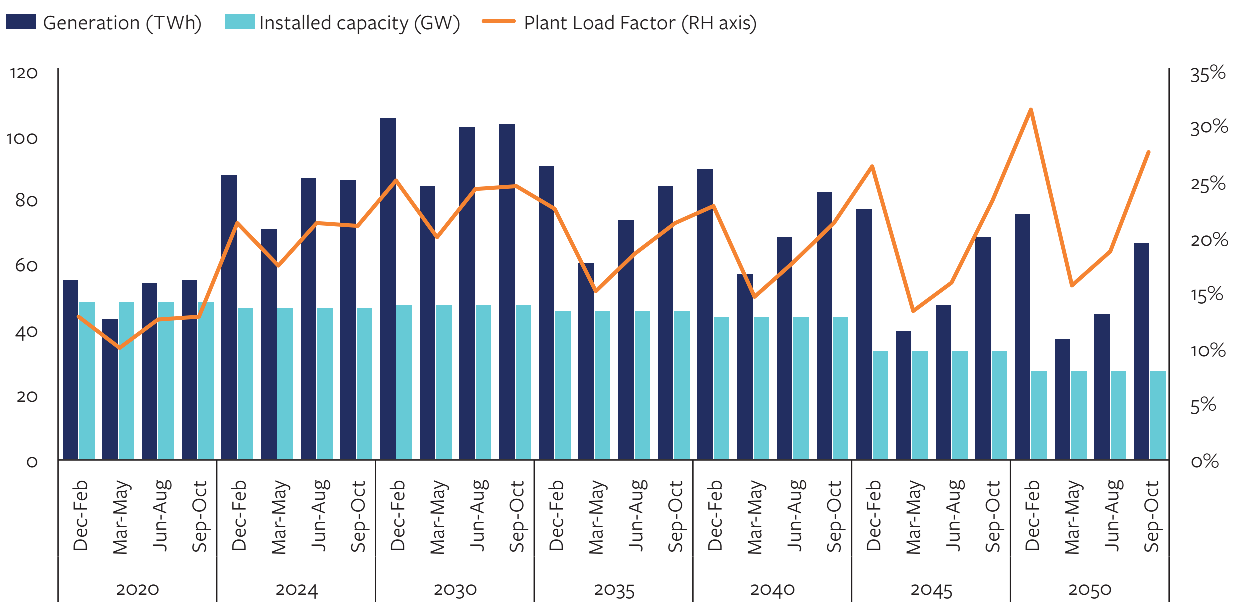
Table 4 Generation and plant load factor for energy technologies, 2023 (continued)

Resource Type	Installed Capacity (MW)	Generation (MWh)	Generation intensity kWh/kW/yr	Plant load factor
Natural gas	25,729	68,562,812	2,665	30%
Imported coal	10,374	72,123,041	6,952	79%
Lignite	10,194	40,929,632	4,015	46%
Hard coal	841	3,650,625	4,342	50%
Asphaltite	405	1,588,317	3,922	45%
Fuel oil	260	702,474	2,700	31%
Naphtha	5	–	–	0%
LNG	2	–	–	0%
Diesel	1	2,307	2,218	25%
Thermal	**47,810**	**187,559,208**	**3,923**	**45%**
Total	**109,349**	**324,793,851**	**2,970**	**34%**

Source: EPDK, 2023b

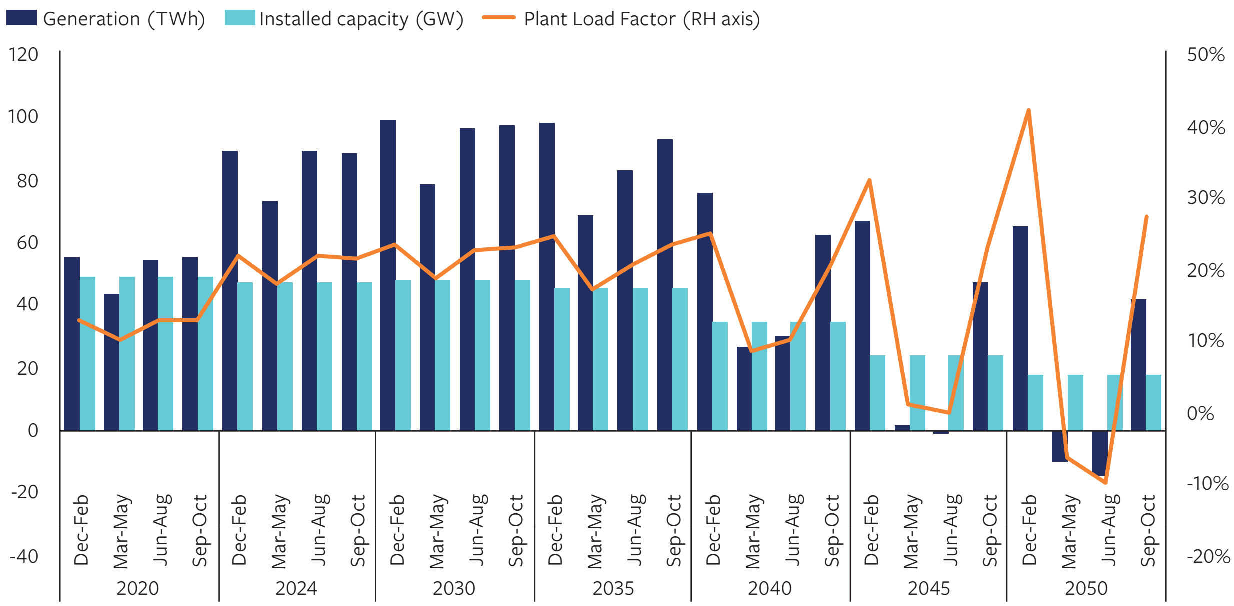
Our modelling based on NGFS suggests that in both scenarios, the plant load factors for dispatchable power (thermal generation and seasonal storage) needed to complement renewable energy swings massively from season to season. In the NDC scenario, winter demand is double that of summer by the 2040s. In the NZ scenario, the swings for dispatchable supply between summer and winter are even more pronounced. Winter demand in the 2040s is double average current demand, but in summer there is surplus supply, meaning renewable power would need to be curtailed.

Figure 7 Quarterly generation and plant load factors for Türkiye's thermal power plants, NDC scenario



Source: authors' calculations

Figure 8 Quarterly generation and plant load factors for Türkiye's thermal power plants, NZ scenario



Source: authors' calculations

3.5 Implications for Türkiye's energy mix

These changes pose a challenge for the design of Türkiye's future energy mix. For intermittent renewables to account for winter demand would require massive over-capacity coupled with significant short-term storage, since solar panels operate at ~70% less than maximum efficiency during the winter months. A more likely solution is the maintenance of more reliable electricity generation, through a combination of hydropower, fossil fuels and hydrogen from electrolysers to bolster renewables when needed.

Hydrogen from electrolysers offers a possible solution. Power demand during the summer months, when solar is plentiful, will be met easily by existing renewable energy targets. Indeed, the efficiency of solar presents an opportunity to use electrolysers (1.9 GW of which capacity is mentioned in the LTS and 70 GW in 2053) for the creation of green hydrogen near solar plants to be stored for later use. This can be integrated into the gas network using existing gas pipeline infrastructure, burnt as a fuel in suitably modified gas power plant or used in fuel cells in local district heating systems. However, green hydrogen is a fledgling technology and production costs are high. To date, the largest electrolysers are 10 MW; they will need to be an order of magnitude or two larger to reduce the unit costs of commercial green hydrogen (ISPT, 2022) so it can contribute.

Without significant renewable over-capacity or large-scale electrolysers, fossil fuel generation may be needed to pick up the slack during the winter months. However, this will mean the seasonal use of different generators, and therefore lower load factors all round. The economics of fossil fuel generation will suffer from the increase in share of intermittent generation, because the system operator will only schedule coal and gas to operate in times of low renewable load.

This increases the risk of stranding – fossil fuel assets built under the expectation of decades of continuous use will be inactive for most of the year. In other words, existing fossil plants will be used so little that they may struggle to pay their capital charges.

4 Financial impacts of energy transition on lenders

The previous chapters show that in many of the energy mix scenarios, thermal power companies face at least some degree of risk. But these risks go beyond the generators: they permeate the economy and especially the financial sector that supplies capital to finance power plant construction and privatisation purchase.

One channel for these risks will be the rapid uptake of renewable power generation. This is likely for three reasons: it is necessary to reach Türkiye's NDC targets, it makes sense because renewables are cheap and do not depend on imported fuels, and the government has set targets to achieve this uptake. Cheaper, more efficient power generation will be called on at the expense of thermal power plants, reducing the utilisation rates of the fossil fuel generators and stranding their assets.

This stranding may be somewhat mitigated by the complications discussed in chapter 3: the rapid electrification of heat may cause electricity demand to outpace the advance of renewables and clean seasonal storage, meaning that reliable fossil fuel generators must be called on. This will likely not solve the issue, however, as it is possible that electrolyser technology and assets will be rolled out sufficiently quickly to meet that winter demand. It is also possible that the electrification of heat will be slower than anticipated, which would delay the peak demand switch from summer to winter. More to the point, even if fossil fuel generators are called on, it will not be in a scenario that makes economic sense. No company that built or bought coal or gas-fired power plants will have expected them to be used only three months of the year, and perhaps even then only at low utilisation rates for flexibility around the availability of renewables.

Policy-makers are conscious of the need to maintain the financial viability of power plants and storage that will complement intermittent renewables. To remedy this issue, they introduced capacity mechanisms in 2018 to maintain security of supply (and meet the July peak demand), prioritise domestic resources and ensure gas is rewarded. In 2019, the criteria changed, adding smaller hydro and setting minimum efficiency criteria for plant using imported fuel. In an evaluation by staff from the regulator (Korucan and Yardimci, 2023), the researchers interviewed industry participants and experts. Complaints centred around the distribution of payments (plant relying on imported gas received a high share of the fixed budget, contrary to the law's objectives), but the industry did not wish to give up the capacity payments despite its flaws.

The thermal sector already relies on these capacity payments to maintain viability. Capacity payments in 2023 were TL4 billion, of which TL2.5 billion were paid to gas generators and TL1.16 billion to domestic coal. As thermal plants are used less and less, they will either become stranded assets (passing transition risks to lenders and investors) or will depend on evermore generous capacity payments. The rules governing eligibility to the capacity mechanism will determine the rewards for coal and gas and competing government priorities to reward domestic energy sources versus efficient plant versus most flexible plant. If the government sets capacity payments according to the usefulness to the system operator in matching supply and demand arising from the earlier discussion, it would pay a premium for more flexible plants. If the government were minded to displace foreign imported fuels, it may also tilt capacity payments to domestic coal and hydro. There is also a political risk to private investors and lenders that future governments will countenance increased transfers. In any case, capacity payments do not *resolve* the issue of stranding. Someone will be left paying to keep these generators partially active: either investors and banks whose loans face risk, or the government and consumers through higher bills. The authors note that other countries that use such mechanisms have sometimes set it as a capacity auction and opened it up to demand-side players that reduce peak load.

We note a capacity auction could in theory also be opened up (at a higher rate) for new technologies like green hydrogen/electrolysers, or other storage technologies.

There are other risks to fossil fuel assets beyond their displacement by renewable energy. One of the most important is the EU's CBAM policy. The EU is Türkiye's largest trading partner and is implementing a border tariff on goods produced with high embodied carbon. It is currently restricted to steel, aluminium, cement, fertilisers and hydrogen, but the aim is by 2030 to cover all goods within the scope of the EU-ETS (Benson et al, 2023). There are broadly three possible outcomes for Türkiye from this policy that lenders to the power sector need to consider:

1. Türkiye introduces its own emissions trading system (ETS) with carbon prices similar to the EU-ETS price. This would stop the EU levying CBAM according to the EU's rules and imposing an internal tax on carbon, allowing Türkiye to retain the levy revenue. This would put further pressure on thermal generators and their financers, and encourage a more rapid switch to renewables.
2. Producers of goods likely to be impacted by CBAM may choose to generate their own green electricity by building unlicensed or captive renewable plants. This would avoid exposure to the grid's high carbon intensity and therefore limit the CBAM tariffs they face for exports to the EU. The consequence would be reduced electricity demand from the grid and the same threat of stranding for power generation from high carbon intensity assets.
3. Without either of the above responses, Turkish exporters will face the CBAM tariffs, making them less competitive and therefore limiting exports. Lower production would reduce demand on the grid. Alternatively, exporters could be subsidised to the value of CBAM tariffs, which would pass on the costs to the Turkish Government.

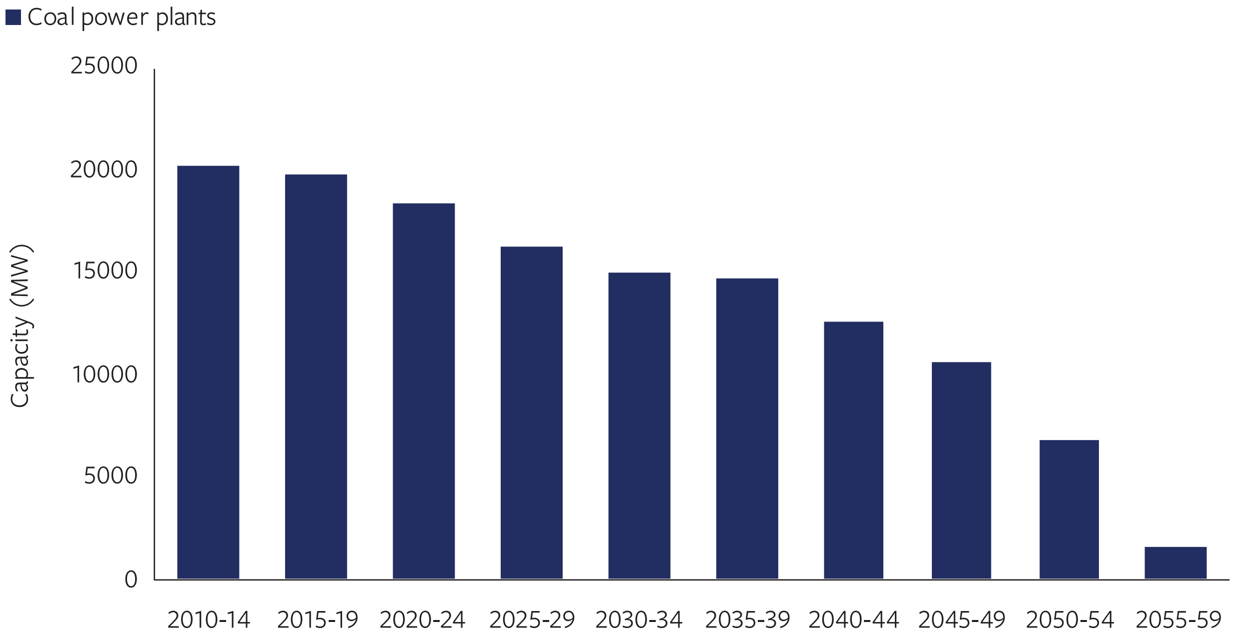
All of these outcomes are likely to reduce the financial viability of thermal power stations, reducing their ability to service loans, unless the state shoulders the cost through capacity mechanisms and other subsidies.

4.1 Value of Türkiye's existing coal and gas plants

What kind of financial losses might lenders to the power industry make if assets have to be written off prematurely? The value of the remaining plants on the power company's balance sheet depends on the capacity of plants they own, their remaining years of economic life and the plants' cost when they were first acquired. Many of the older power plants were constructed by EÜAŞ (Electricity Generation Company, the state power company) and then subsequently privatised as described in Chapter 2.

As of July 2024, Türkiye has a total of 78 coal-fired power plants. Of these plants, 22 were built before 1990, 9 in the 1990s and 47 in the following decade. Given that the operating life is 40 years, 50 existing plants are scheduled for closure by 2050, with the remaining plants to be closed by 2062.

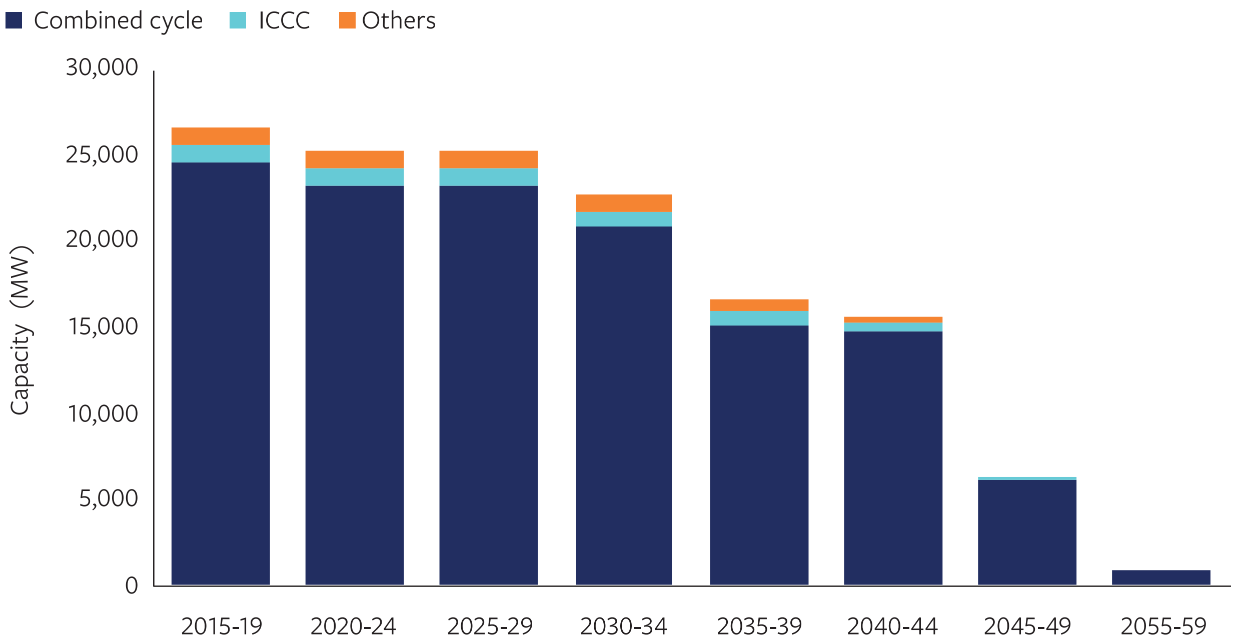
Figure 9 Scheduled volume of closure of Türkiye's coal power plants (according to capacity, megawatts (MW)) by five-year bands and average remaining life



Source: Global Coal Plant Tracker, 2024

Türkiye also has 88 existing gas and oil-fired power plants. Of these, 10 were built in the 1990s and 24 in the following decade. Given that the operating life is just 30 years, all but one of the existing plants is scheduled for closure by 2050 (the Kırkareli plant is scheduled to open in 2025).

Figure 10 Scheduled volume of closure of Türkiye's gas plants by five-year bands and average remaining life (according to capacity, MW)



Source: Global Oil and Gas Plant Tracker, 2024

NB (ICCC = internal combustion combined cycle)

The balance sheet value of a plant falls over time as the fixed assets depreciate. A young fleet of stations will typically be more valuable than an older fleet, which has already been partially written down. As suggested by Figures 9 and 10, even though most plants will likely be closed by 2050, significant capacity will remain open over the next 20 years unless they are decommissioned prematurely.

Most of Türkiye's thermal generation companies are not publicly owned, and balance sheet data is hard to come by. However, from the central bank consolidated balance sheet for the power sector – covering generation, distribution and supply – it is clear that bank loans are the main source of finance, covering more than 90% of the financial liabilities (TL1.07 trillion, $30 billion). By comparison, bond issues are negligible (TCMB, undated).

Recent episodes of high inflation complicate the situation in Türkiye. Their initial effect was to wipe out the real balance sheet valuation of fixed assets, rendering the stranding risk negligible. However, the Treasury has instructed companies to move to inflation accounting, adjusting their 2023 balance sheets in line with inflation (Reuters, 2023). This may reverse the effect of inflation, rekindling the risks of stranded assets as these regain value.

To complicate matters further still, it appears that there have already been significant revaluations. The same sectoral balance sheet from the Central Bank of the Republic of Türkiye (TCMB) shows TL615 billion of shareholder equity, of which TL400 billion comprises 'revaluation of tangible fixed assets', which occurred between 2021 and 2023 before the Treasury-mandated shift to inflation accounting (TCMB, undated). It is beyond the scope of this report to comprehensively evaluate the value at risk, and at this point in time it is difficult to assess the value of outstanding debts held by the generators for their tangible assets. Nonetheless, the general implications of these revaluations are clear: they will already have reversed the devaluation of fixed thermal power assets to some degree, increasing the value that is vulnerable to stranding and therefore bringing back the risk of stranded assets.

For context, the consolidated income statement for the industry puts the gross profits for the sector at TL265 billion, after subtracting the costs of fuel and sales within the industry (suppliers buying power from generators). Meanwhile, the cost of financing the sector's existing debt is put at TL176 billion, which further eats away at profits. The result was only TL22.6 billion for profits before extraordinary items in 2023. The claim by thermal power stations that capacity payments (TL4 billion in 2023) are essential to profitability are therefore quite credible.

5 Conclusion and recommendations

Türkiye has set itself ambitious goals to achieve net zero by 2053, which will require substantial changes in electricity generation, heating, transport and industrial energy use. Achieving even parts of those goals is a major financing challenge, given the level of investment needed in transmission and storage and the risk of stranding of electricity generators. As we discussed earlier, the coal and gas fleet, in particular, being relatively young, is exposed to losses through stranding – that is, the premature decommissioning of capital items that are yet to be amortised.

The transition risks may manifest through rapid deployment of renewable energy – whether because they become even more competitively priced or in adjusting to government targets – or through external pressures like the EU's CBAM. Projecting these risks is complicated by Türkiye's prospective electrification of heat. If this is achieved rapidly, as it must be to meet the 2053 targets, it will considerably increase electricity demand during the winter, causing a new peak demand at a time when solar PV is least efficient. Analysing the value of the coal and gas fleets, and therefore their exposure to transition risks, is further complicated by repeated bouts of inflation over the lifetimes of the existing plants and different revaluations more recently.

Nonetheless, under all of the scenarios considered in this paper, the transition risks to thermal generation are high. This leaves generators, banks and the public sector exposed to stranded assets unless expensive subsidies are deployed to protect them. Such protection would use scarce resources to maintain the viability of technologies we seek to transition away from. The functional value of the thermal power stations in terms of them supplying flexible generation that can ramp up in winter will be undercut by long-term seasonal storage technologies like green hydrogen produced using electrolysers, further expansion of hydropower, and/or interconnections with countries further south that have surplus winter electricity and deficits in summer because of high air-conditioning loads.

5.1 Recommendations

The recommendations below to government, regulators and the financial sector seek to better prepare Türkiye's banks for the transition risks and opportunities. They are important, since banks are responsible for nearly all debt capital supplied to the electricity sector. The recommendations are organised into three clusters:

A. better strategic direction to inform investment and withdrawal of investment
B. better risk management
C. improved energy data and modelling

A. **The Government of Türkiye should issue strategic direction to inform investment and withdrawal of investment.** Banks need a clearer plan of all the technologies that the government sees as a priority for investment and the policy environment to bring about their development. It should identify sectors and technologies that need to be scaled back and a just transition plan to protect impacted communities. The government should:

1. *Publicly release longer-term energy plans*. Investments in the energy sector often have time horizons spanning many decades. It would be helpful for lenders to have long-term (up until 2053) and coherent information upon which to base their decisions. The government should publish and update figures for energy demand, generation and storage technology from a suitable energy model, ideally with breakdown of demand by season.

2. *Create an advisory body to assess the adequacy of existing policies to meet goals*. This should also assess whether the mid-term targets are aligned with the long-term net-zero strategy.

3. *Prepare a programme, timetable and funding arrangements for the orderly closure of inefficient or outmoded technologies*. Balancing climate and social priorities requires careful political handling. Domestic mining jobs will be affected. Careful planning and coordination with communities is needed to ensure sufficient retraining and other opportunities are available for workers. This can help increase the credibility of the plan and provides greater comfort to lenders that they will be seen through.

4. *Publish carbon pricing plans*. Plans for Türkiye's planned emissions trading scheme should be published soon and should include indicative prices for carbon so energy-intensive industries can avoid worthless investments to mitigate CBAM risks.

5. *Adopt explicit missions to develop key technologies*. Key technologies like commercial green hydrogen production need to be scaled up. This paper has stressed the need for additional electrolysers to create green hydrogen during the summer months, when there is ample solar generation, to be stored for use in winter. The government should adopt a mission-based approach, working with academia and industry to understand and unlock constraints. Policy support, for instance, an electrolyser capacity auction, will be needed to subsidise first generation electrolysers and the use of green hydrogen – either for electricity generation or blending with residential gas ahead of market need.

B. **Regulators should mandate better risk management.** TCMB and BRSA should develop a work stream to lead banks and their counterparties to better disclose and manage their transition risks and opportunities, ultimately undertaking climate stress tests using scenarios analysis. They should:

   1. *Announce clear expectations for banks on climate risk management.* TCMB and BRSA have already published extensively on climate risks. They should also now set out clear expectations of what is expected from banks, including scenario analysis and climate stress tests, and the timescale over which action is required.

   2. *Convene a climate working group.* TCMB and BRSA should convene a group for banks to prepare for climate transition and to provide feedback to regulators on how to better implement TCFD disclosures and climate stress tests. TCMB might ask volunteer banks to trial disclosure and scenario analysis ahead of other banks.

C. **Improved energy data and modelling.** Türkiye has a community of academics and energy modellers that could assist the efforts of financial institutions to understand transition risks. This could be done through:

   1. *The government releasing its energy model to interested parties.* The government operates an energy model that was used to develop the National Energy Plan. This should either be released or detailed results shared with the financial community and independent energy modellers.

   2. *Corporate disclosure of balance sheets.* Better corporate-level data on (power) company's balance sheets is needed to provide visibility of energy companies' leverage and of borrowing from other entities.

   3. *The government establishing a modelling forum.* This would help government and other energy analysts to enhance projections and compare results from different models. TCMB and BRSA may wish to augment the model to introduce investment data, which is missing from most energy models but important for analysing climate risks.

   3. *Financial institutions analysing their climate risks.* Banks should use existing electricity models and scenario analysis in the near term, moving to regulator supplied scenarios later. This paper has made use of NGFS scenarios under the Global Change Assessment Model (GCAM; see Appendix 1), which may be particularly useful for international comparisons given their global reach. However, this paper has also shown that the GCAM scenarios should not be used alone, without additional adjustment to align them with realities in Türkiye.

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Appendix 1 Comparing transition scenarios for Türkiye

International and domestic models and NGFS's scenarios

Central banks are mandated to ensure that financial institutions maintain adequate reserves to ensure solvency and liquidity under plausible financial shocks (micro-prudential regulation), and that the financial system as a whole can withstand economic shocks (macro-prudential stability). Since the 2008 global financial crisis, central banks have asked financial institutions to simulate economic and financial shocks on their loan portfolios – so-called 'stress tests'.

A working group of central banks within the Network for Greening the Financial System (NGFS) has laid out a set of scenarios to help estimate potential climate risks over the long term, with guidance on how to conduct climate stress tests (NGFS, 2021). The guidance seeks to support central bankers to assess whether current lending practices are exposing financial institutions to excessive risks from greenhouse emission mitigation measures (that is, transition risks) and physical damage to economic assets (that is, physical risks).

As the first global effort of its kind, the NGFS tool has many advantages over other methods of estimating climate risk. The models that create the projections are often either more sophisticated than local versions or project their scenarios to longer time horizons, which is a key feature to understand the full delayed effects of climate change. The standardised scenarios and assumptions underpinning the models also enable high-level comparisons between those who use them, both internationally and domestically. The models cover all territories and can therefore incorporate international and macroeconomic effects, for instance, trade in carbon-intensive goods, global carbon prices and sharing of environmental goals between nations. On the other hand, the global assumptions of the NGFS scenarios and models necessarily lack the level of detail that can be achieved using models with narrower scope. This is especially true for modelling subnational climate risks and impact. Some of the scenarios may also cause confusion when used at the national level: for example, the NGFS Net Zero (NZ) scenario imagines the global achievement of net zero by 2050, but this projects some countries as carbon sinks by that date, while others maintain a certain level of emissions.

This appendix explores some of these NGFS projections and their plausibility as reflections of future paths for Türkiye, to evaluate their potential use by Turkish financial institutions in their risk modelling.

The projections were built with the NGFS scenario explorer, using the Global Change Assessment Model (GCAM) Integrated Assessment Model (JGCI, 2021). The discussion covers only two of the seven available NGFS scenarios, following consultation with Turkish industry experts:

- **Nationally Determined Contributions (NDCs).** This global scenario reflects the extrapolation of global pledges as made in NDCs in 2021, resulting in only limited CO_2 reduction, global warming of 2.6ºC by 2050, and therefore high physical risks and lower transition risks. For Türkiye, this implies roughly constant CO_2 emissions, peaking in 2035 but remaining equal in 2050 to 2020 (roughly 355 Mt CO_2e). The scenario will likely change with the next round of updates to NDCs in 2025.
- **Net Zero by 2050 (NZ).** This global scenario keeps warming below 1.5ºC by assuming that ambitious policies are implemented immediately worldwide, leading to rapid transition. This therefore implies low physical risks and moderate to high transition risks. It assumes differentiated responsibility, with Türkiye's CO_2 emissions projected to drop to 49 Mt CO_2 per year by 2050, balanced by advanced economies reaching net zero earlier and also implementing carbon sequestration at scale. This scenario implies a roughly similar transition to Türkiye's stated net zero by 2053 ambition.

These scenarios are compared against projections of electricity generation performed by various Turkish and international organisations, to gauge their plausibility. These are:

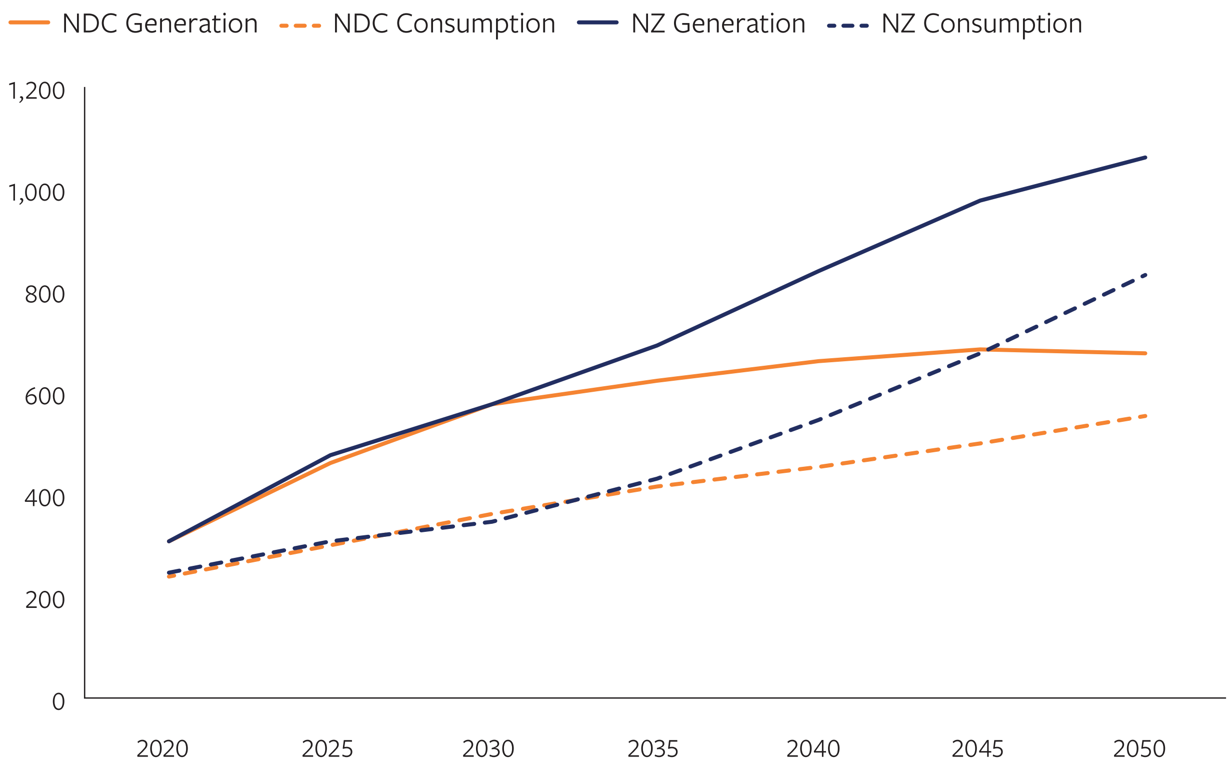
- **Istanbul Policy Centre (IPC) Base and Net Zero scenarios.** The IPC set out a roadmap to 2050 that it has periodically updated (Şahin et al, 2021; Teimourzadeh et al, 2023); the next version will be released in 2025. The roadmap is based on an energy model by EPRA Energy, which is commercially available.
- **SHURA Energy Transition Centre Net Zero scenario.** In 2023, SHURA released a roadmap for the Turkish electricity sector to 2053. This is based on E3M's energy model. The roadmap includes a net-zero scenario (Güllü et al, 2023).
- **National Electricity Plan (NEP).** The National Electricity Plan was released in 2022 by the Ministry of Energy and Natural Resources. It uses the Türkiye Energy Model, which is not publicly available.
- **Long-Term Climate Strategy (LTS).** Published to the UN Framework Convention on Climate Change (UNFCCC) in October 2024, this country strategy was developed under the leadership of the Ministry of Environment, Urbanization and Climate Change, and the Presidency of Strategy and Budget. It includes updated renewable energy capacity targets for 2035, of 120 GW of combined solar and wind, but keeps the energy consumption projection from the NEP.
- **APLUS Energy 2030 coal phase-out scenario.** The 2021 APLUS report includes a coal phase-out by 2030 scenario, but models the period from 2021 to 2035. This assumes that various coal incentives – including the capacity mechanism payments – are removed. Updated models extending to 2050 are being developed for commercial purposes. The main parameter of the model is an assumed carbon price.

Although the focus of this paper is on transition risks as they are highlighted in the chosen scenarios, the consequences of slower and less financially risky transitions – that is, less ambitious climate action – will likely result in very high physical risks, with all the effects on the financial sector and broader society that those entail. A rapid but orderly and just transition away from fossil fuels and towards low-carbon power generation and greater energy efficiency is overall a much cheaper and less risky proposition than a climate-changed world.

Comparing electricity projections

The following section compares projections from different models of Turkish electricity supply and demand to 2050. The authors held interviews with several Turkish experts, which bolstered the understanding and analysis of the projections. GCAM data is available for both electricity generation (supply) and consumption (demand). These figures are different because various points in the supply chain from the generator to the consumer are vulnerable to electricity losses. These are mainly categorised as transmission losses, distribution losses and others, including electricity theft. Figure 11 compares GCAM generation and consumption projections across the three scenarios.

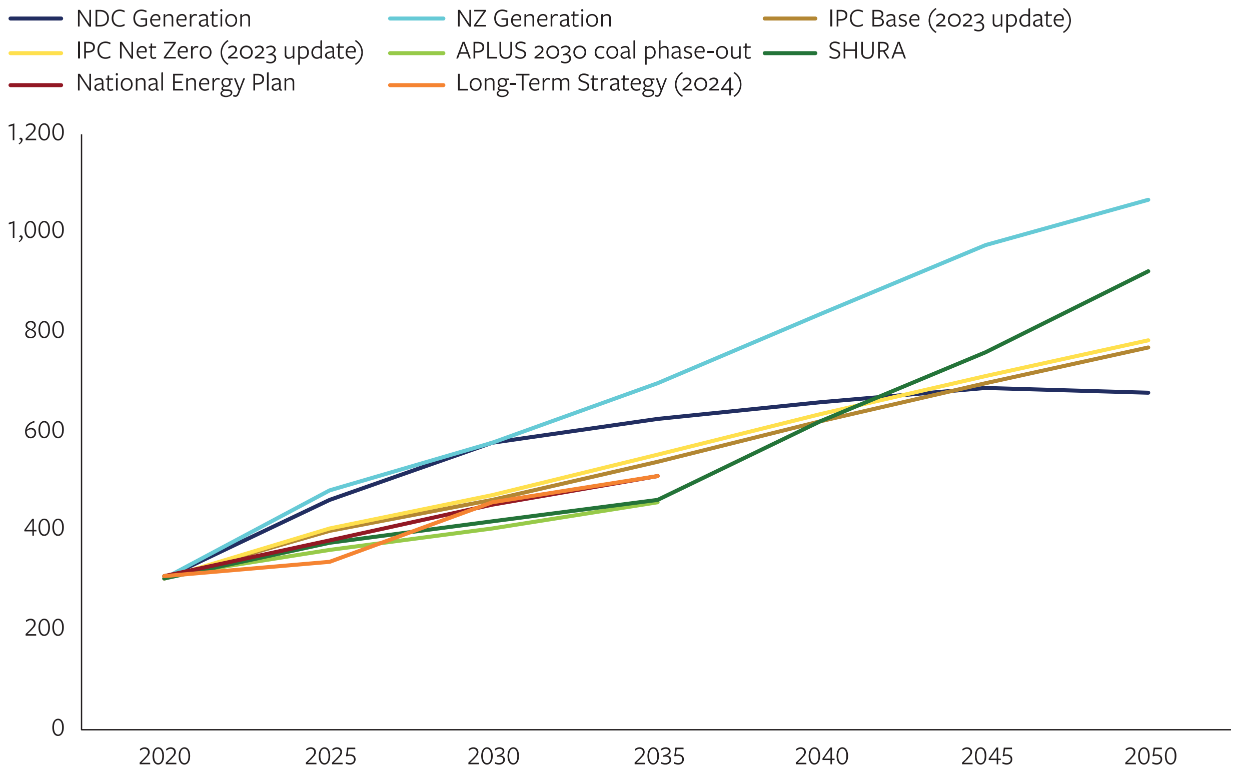
Figure 11 GCAM generation and consumption projections across scenarios to 2050 (TWh)



Source: authors' calculations based on data from NGFS

The difference between generation and consumption fluctuates considerably across this timeline – more than one would expect from average losses in the system. This may be partly explained by imprecision in the way GCAM works out its projections for Türkiye: it calculates demand and supply at a regional level first; approximates Turkish contributions based on indicators like the size, population and Türkiye's gross domestic product (GDP) relative to the region; and finetunes it based on a comparison to Turkish policies to produce 'downscaled' results. The region to which GCAM assigns Türkiye is 'non-EU'.[1] This may mean that consumption and generation are 'downscaled' separately to each other, leading to the variation in difference between the two. Comparing GCAM data to Turkish models is complicated by the fact that many of the latter take transmission data as input for both generation and consumption, making them equal because they include transmission losses but not distribution losses. Figure 12 compares some of these Turkish models to the GCAM generation data.

Figure 12 Turkish models versus GCAM generation data to 2050 (TWh)



Source: authors' calculations based on data from NGFS

Demand projections in 2050 are much higher under the GCAM NZ scenario, reflecting the electrification of transport and heating, compared to the non-GCAM models. Demand under the NDC scenario is the lowest level of all the 2050 scenarios. In comparison, the IPC Base and NZ scenarios differ little in total demand, reaching 768 and 781 TWh respectively in 2050. The SHURA projection sees demand accelerate from 2035 and then again from 2045, reaching 987 TWh in 2053 (which is equivalent to 900 TWh in 2050).

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1 GCAM 7.0's Non-EU region members are: Albania, Bosnia and Herzegovina, Croatia, Macedonia, Montenegro, Serbia, and Turkey.

The second distinction is that demand in the GCAM scenarios rises quicker than in the other models, before (in the NDC case) slowing down again to meet the acceleration of the other models. This applies to both the APLUS projections and to the government's own findings published in the 2022 National Energy Plan and the 2024 Long-Term Strategy.

While the GCAM scenarios may be overestimating demand growth, due to the imprecision of its downscaling algorithm or to a possible bias towards high demand growth based on high carbon price assumptions (Vaze and Gilmour, 2024), the Turkish models may also be underestimating electricity demand over the period. For a start, the data in the IPC model does not include distribution losses, unlike the GCAM generation data. Adding 5–10% to include these losses would start to close the gap for all the models.

In the IPC Base scenario, the growth in demand for power is calculated at 4.2% until 2030, and 2.6% from 2030–2050. This matches the accompanying assumptions about slowing GDP growth over the period. The Net Zero by 2050 scenario, with its almost identical projections for demand, seems to underestimate the additional power demand from the increasing electrification of heating, transport and industry necessary to reach net-zero emissions. One possible contributor to the underestimate is the stated coefficient of heat pumps, which is assumed to reach 4.7 in 2030 and 5.1 in 2050 (Sahin et al, 2021). Such efficient heat pumps would dramatically reduce the total energy demand of heating compared to the current gas- and coal-powered methods, meaning only a small rise in electricity demand as those methods switch to electricity. Similar assumptions about efficiency in other sectors may have nullified the expected additional demand from electrification of transport and industry. The IPC is updating its roadmap report in 2025, and many of these assumptions will be revisited. This will likely revise the generation projections higher, closer to those envisaged in the GCAM Net Zero scenario.

The SHURA Net Zero scenario is closer to GCAM's Net Zero projection in 2050, reaching roughly 920 TWh compared to GCAM's 1065 TWh. Twenty-nine (29)% of the consumption in 2053 (Türkiye's net-zero target year), in SHURA's scenario, would be used by electrolysers to produce clean fuels for seasonal flexibility and to help decarbonise hard-to-abate sectors like steel production. However, SHURA's scenario anticipates slower electricity demand growth until 2035, at which point electrolysers are brought in and demand growth accelerates. This early trajectory is slower even than the two government projections, the NEP and LTS. This is due to SHURA assumptions of a rapid shift to less energy-intensive industries and modes of transport (Güllü et al., 2023).

The government and APLUS's scenarios for Turkish electricity demand only extend to 2035 and can only be compared to GCAM projections over the short term. None of them project the acceleration of electricity demand in the short term seen under the GCAM scenarios. The APLUS 2030 model is particularly sanguine, charting a similar trajectory to the SHURA scenario before the latter accelerates in 2035. The assumptions in the APLUS model are pessimistic about various government targets – for example, the construction of nuclear power plants – and instead focus on the use of a carbon price to rapidly phase out coal generation. Meanwhile, the government models used to project the NEP and LTS match the IPC scenarios quite closely to 2035. However, although the recently published LTS includes updated targets for renewable energy capacity, no new modelling of energy demand or electrification was included (Ministry of Environment, Urbanization and Climate Change, 2024).

Despite the limitations of the GCAM model, the authors determined to use the GCAM scenarios' projections for electricity demand to 2050. This was partly because of their ease of use to third parties seeking to analyse their transition risk, and partly because the projections for the net-zero scenario are higher in the medium term and to 2050. The implication of these higher projections is that a global scenario for net zero by 2050 needs faster electrification in Türkiye, even though it does not require that Türkiye itself reach net zero by that date. The choice is justified by assumptions of the increasing electrification of heat and transport, described in Chapter 3, which suggest that the current Turkish models underestimate the demand for electricity.

Beyond electricity demand, the analysis of transition risks requires projections of the energy mix across time. Each of the scenarios described produces a different breakdown of the energy sources used to generate electricity, including the GCAM projections. However, the latter do not include figures for installed capacity of different energy generation. The authors therefore took the most recent official capacity data and projections from the LTS and combined them with the GCAM electricity demand to 2050 to create scenarios for NDC and NZ that are more tailored to the Turkish context. The methodology for doing so and the results produced are described in Chapter 3, with further detail in Appendix 1.

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