Scaling Up Demand Flexibility

From peak management to efficient system operation

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Abstract

This report has been developed as part of the International Energy Agency (IEA) Digital Demand-Driven Electricity Networks (3DEN) initiative to examine the growing importance of demand flexibility in electricity systems amid rising demand, increased renewable energy integration and the electrification of power systems. Case studies in chronological order to examine the changing role of demand flexibility over time from South Africa (2025), Thailand (2030) and Ireland (2035) demonstrate how demand flexibility improves reliability, reduces costs, supports renewables integration and manages network constraints. To realise these benefits, the report emphasises the role for smart technologies, inclusive policies, regulatory reforms and consumer engagement to scale flexibility and move away from emergency interventions, towards a more strategic and efficient system capability.

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Executive summary

Power systems are changing rapidly, increasing the value of flexibility for all types of grids

Electricity systems are undergoing rapid structural change. Demand is rising quickly – nearly twice the average pace of total energy demand growth over the past decade and around 3% in 2025 alone. Electrification of transport, heating, cooling, industry and digital infrastructure is increasing electricity demand, while low-emissions sources could provide around half of global electricity generation by 2030. As these trends accelerate, global electricity demand could double by 2035, with short-term flexibility in the Stated Energy Policies (STEPS) scenario growing between two and seven times depending on the region.

Historically, power systems have been designed around the principle that supply follows demand. However, demand itself can increasingly contribute to efficient system operation. Digitalisation, connected technologies and new market arrangements are creating opportunities for electricity demand to respond to system conditions, helping to maintain reliability, reduce costs, integrate renewable energy and defer investment in infrastructure**.**

The recent energy crisis has reinforced the importance of resilience from energy shocks. In 2026, disruption to almost 20% of global liquefied natural gas trade pushed gas prices up by around 50%, highlighting the risks of relying solely on fuel-based flexibility. Demand-side measures, including energy efficiency and demand flexibility, could increasingly contribute to energy security, affordability and resilience.

Demand flexibility is already delivering value today

This report, part of the IEA Digital Demand-Driven Electricity Networks (3DEN) initiative, examines how the role of demand flexibility could evolve through three case studies representing different stages of power system development: South Africa in 2025, Thailand in 2030 and Ireland in 2035. These case studies illustrate how electricity demand could develop over time from passive load into an active system resource.

Demand flexibility is already reducing the cost of managing peak electricity demand. In South Africa, demand flexibility measures have already avoided around 1.5 GW or 5% of annual peak demand. During periods of high demand, this has reduced peaking generation requirements by up to 20%. Although this generation contributes only around 1.4% of annual generation in South Africa, it accounts for approximately 14% of total system operating costs, illustrating how targeted reductions in peak demand can deliver important savings.

Demand flexibility also strengthens reliability during periods of system stress. In South Africa, the highest 3% of demand occurs during just 0.1% of the time. Demand flexibility programmes with large energy users have helped mitigate emergency load shedding through limited operation, supporting economic activity that would otherwise have been interrupted.

Over the coming decade, demand flexibility could become a core tool for efficient power systems

While demand flexibility is delivering value today, its most significant impact could lie ahead. With accelerating electrification, digitalisation and uptake of AI, flexibility could evolve from an infrequently used reliability tool to a routine operational capability that supports day-to-day system optimisation.

Demand flexibility could help manage electrification growth and get more out of existing infrastructure. In Thailand by 2030, mainly industrial flexibility could lower national peak demand by up to 13%. This could help manage rising demand for cooling, with every one-degree increase in temperature today adding around 1 GW to peak demand. Flexibility could play a crucial role in managing this by freeing up to 15% of transmission capacity on many network corridors, but increasing flows on some network lines underscores the need for stakeholder co-ordination of flexibility activation.

Other benefits include supporting greater uptake of renewable energy and reducing costs from fossil fuel generation. In Ireland, by 2035, the ambitious roll-out of flexibility technologies could reduce total energy system costs by up to 10%, lower fossil fuel dispatch, reduce renewable curtailment and strengthen energy security by mitigating exposure to volatile fuel prices. Demand response ready heat pumps could electrify the heating of around 170 000 additional homes without immediate transmission network reinforcement – the equivalent of nearly half of Ireland's current residential retrofit target.

The value of demand flexibility is highest when alternative sources of flexibility are limited. With Ireland in 2035 expected to have around five times more battery storage capacity relative to demand than Thailand in 2030, the marginal value of additional demand flexibility could be greater in Thailand. Determining the appropriate role of demand flexibility therefore requires quantifying the additional benefits demand flexibility can have, overall system needs, the availability and cost of alternative resources, and the factors that influence consumer participation and response.

The largest flexibility opportunities lie with specific end uses and not necessarily those with the most demand

Not all electricity demand is equally flexible. The greatest opportunities for flexibility are often found in specific end uses rather than in the largest electricity-consuming sectors. In South Africa today, most flexibility is provided by industrial users. However, IEA analysis shows that equipping hot water systems in just 10% of homes with smart controls could unlock an additional 600 MW of peak demand reduction, which is the equivalent to a large power station.

Electric vehicles (EVs) offer significant flexibility potential. In Ireland by 2035, both transport and heating sectors could provide a similar amount of flexibility, yet heating demand might be two-and-a-half times larger than transport demand. This reflects the high shiftability of EV charging compared with heating, which can be more constrained by thermal comfort. More efficient buildings could also enable an additional 15% reduction in renewable curtailment through heating flexibility, underscoring the mutually reinforcing nature of energy efficiency and flexibility.

Realising flexibility will depend on digitalisation and participation

Significant flexibility resources remain untapped in many countries. Scaling up the potential benefits would require accelerated deployment of smart technologies to monitor, communicate and control electricity demand. Smart meters, energy management systems, aggregation platforms, connected devices and AI-enabled analytics are needed for modern flexibility programmes. Increasing the scope for automated flexibility would make consumer trust and acceptance just as important as the underlying technologies themselves.

Interoperability is crucial to making the most of new and existing flexible technologies. For Ireland by 2035, the modelled flexibility would require substantial growth in enabling technologies, including an eleven-fold increase in smart EV chargers – making up around 70% of total chargers – and a four-fold increase in smart thermostats connected to flexible heat pumps. This could allow electric transport and heating technologies to provide around two-thirds of flexibility potential in Ireland by 2035.

Demand flexibility could lower operating costs, infrastructure investment, and peak demand, improving affordability for all consumers. Well-designed flexibility programmes could reduce operational costs in both Thailand and Ireland by around 10%. However, not all consumers might be able to participate equally in flexibility programmes, so careful policy design is needed to avoid penalising households less able to shift demand. If deemed a part of wider policy priorities, targeted support would be needed to more broadly share participation benefits.

Scaling up flexibility now depends on policy, planning and market design to address implementation risks

For proven digital technologies, scaling up demand flexibility will be a policy and market design challenge. Demand flexibility-ready and interconnected devices are commercially available and are increasingly deployed globally. However, planning and market processes can often exclude demand flexibility despite its potential to improve system efficiency and reduce costs.

Successfully scaling up flexibility requires addressing implementation risks like consumer uptake and cybersecurity. If more interconnected and consumer operated devices are to play a more central role in power systems, it could increase cyber-risk, but also system dependence on consumer participation. Management of these risks will influence the extent to which demand flexibility could reliably provide grid services.

Better understanding of demand flexibility potential, costs and system value can help countries determine its role in future power systems, alongside efficiency, generation, networks, and storage. This report shows how flexibility could become an increasingly important component of modern electricity systems by managing growing demand, integrating renewables and improving system efficiency. Realising this value at scale may depend on the extent to which flexibility is considered in planning, investment and policy decisions through improved valuation methodologies and enabling regulatory frameworks.

Chapter 1. The strategic role of flexibility in the Age of Electricity

Power systems around the world are undergoing a period of rapid structural change. Long-established assumptions about how electricity systems are planned, operated and financed are being challenged by rising demand, changes to generation mixes, digitalisation and renewed energy market volatility. Electricity systems are entering a new phase that can be characterised by rising demand from economic development and the electrification of end uses, as well as by growing shares of variable renewable generation and increasing exposure to disruptions.

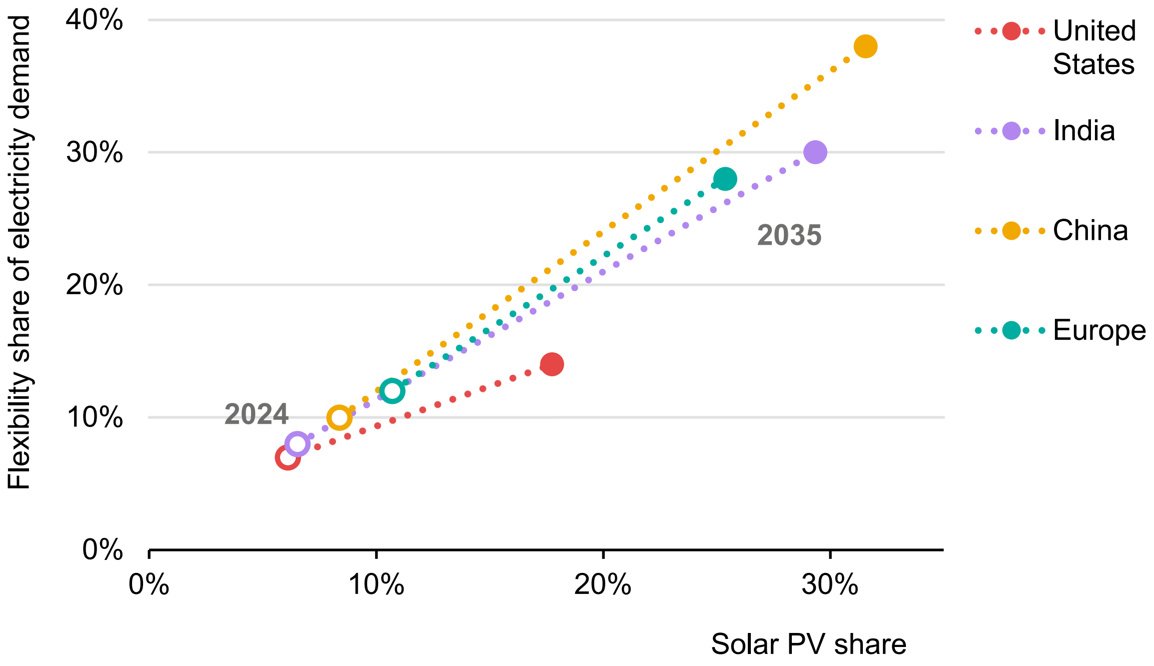
Rising demand and changing supply dynamics

Electricity grew at around 3% in 2025 – twice the rate of overall energy demand in the last decade – and it is set to increase by as much as 50% in the coming decade. The buildings sector is the single largest sector contributing to demand growth, accounting for almost 45% of the total, driven by increased uptake of air conditioners (ACs) and heat pumps, as well as the rise of data centres. Recent policies introduced across several economies in response to the ongoing global energy crisis are also accelerating electrification in buildings and transport, particularly through support for electric vehicles, heat pumps and electric cooking technologies. In 2026, it is expected that almost 30% of new cars sold worldwide will be electric. In 2025, solar photovoltaic emerged as the leading driver behind the expansion of global energy supply, contributing more than 25% to the overall increase in energy. As these trends continue, low-emissions sources are set to generate more than half of all electricity globally by as early as 2030.

The importance of flexibility to meet new grid challenges

The above trends are fundamentally changing how power systems are planned and operated. Managing *when* and *where* electricity is used is increasingly becoming as important as managing *how much* electricity is generated. At a global level by 2035, modelled demand for short-term flexibility could increase by two to seven times from today, according to the IEA Stated Policies (STEPS) scenario. The appropriate mix of flexibility resources will differ across power systems, reflecting local demand patterns, generation mixes and network constraints, and will ultimately depend on national policy and system planning decisions. Traditional supply-side responses are effective at responding to increased demand to ensure security of supply, but they can be slow to deploy, and capital-intensive. Demand flexibility, however, offers a complementary approach that could be mobilised faster and scaled more incrementally.

Modelled short-term flexibility growth for selected countries in the IEA Stated Policies (STEPS) scenario, 2024 and 2035



Notes: EVs = electric vehicles; solar PV = solar photovoltaics. Short-term flexibility is the average hourly ramp of the residual load for the top 100 hours, divided by average electricity demand. Thermal includes fossil fuels, nuclear, bioenergy, hydrogen and ammonia. Curtailment refers to the curtailment of wind and solar PV generation.
Source: IEA (2025), World Energy Outlook.

Understanding the different sources of value from demand flexibility

Demand flexibility creates value through various mechanisms, which affect different aspects of the electricity system. Similarly to the benefits of energy efficiency, many sources of value can arise through improved utilisation of existing infrastructure and avoiding additional system costs, but flexibility is concerned more with shifting the timing of demand rather than the amount of it.

In the short term, demand flexibility can reduce operating costs by lowering the use of high-cost generation during periods of system stress. Avoiding or reducing the operation of peaking plants can lower fuel consumption and reduce wholesale electricity expenditures during high price periods. These benefits are often realised immediately and are most visible in systems facing tight supply margins or high fuel prices.

In the medium to long term, the largest economic value of demand flexibility often comes from reducing or delaying the need for additional infrastructure. Digital technologies could defer an estimated USD 1.8 trillion of grid investment through to 2050. By lowering peak demand, relieving local network constraints and enhancing the use of existing assets, flexibility can optimise investment in generation capacity, electricity networks and storage.

Demand flexibility can also create value through improved utilisation of low-cost electricity generation, building on the above benefits for efficiency. Shifting demand to periods of high renewable output can reduce renewable curtailment, lower fossil fuel consumption, relieve network congestion and improve the efficiency of the system. In systems with growing shares of variable renewable generation, these benefits can become increasingly important over time.

The distribution of these benefits varies across stakeholders. Through improved reliability, lower operational costs, reduced investment requirements and lower emissions, overall costs can be reduced for system and network operators. This should translate into consumer cost savings depending on cost recovery mechanisms, meaning not all consumers need to participate directly in flexibility programmes to benefit from them. The greatest cost savings would however accrue for participating households or businesses, which could raise issues of fairness.

Realising these benefits is however not without cost. The extent of these benefits will depend on comparison with cost of enablers and how they compare with alternative investments in generation, networks, and storage. The value of demand flexibility ultimately depends on whether the system benefits exceed the costs of enabling, operating and maintaining flexibility resources, and what role policy makers decide it should play in future power systems.

The value of flexibility is elevated by affordability and energy security concerns

Affordability considerations are taking centre stage. Electricity prices in many regions have remained elevated in recent years compared with long-term historic price trends. In countries with liberalised electricity markets, where a marginal, or “pay-as-clear”, pricing system exists, the highest-cost generator needed to meet demand sets the market price for all electricity dispatched during a set period.

Following the Russian Federation's full-scale invasion of Ukraine in 2022, gas prices reached unprecedented levels, driving up electricity prices in markets where gas frequently sets the market price. Although prices later declined, they nevertheless remained around double the pre-crisis levels.

The recent conflict in the Middle East has led to renewed volatility in fuel markets. Oil prices recorded their largest ever monthly increase in March 2026. The loss of almost 20% of global liquefied natural gas supply following the effective closure of the Strait of Hormuz distorted short-term gas markets and has driven prices in Asia and Europe to their highest levels since the 2022-2023 energy crisis.

The oil crises of the 1970s also triggered price spikes, but this resulted in major advances in energy efficiency, strategic fuel diversification and the creation of new institutions, including the IEA, to shore up energy security. The recent conflict in the Middle East, which created a situation more serious than the energy crises of 1973, 1979 and 2022, underlines the untapped value of demand-side measures such as energy efficiency and demand flexibility to insulate against supply shocks.

Accelerated electrification as a crisis response tool

Government actions recorded in the IEA 2026 Energy Crisis Policy Response Tracker indicate that electrification is increasingly being considered as a near-term energy security and affordability measure. In response to the energy crisis resulting from the recent war in the Middle East, several countries introduced measures to accelerate the electrification of transport, heating and other end uses to help reduce exposure to volatile fossil fuel markets.

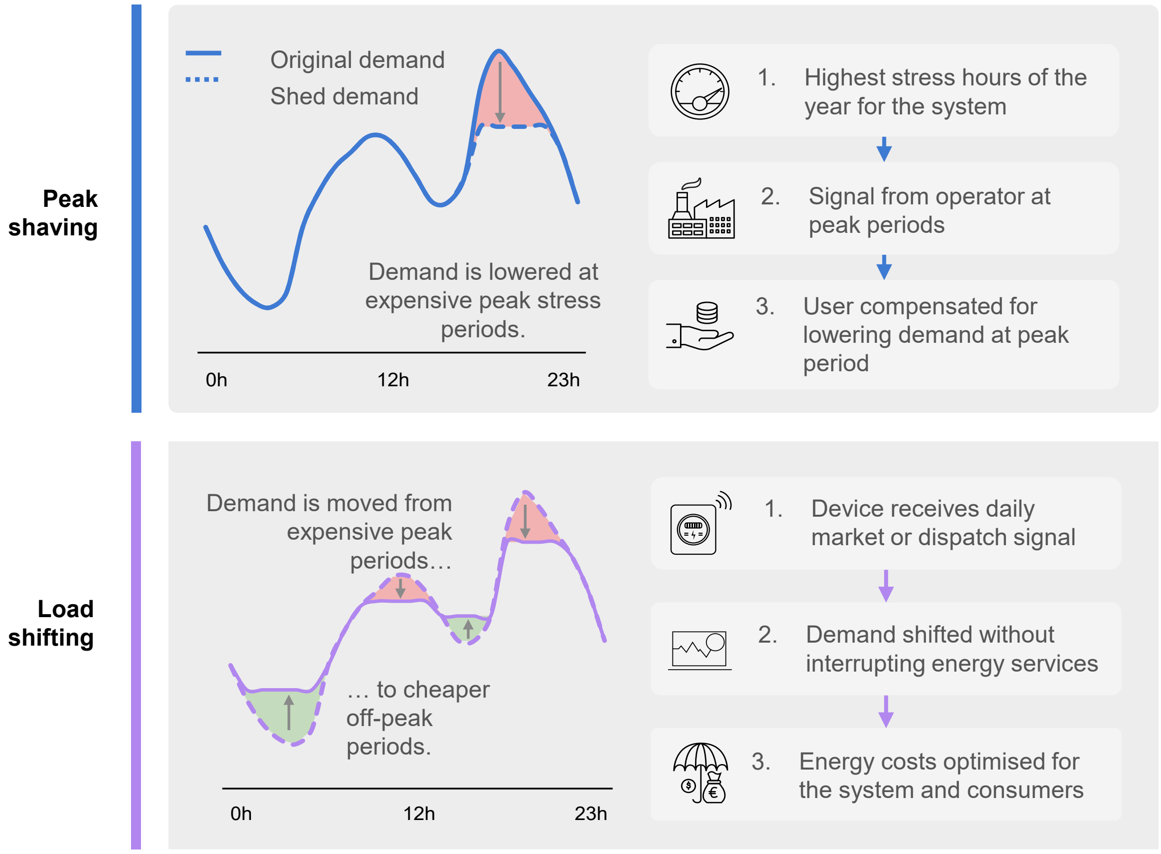
Governments have continued to adapt their policy responses to dynamic circumstances. France has expanded its national electrification plan, with support for electric vehicles and a target of one million annual heat pumps installations by 2030. The United Kingdom increased grants to electrify residential heating, as well as taking measures to improve the economics of electrification by lowering the electricity-to-gas price ratio. Emerging markets and developing economies (EMDE) are also acting. Cambodia reduced import duties on electric vehicles, chargers, electric motors and electric cooking appliances, while Viet Nam extended tax reductions through to 2030 and registration fee exemptions for EVs through to 2027.

While electrification and the integration of low-cost clean energy can contribute to affordability and energy security, it could also increase peak electricity demand. This growth will accentuate the need for demand-side flexibility to manage growing loads while at the same time maintaining reliable and affordable power systems.

Key types and enablers of demand flexibility

Demand flexibility can be divided into two main mechanisms: peak shaving, which is more widely used today, and load shifting, which is increasingly the focus of pilot projects around the world. Understanding these components is essential in assessing where flexibility could be realised in practice. Demand flexibility can be either implicit, through indirect consumer responses to price signals (e.g. time-of-use [ToU] tariffs), or explicit through agreed and verified dispatch signals.

How peak shaving and demand shifting work in response to activation signals



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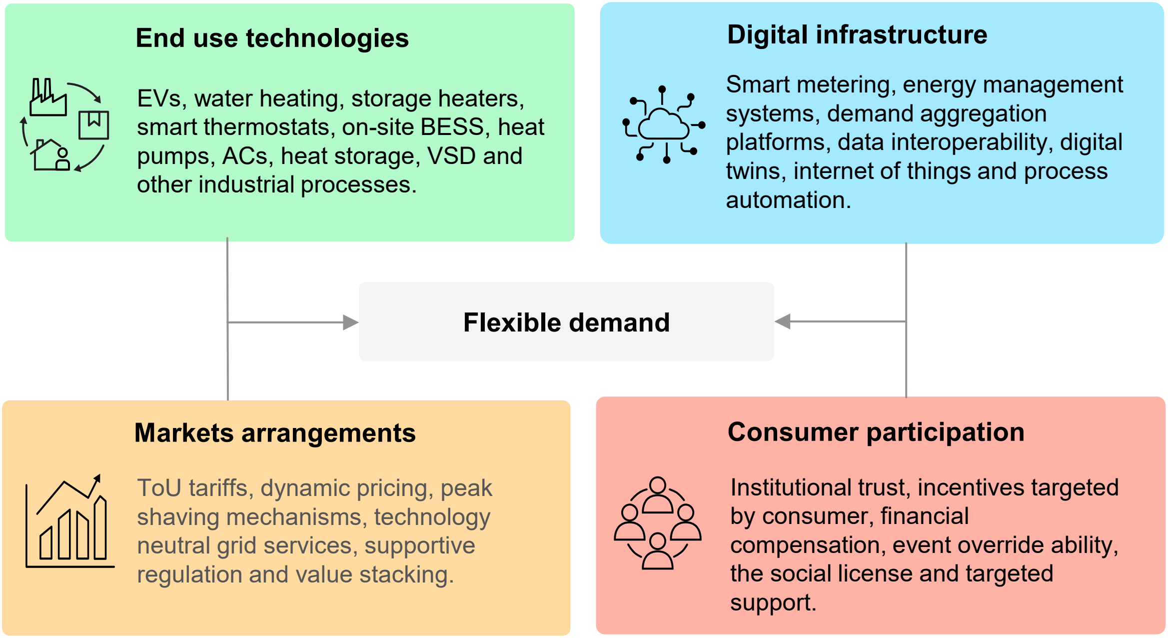
The potential for electricity demand to become flexible and available to the grid will depend on interactions between end-use technologies, digital infrastructure, consumer participation and market arrangements.

- **Shiftability of end-use technologies**: the ability of loads to be flexible depends on the end use and technology, which is generally higher where operation can be shifted without affecting service quality. Water heaters and air conditioners (ACs) have long been used in peak shaving programmes, while newer technologies like EVs are providing more diverse options. The amount and timing of this shiftability can vary with the type of technology, thermal inertia, storage capacity and operational constraints.

- **Controllability by means of digital infrastructure**: the share of load that is connected to communicable equipment, including the hardware needed to record data, seamlessly transfer data between stakeholders, and control end uses. Technologies are increasingly being designed as demand response ready, with flexibility capabilities built in. Increasingly sophisticated control algorithms and AI-enabled optimisation could improve the device responsiveness while maintaining consumer comfort and service quality.
- **Consumer participation and acceptability**: the willingness of end users to own connected appliances, and participate to programmes shift demand, whether manually or without overriding automatic activation. The ability of households and businesses to shift demand varies on demographic factors, consumer trust in institutions, the ability to override device functions and the timing of requests. For commercial and industrial users, this ability to shift demand will depend on personnel capacity, organisational aspects and other industry-specific constraints. The distinction between shedding and shifting can also vary by end user.
- **Market arrangements**: how flexibility is included, regulated and renumerated in electricity markets. Simplest of these are ToU tariffs to deliver limited implicit flexibility, but other mechanisms are needed to go further. Compensation for participation in peak shaving or demand shifting can be supported by including flexibility in the real-time grid services, particularly with stacking of revenue from different programmes. A competitive market for demand aggregation can ensure that the revenue that arises from supporting the grid can filter through to consumers.

Key enablers of flexible demand



End use technologies

EVs, water heating, storage heaters, smart thermostats, on-site BESS, heat pumps, ACs, heat storage, VSD and other industrial processes.

Digital infrastructure

Smart metering, energy management systems, demand aggregation platforms, data interoperability, digital twins, internet of things and process automation.

Flexible demand

Markets arrangements

ToU tariffs, dynamic pricing, peak shaving mechanisms, technology neutral grid services, supportive regulation and value stacking.

Consumer participation

Institutional trust, incentives targeted by consumer, financial compensation, event override ability, the social license and targeted support.

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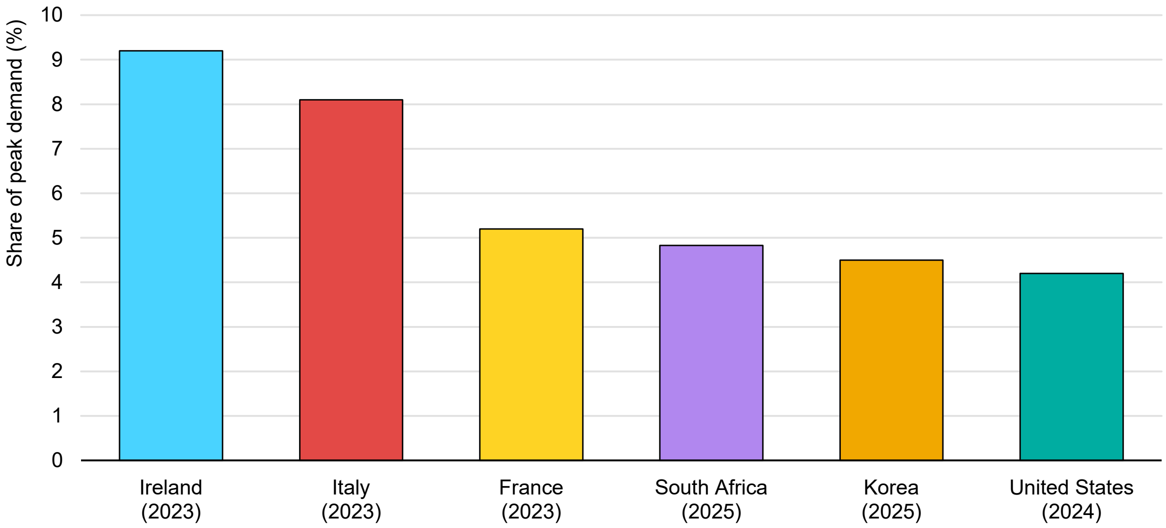
Note: AC = air conditioning; BESS = battery energy storage systems; EVs = electric vehicles; ToU = time-of-use (tariffs); VSD = variable speed drive.

Moving from emergency demand response to strategic system capability

Historically, demand flexibility has been mainly used as an emergency resource, activated during periods of system stress or supply shocks, with many demand response programmes originating from the energy crises of the 1970s. More recently, up to 9% of peak demand in major economies has been managed by peak shaving programmes. The ongoing energy crisis has again prompted countries to take peak demand measures. Korea, for example, has issued guidance to reduce peak electricity demand through flexibility and is encouraging citizens to charge electric vehicles and other devices during the day or late at night, rather than during evening peak hours.

Explicit demand response capacity as a percentage of the peak load for selected electricity systems, 2023-2025



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Note: Values represent explicit demand response capacity (contracted or technically available) as a share of each system's peak load.

Sources: IEA analysis based on data from EirGrid (2024), Terna (2024), KPX (2025), RTE (2024), EIA (2025) and Eskom (2025).

Alongside these more traditional peak reduction measures, governments are shaping how electrified demand is deployed to support future system flexibility. The 2026 energy crisis has seen Australia announce new funding for an EV charging infrastructure and the electrification of postal delivery fleets, while the Lao People's Democratic Republic has prioritised charging and battery-swap infrastructure for electric freight transport. Such measures have implications beyond fuel switching given that digitally connected end uses such as electric vehicles, heat pumps and battery systems could increasingly provide controllable and shiftable demand resources for the power system.

As systems become more electrified and decentralised, demand flexibility could evolve into a structural capability to support improved day-to-day system efficiency, resilience and investment optimisation as opposed to acting as a last-ditch effort to manage grids. Realising this transition would require increasingly sophisticated forecasting, optimisation and control capabilities capable of co-ordinating large numbers of distributed energy resources in real time. This could have a wide range of system benefits as detailed in the recent IEA publication The Value of Demand Flexibility.

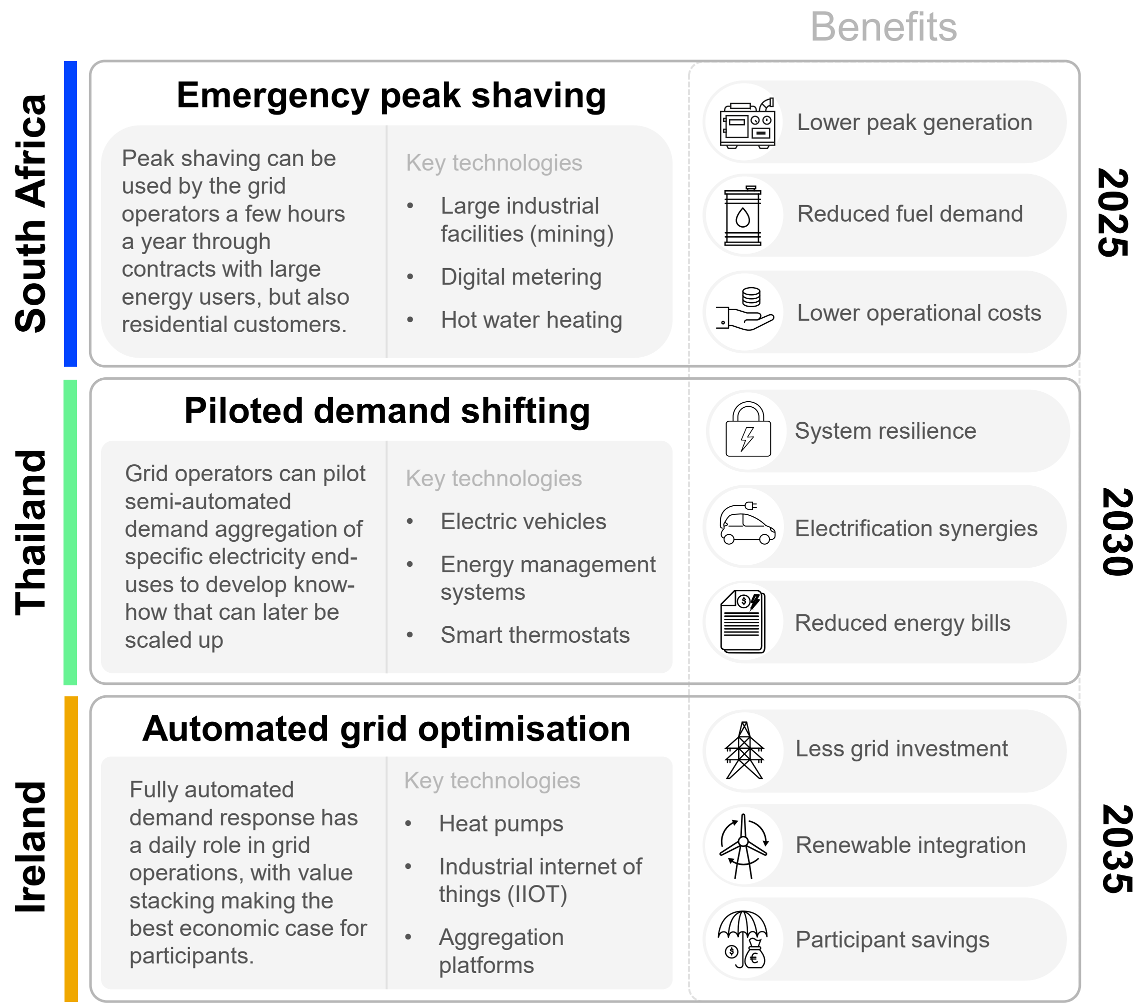
Yet despite growing recognition of its potential, deployment of demand flexibility remains irregular. In many countries, regulatory frameworks, digital infrastructure, market arrangements and institutional capabilities have not evolved at the pace required to scale up flexibility at scale.

Governments and system operators will ultimately determine the future role of demand flexibility in power systems. For wider deployment, better evidence on the resource, costs, risks and system value would support decision making. Assessments based on demand data and forward-looking scenarios can help quantify opportunities, inform planning processes and enable flexibility to be considered alongside supply-side options. Such assessments can also help identify where demand flexibility offers the greatest value and where alternative resources may provide a more cost-effective solution. Consideration of factors such as consumer participation, delivery risks and cyber security may also help policy makers assess the circumstances under which demand flexibility can provide value relative to alternative resources.

Chapter 2. Case studies representing different stages of flexibility development

To better understand and quantify the value of demand flexibility, this report presents three case studies anchored in **specific countries and time frames**. Each case study describes different system configurations, illustrating how demand flexibility is currently used, its evolution in the near term and what it could deliver if scaled up over the next decade.

Illustration of three country case studies and time frames in this report, 2025-2035



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Note: The benefits and end uses are not exclusive to each country case study.

The three case studies selected for this analysis illustrate how the role of demand flexibility may evolve as power systems change. In the case of South Africa, flexibility is primarily used to manage reliability risks and reduce peak demand during periods of system stress. The case of Thailand illustrates a transition towards broader market-based flexibility alongside ongoing electrification and demand growth accelerate. Ireland represents a stage where flexibility becomes increasingly integrated into the routine operation of a highly digitalised and electrified power system.

- **South Africa in 2025** represents the most established approach to demand flexibility. Programmes focus on emergency peak shaving, where peak demand is reduced for a few hours of the year through contracts with large energy users, and increasingly with other sectors. Although the duration is short, they target periods of extreme system stress and high marginal costs, where even modest reductions in demand have had large impacts on system reliability, energy security and costs.
- **Thailand in 2030** reflects approaches that are emerging today. As electricity demand grows and new end uses are electrified, digitalisation enables more frequent and structured interaction between grid signals and demand. Pilot projects play a key role in building experience, particularly in aggregating specific end uses to participate in load flexibility programmes. Such examples highlight how countries might move beyond one-off interventions towards the more routine, cost-effective use of demand flexibility.
- **Ireland in 2035** represents longer term ambitions. As the power system integrates higher levels of renewables, the need for affordable flexibility increases significantly. At the same time, the more widespread deployment of connected devices will enable demand-side resources to participate across multiple grid services. Combining and “stacking” revenue from these services will allow participants to capture greater value, helping to drive higher uptake and ultimately making demand flexibility into a core component of system operation rather than a marginal tool.

These case studies combine IEA modelling and in-country data, integrating system modelling with observed operational experience and policy analysis. The focus is on quantifying the value that demand flexibility could provide to power systems and what policy supports may be required. Case studies draw on national datasets, stakeholder inputs and detailed sectoral assumptions to reflect local system characteristics, while applying consistent analytical approaches to enable comparison across contexts. They do not assess the full costs of deploying flexibility measures, which can vary significantly across technologies, end uses and jurisdictions, but it would be necessary to perform a full assessment of the cost-effective demand flexibility resources available to a country.

Chapter 3. Demand flexibility today: The case of South Africa, 2025

Why flexibility matters

Today, the primary value of flexibility lies in its ability to address immediate system stress. Electricity demand growth, and delays in delivering new generation and network infrastructure, are increasing pressure on power systems. These pressures increase the value of demand flexibility in avoiding service interruptions, managing peak demand and containing operational costs, which is not limited to systems with high shares of renewables or widespread electrification.

Globally, the main driver for demand flexibility today is system security

In advanced economies, many thermal generation fleets are ageing, with declining availability and rising maintenance costs. Alongside growing electricity demand and plant retirements, this has increased the likelihood of unplanned outages and reduced operational margins as highlighted by reviews in France and Australia. Peak demand periods, though infrequent, place disproportionate stress on power systems and determine the scale of required capacity. Peaking plants, which operate for brief periods over the year, can carry high operating costs, amplified by fuel price volatility, raising system operating costs at periods of greatest stress.

In many systems, historic underinvestment energy infrastructure, combined with long lead times for new assets, has strained the ability of supply-side solutions to respond quickly to emerging reliability risks. New generation and network investments are capital intensive and typically require many years to plan, permit and build. Wait times for new gas turbines are now up to five years in some Asian economies and a minimum of six years in the United States. Utility-scale batteries are, however, rapidly emerging as a cheaper alternative of daily flexibility that could be deployed in a matter of months.

Today, demand flexibility remains limited in scale and participation at the global level

Power system flexibility is currently dominated by supply-side resources. Historically, thermal generation and hydropower have provided the bulk of short-term balancing, ramping and reserve services that have kept electricity systems stable. However, the role of battery storage has grown in recent years, now accounting for around 10% by energy of short-term flexibility.

Demand flexibility is currently constrained in scope. It functions mainly as a reliability and cost-containment tool, deployed at expensive peak demand periods. Delivery mechanisms are often manual or analogue, relying on direct instructions and simple control technologies, with participation concentrated among large industrial and commercial users. Implicit and more broadly distributed flexibility through time-of-use (ToU) tariffs for smaller users has also contributed but has not reached its full potential. Wider participation has been constrained by limited digital infrastructure, automation, prohibitive regulation and market access.

Despite only being a small share of annual electricity demand, the 4-9% of peak shaving deployed in major economies is comparable to that of peaking generation. Large electricity users can reduce or shift peak consumption, helping to avoid more costly disruptions like emergency load shedding or blackouts, which cost the global economy an estimated USD 100 billion a year or around 0.1% of global gross domestic product (GDP). While this contribution is already notable for avoiding outages and reducing reliance on high-cost peaking generation, it can be fragmented and only partially reflected in planning and policy frameworks.

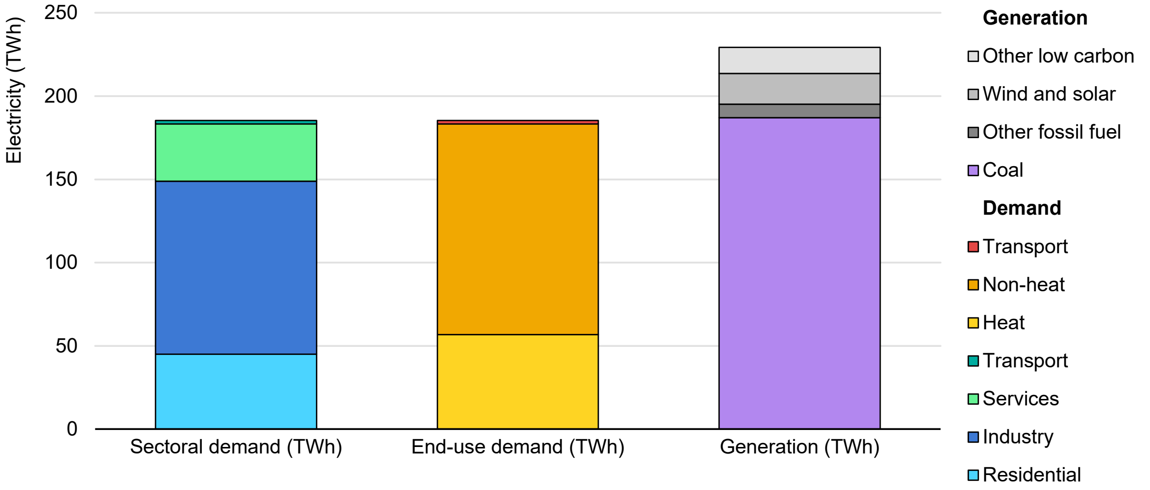
South Africa's power system and demand flexibility resources

In South Africa, demand flexibility has increasingly complemented supply-side measures. Coal provides around 80% of electricity, but it's declining availability in recent years has lowered the system's margins and increased sensitivity to periods of high demand. Despite only providing 1.4% of generation for limited high-stress hours in 2024, peaking generation accounted for around 14% of total operating costs, highlighting the potential for reducing or shifting peak demand.

At peak demand periods, the system has relied on peaking generation to maintain stability, with the use of open-cycle gas turbines (OCGT) up by nearly half from 2025 from 2021 levels, but down 40% from a high in 2024. This response to short-duration stress carries high operating costs and exposure to volatile gas prices, so reduced usage led to expenditure on OCGT generation falling by USD 1 billion in 2025 compared with 2024 - around 10% of energy costs.

The unavailability of generation has historically disrupted electricity supply, resulting in emergency load shedding that is estimated to have reduced GDP growth in South Africa by around 1.5% in 2023. This economic fallout emphasises the role of both demand- and supply-side solutions in managing short-term imbalances and limit disruption while longer term investments were implemented in all sectors. In 2025, Eskom reported an annual reduction of 97% in load shedding, due largely to improvements in generation availability, but also contracted peak shaving.

Annual electricity demand, end-use demand and generation output for South Africa, 2025



IEA. CC BY 4.0.

Notes: The difference in sectoral and end-use demand as opposed to supply denotes network losses. Heat demand refers to space heating and industrial processes. Other low carbon includes nuclear, hydro, concentrating solar power, landfill gas, and biomass.

Sources: IEA (2025), World Energy Balances; Hughes and Larmour (2020), Residential Electricity Consumption in South Africa.

Industry accounts for nearly 60% of annual electricity demand – more than double that of the residential sector. Mining is among the largest sub-sectors, but a single aluminium smelter also accounts for around 5% of Eskom's electricity sales. Around 80% of industrial energy users have used ToU tariffs since the 1990s. This considerable demand, and generally greater sensitivity to prices than other consumer types, means industry has a large role in South Africa's power sector.

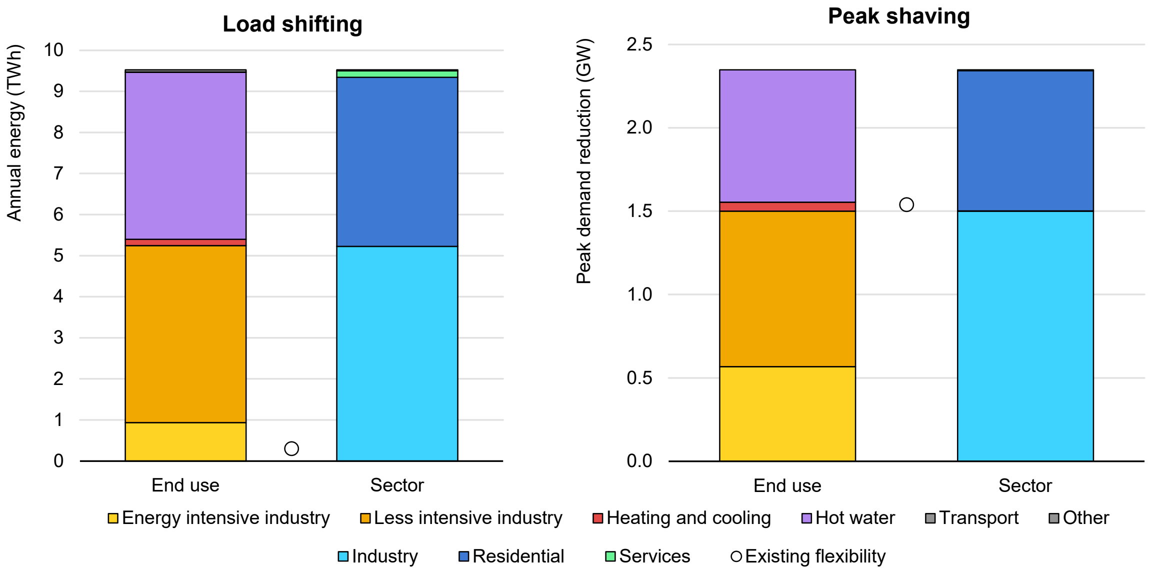
South Africa's flexibility resource is largely industrial, with growing potential for aggregated hot water heating

South Africa already has one of the most comprehensive demand response programmes in an emerging market. Programmes in residential and commercial sectors reduce peak demand by up to 2%, with its Demand Management Programme illustrating how contracted supply interruptions can be valued using estimates of the economic cost of outages. The programme has delivered up to

1.5 GW of peak shaving[1], mainly from large industrial consumers, with a smaller but significant amount from residential water heaters and pool pumps.

In the near-term, tripling the historic rollout of a hot water heating controls with more advanced control technologies to 1.2 million, or 10%, of households in South Africa could unlock 600 MW of additional peak shaving capacity. This resource would need to be activated only infrequently to minimise disruption to energy services and avoid the risk of flexibility fatigue for participating consumers. Wider realisation of flexibility potential across both residential and industrial sectors would require appropriate control and metering technologies alongside broader market reform. In industry, demand flexibility is relatively mature, particularly in the mining sector, but participation could be improved through stronger incentives.

Technical potential of demand flexibility in South Africa by sector and by end use for load shifting (left) and peak shaving (right), 2025



Notes: Other end uses include residential and commercial cooking, lighting, refrigeration, brown appliances; desalination; and data centres, which are currently less suitable for flexibility measures. The current load shifting potential assumes that industrial time-of-use tariffs reduce peak demand by 250 MW.
Sources: IEA analysis based on data from Eskom (2025) and IEA (2025), World Energy Outlook.

Industry has the greatest shifting potential at around 1 TWh annually, reflecting both current demand levels and greater technical maturity. South Africa's smart meter programme, which aims to install 6.2 million meters by 2029, could enable greater implicit flexibility in the residential and commercial sectors. Advanced water heating controls offer further shifting potential in the residential sector, where the thermal inertia of water tanks makes them well suited to this role.

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[1] IEA analysis based on data from Eskom (2025).

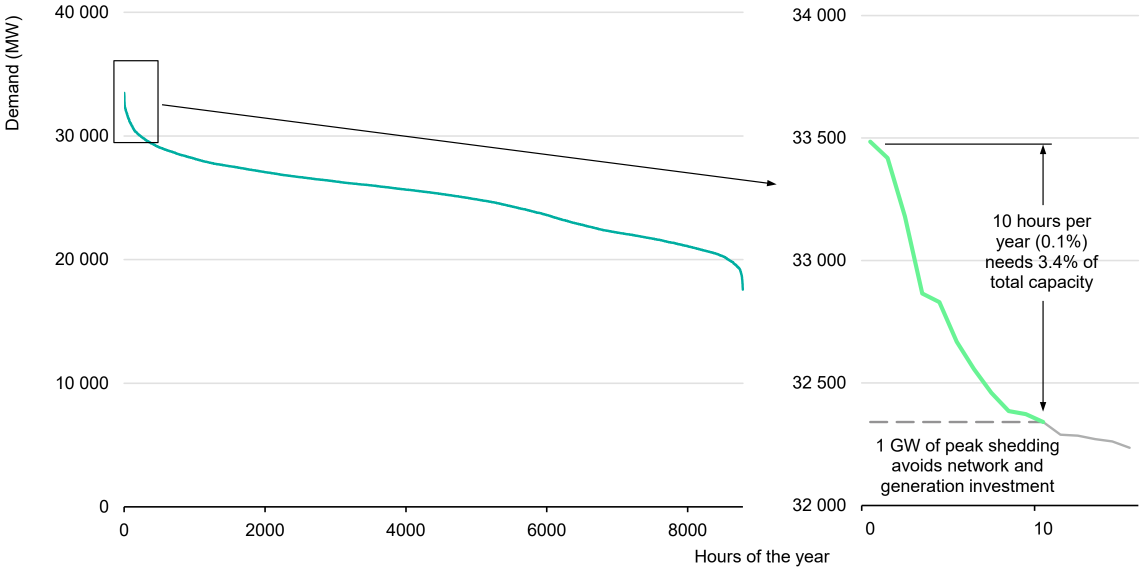
The value of demand flexibility in South Africa

In South Africa today, demand flexibility has contributed to system reliability and has lowered costs. It has reduced service interruptions during periods of system stress and displaced the use of high-cost peaking generation by lowering peak demand. Analysis of these factors shows how valuable existing flexibility has been to the system, but also its potential in the short-term.

Flexibility can address short-duration system stress

A small number of peak hours drive a disproportionate share of system capacity requirements in South Africa, like many countries. The top 0.1% of demand hours accounted for 3.4% of peak demand in 2024, meaning that investment in generation and network infrastructure is sized for conditions that occur just a few hours of the year. Demand flexibility can give system operators a tool to manage short-duration stress without additional supply capacity. Since 2004, Eskom's energy efficiency and demand-side management programmes are estimated to have reduced peak demand by around 4.5 GW, helping to alleviate pressure on the power system during periods of generation shortfall and reducing the need for more severe load shedding. Flexibility does not substitute for longer term supply investment, but it buffers the system against shocks and reduces the likelihood that stress escalates into widespread disruption.

Load duration curve for South Africa showing the share represented by periods of peak demand, 2024



Source: IEA analysis based on data from Eskom (2025).

IEA analysis of peak-shaving potential of electric water heating shows that an additional 0.6 GW of peak shaving could be achieved in South Africa on top of the existing 1.5 GW in use today by covering 10% of residential properties. Avoiding this top 2 GW of peak demand would have needed activation for just 56 hours over 2024[2], but these would be concentrated in higher demand winter months. For maximum impact, activation of these resources would be limited to times when it is most needed, maintaining utilisation within the limits defined by contracts with customers and preventing participation fatigue.

Non-firm grid connection agreements as a bridge to network expansion

To manage network constraints, some grid operators are introducing firm and non-firm connection agreements. Firm connections guarantee electricity supply year round, while non-firm arrangements allow part of a consumer's demand to be reduced or shifted during limited periods of network stress. This solution can allow businesses to connect to the grid earlier, alongside network reinforcement. Flexible connection agreements could therefore help bridge the "time-to-power" gap between rising electricity demand and the slower pace of grid expansion.

Limited flexibility could unlock significant capacity and faster connection

The potential system value is significant. The IEA estimates that non-firm connections could unlock 750-900 GW of projects currently in capacity queues. Analysis of a flexibly connected 500 MW data shows it could begin operation three to five years faster than traditional connection processes. For these constrained sites, grid power would be available for more than 99% of the time, while on-site flexibility resources would be needed for only 40-70 hours per year.

Large electricity users can be flexible in operations, but it can be complex

Large electricity users, such as data centres, are increasingly viewed as potential providers of operational flexibility, although this potential can be constrained. In March 2026, Google reported contracting 1 GW of demand response capability with utility partners in the United States. This capability included shifting or reducing portions of electricity demand during periods of system stress. Some computing workloads could also be scheduled for periods when network conditions are less constrained.

Such connections nevertheless require new grid users to assess the trade-offs between faster connections and lower grid fees, with revenue reductions when curtailed. It also requires careful management of issues relating to grid utilisation, curtailment uncertainty, cost allocation between grid users and the avoidance of discriminatory practices.

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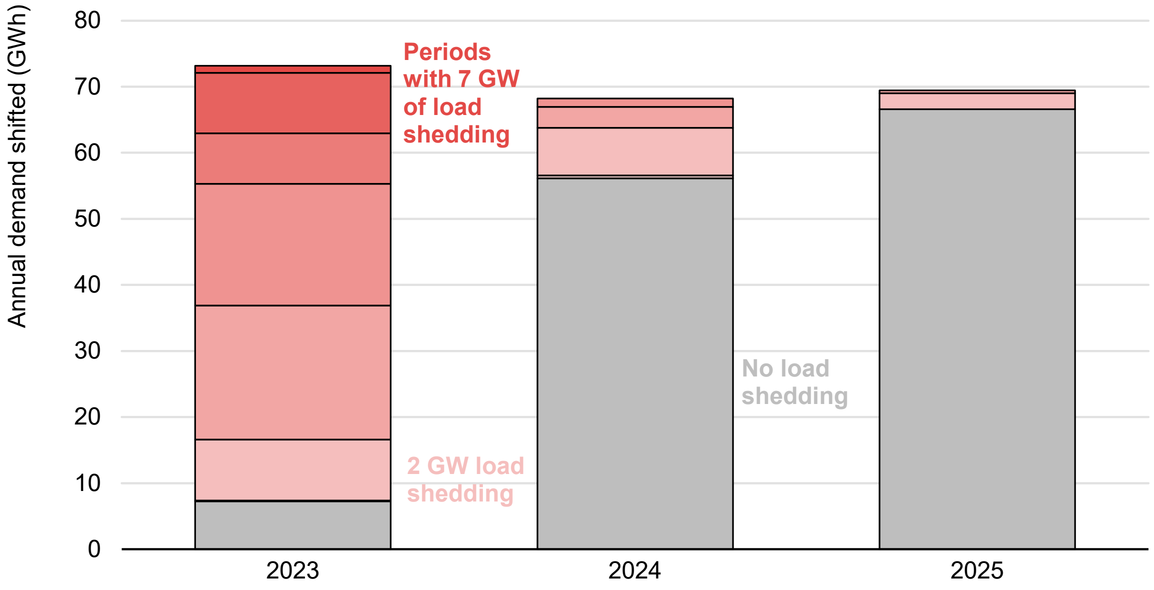
[2] IEA analysis based on data from Eskom (2025).

Peak shaving has provided value outside of crisis conditions

In 2023, reducing demand by large energy users at peak periods helped to mitigate the severity of emergency load shedding, enabling power to remain available to a higher number of consumers that would have otherwise temporarily lost access during supply-side capacity shortfalls. Since 2024, with improvements to generation availability, South Africa has continued to operate peak shaving programmes more regularly, with more than 95% of peak shaving being offered outside of load shedding conditions in 2025. While the peak shaving programme was introduced as an emergency measure, it has proven to provide value during daily peaks outside of the highest demand periods across the entire year.

Contracted peak shaving operations compared with periods of normal operation (no load shedding) and emergency load shedding in South Africa, 2023-2025



IEA. CC BY 4.0.

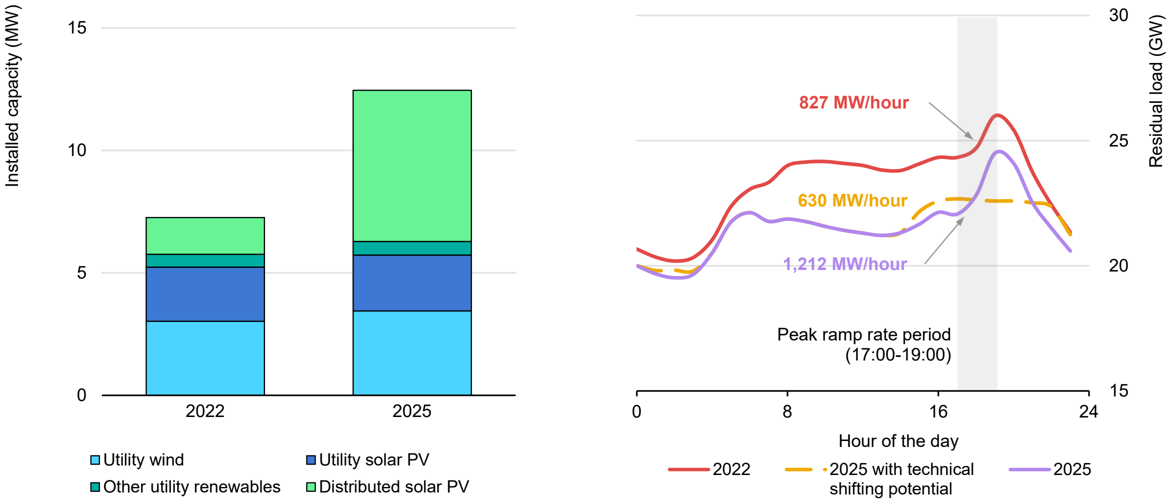
Notes: The GW of load shedding can also be referred to as a stage – e.g. stage 1 load shedding for 1 GW, stage 2 for 2 GW.
Source: IEA analysis based on data from Eskom (2025).

The total peak shaving demand contracted in South Africa has remained constant over the last three years, but its impact has evolved in the context of the power system, keeping costs down during day-to-day operation. System operators have passed on this value to participating consumers, with improved reliability for all customers. As the power system evolves, so too does the role that flexibility is asked to play.

Demand flexibility helps manage growth in solar PV generation, reducing ramping requirements

Recent growth of solar PV is reshaping the demand for system flexibility in South Africa. Distributed solar PV capacity has more than quadrupled since 2022, with around three-quarters of additions in the industrial and commercial sectors, increasing the peak net load ramp rate by nearly 50%. Pumped hydro currently provides much of the system's ramping capability, but its capacity is finite and already heavily utilised. Flexible demand could help fill this gap, complementing existing supply-side resources by reducing net load during critical ramping periods. South Africa is therefore firmly placed in the second phase of the IEA Variable Renewables Integration framework, where growth is already having a moderate impact on the system.

Utility and distributed scale renewable generation (left) and net load, with and without demand shifting potential (right) in South Africa, January 2022 and 2025



IEA. CC BY 4.0.

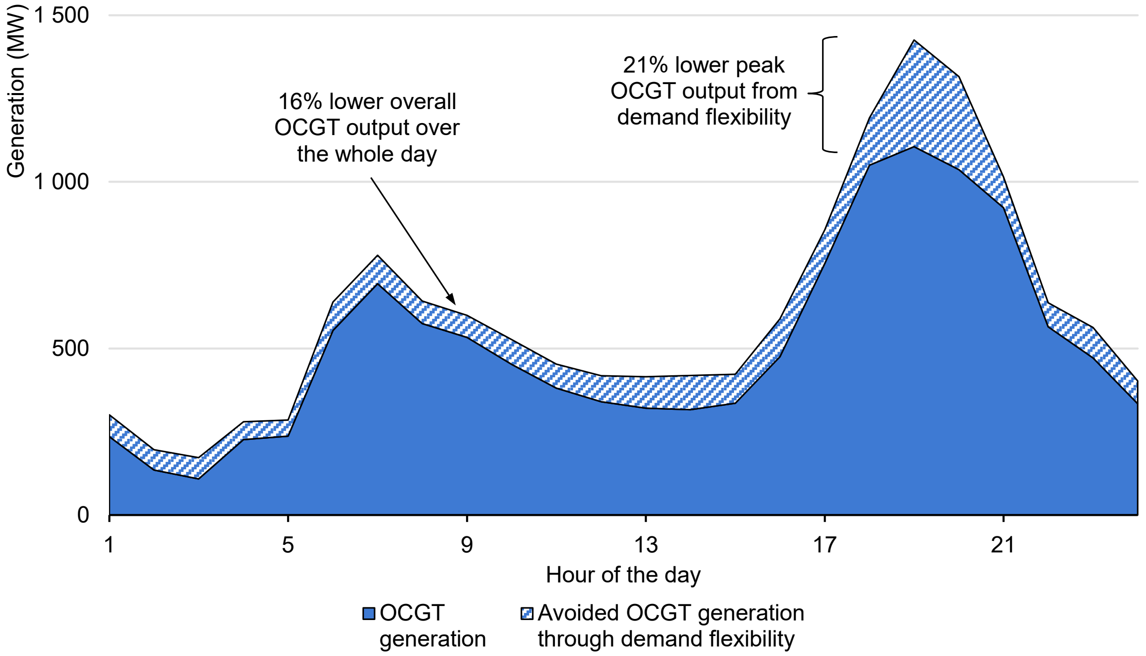
Notes: Solar PV = solar photovoltaics. "Other utility renewables" include concentrated solar power, small hydro, landfill gas and biomass. The drop in net load overnight is due to average electricity demand in South Africa falling from 2022 to 2025, not change in renewable output.
Sources: IEA analysis based on data from Eskom (2025) and Eskom (2025), Eskom weekly reports.

Utilising the current shifting potential in South Africa could help halve the 2025 peak ramp rate, freeing up pumped hydro generation for use during other periods of the day. South Africa aims to add 20 GW of new renewable capacity by 2030, and on shorter timescales than larger generation infrastructure can be developed. Demand flexibility could therefore help to manage this integration. Growth in renewables increases the value of system flexibility even at the early stages of deployment of variable renewable energy, since increased variability in net demand places new requirements on system operation. Net load ramping is needed as renewable output changes over the course of the day, increasing the burden on dispatchable generation and other balancing resources. Demand flexibility could help smooth these transitions by shifting consumption towards periods of higher renewable output or away from steep ramping intervals, avoiding a decline in overall system efficiency.

Contracted peak shaving lowers gas-powered generation during peak load

Small amounts of flexibility can deliver significant cost savings, particularly in systems exposed to fuel prices that are particularly volatile for peaking generation. In 2024, these peaking resources accounted for around 14% of operating costs for the main South African utility, despite generating only 1.4% of the energy. Demand flexibility reduces reliance on these marginal units by lowering peak demand or shifting consumption to periods when lower cost generation is available.

Avoided peaking open-cycle gas turbine generation through peak shaving for an average day during periods of contracted peak shaving in South Africa, 2022-2025



IEA. CC BY 4.0.

Notes: OCGT = open-cycle gas turbine. The analysis assumes that when contracted peak shaving was available, but emergency non-contracted load shedding was not occurring, without contracted peak shaving, the equivalent demand would be met by peaking OCGT generation from both Esko to avoid load shedding.

Source: IEA analysis based on data from Eskom (2025).

Demand flexibility has helped contain short-term operating costs by displacing more expensive peaking generation during high-stress hours. Since 2022, on days where flexible demand was contracted, it has helped South Africa to reduce peaking plant generation by around 16% on average over the course of the day, and by up to 20% at peak demand periods. With an additional 600 MW peak demand potential, through wider deployment of hot water controls, this effect and the cost savings could be even greater. Eskom has made a stated aim of reducing the share of OCGT operation in its primary energy costs of USD 10 billion in 2024.

Non-wire alternatives like flexibility and efficiency could reduce the scale and cost of grid expansion

Demand flexibility and energy efficiency can reduce both the scale and cost of grid investment. South Africa anticipates expanding its transmission network and adding up to 100 GW of generation by 2039, and while flexibility cannot displace this investment entirely, it might make the overall programme more cost-effective. Grid investments typically take several years to deliver, whereas flexibility and efficiency measures can in some cases be deployed much more quickly. Efficiency reduces pressure on overall system size, while the case for flexibility as a near-term complement to infrastructure is more practical as it targets peak periods specifically. Eskom has drawn on demand-side measures to manage operational constraints while longer term investments are still planned, with Cape Town developing demand management programmes at the local level. Together, these approaches have helped avoid more expensive peaking capacity and have supported a more efficient system in the interim.

Participating residential, commercial and industrial consumers can see the cost savings

For participating consumers, the main benefits of demand flexibility are realised through cost savings. Estimating the potential impacts on consumer energy bills and distributional outcomes are highly context-specific. However, examples of existing cost savings provide an indication of the magnitude of cost benefits that consumers could receive by being flexible in their demand.

- Eskom has estimated that planned reform to ToU tariff structures could save representative households 5-27% depending on the size of the household.
- A company installing smart controls for water heating in South Africa has demonstrated savings of up to 30% on customers hot water heating bills.
- Eskom’s Distribution Demand Management Programme has an incentive of USD 187 000/MW for commercial users that meet reliability and eligibility requirements – equivalent to rates in demand response markets in the United States.
- A South African gold mine implementing demand response for compressed air systems lowered the peak electricity demand of the system by 17%, with an annual cost savings of USD 170 000 per year.
- Improved scheduling of high demand equipment, such as water pumps and air heaters, in another South African mine saved USD 20 000 over a 3-month period.

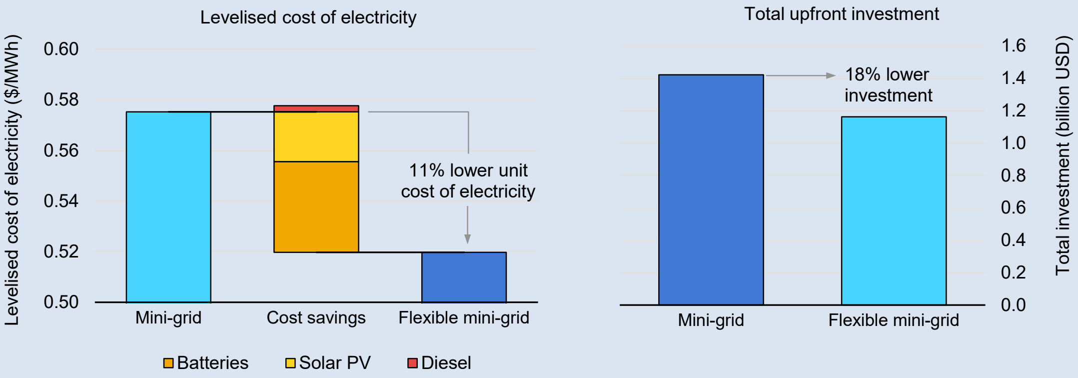
Facilitating affordability in remote areas through by enabling demand flexibility

South Africa has the highest electricity access rates in sub-Saharan Africa at 94% in 2023 – up from 78% in 2003 – supporting poverty reduction and social equity. Like the 600 million people in sub-Saharan Africa without access to electricity, a significant proportion of the remaining South Africans without access live in remote communities. For these communities, off-grid mini-grids or stand-alone systems, particularly solar PV and batteries, can often be the most cost-effective solutions.

As well as the financing, matching expected electricity demand to the size of the system is an important cost consideration, which can be managed through efficient appliances. Where settlements are large enough to support non-residential demand, such as schools, healthcare centres or water pumps (also called “anchor loads”), demand flexibility could help lower the cost of access for all users through ToU tariffs designed to incentivise demand when solar PV output is highest. In India, an initiative to install 10 000 mini-grids has included flexibility in its mini-grid design.

For remote, unelectrified settlements in South Africa, anchor loads could lower electricity costs for all users. IEA analysis shows the average cost of electricity could be reduced by around 11% through lower generation capacity. Given the capital-intensive nature of these technologies, investment requirements for these mini-grids could fall by 18%, potentially reducing the cost access to the approximately 500 000 households in South Africa that may be suitable for mini-grid solutions.

Levelised cost of electricity (left) and total investment (right) to electrify 500 000 remote households in communities with non-residential demand in South Africa with flexible and inflexible mini-grids, 2025



Notes: Solar PV = solar photovoltaics; USD/kWh = United States dollar/kilowatt hour. The left axis does not start at zero. Analysis assumes that non-residential anchor loads making up 20% of settlement demand could be made flexible with demand peak for these end users coinciding with solar PV output. Settlements suitable for mini-grids are defined as >50 km from the existing electricity network and with >100 households.

Source: IEA analysis based on data from Carbon Trust (2024) and the OpeN Source Spatial Electrification Toolkit (2025).

Chapter 4. Demand flexibility in transforming power systems: The case of Thailand, 2030

Pilot stage demand shifting for learning purposes

By 2030, many of the factors driving the need for system flexibility and the availability of demand flexibility will continue to develop. While supply-side flexibility measures will remain central for system operation, demand flexibility could play a growing role. In systems experiencing demand growth and structural changes, demand flexibility could moderate peak demand, helping the system adapt to varying operational needs and fuel price volatility. These pressures will further amplify the existing benefits to networks and consumers, widening the scope for their impact in many jurisdictions around the world.

Flexibility has the potential to help manage steadily growing electricity demand at the global level

The IEA STEPS scenario indicates that by 2030, electrification and the share of renewable energy in overall generation will continue to grow, leading to modelled short-term flexibility doubling in advanced economies and increasing by around two-and-a-half times in emerging markets and developing economies (EMDE).

Electricity demand growth globally to 2030 will likely be double from that of 2015-2020, with EMDE making up 80% of the growth. Industry and cooling will have a considerable effect on peak demand, which grows by 1 800 GW by 2035 in STEPS. Managing this strain on grids cost-effectively will be critical to affordability. The long lead times for new generation and networks mean that managing demand could increasingly complement supply-side investment.

More diverse and responsive power systems will be needed

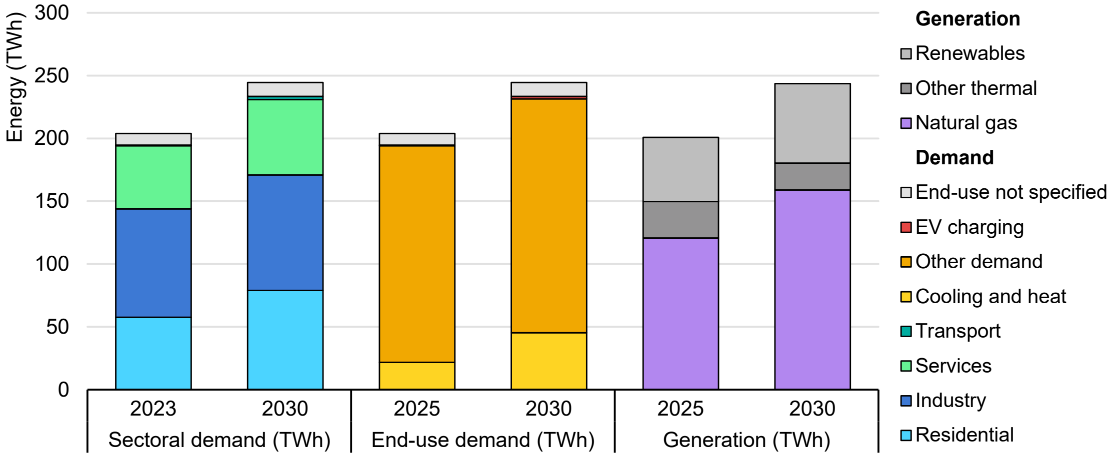
Ensuring an affordable and secure power system will be critical in all regions. Particularly in EMDE, demand growth, rapid electrification and rising shares of renewable energy are reshaping the electricity system. Meeting the growing need for system flexibility with a more diverse portfolio of technologies could improve the resilience of the system and better insulate it from fuel price shocks.

Growth in demand response ready appliances could enable demand flexibility to help diversify the electricity system, providing more regular demand shifting alongside less frequent peak shaving. Uptake of smart meters would support flexibility aggregators to combine flexibility across households and businesses. Moving towards a more efficient, affordable, decentralised and responsive power system will also require reform. The need for the right response, at the right time and in the right place, provides a clear signal that demand-side resources can help manage the power system.

Thailand's power system and demand flexibility resource

Electricity demand growth in Southeast Asia is a major driver of global demand, with the average annual growth of about 5% since 2020 and is expected to continue in the coming years. The pressures of growing demand and renewables integration are particularly evident in Thailand. The largest electricity demand sector is industry (86 TWh), responsible for 44% of total electricity demand, followed by the residential sector (58 TWh) with 30% of the total, services (50 TWh) with 26% and transport (0.5 TWh).

Annual electricity demand, end use demand and generation output for Thailand, 2025 and 2030



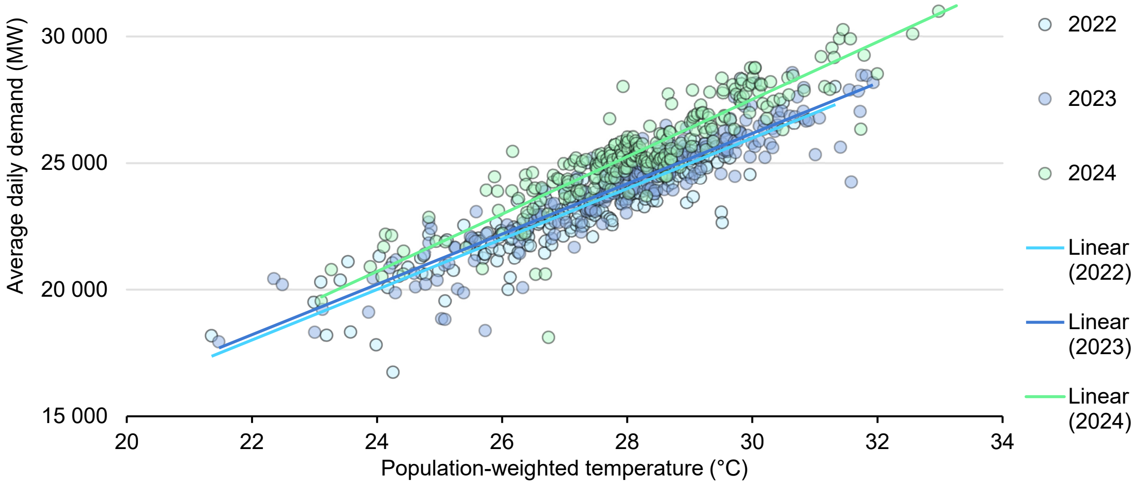
IEA. CC BY 4.0.

Notes: EV = electric vehicle. "Heat" in "cooling and heat" refers to hot water and industrial heating processes; "Other thermal" includes coal, diesel and fuel oil; and "Renewables" includes hydro, solar PV, wind, energy from waste, biogas, and biomass.
Sources: IEA (2025), Energy End-Uses and Efficiency Indicators; Thailand, Ministry of Energy (2026).

Continued growth in electric vehicle (EV) sales could increase transport electricity demand by four to six times by 2030, potentially posing challenges for power systems if unmanaged. The share of electric cars in total vehicle sales increased to about 22% in 2025, almost double year-on-year. Managing the potential impact on peak demand will be crucial to avoid problems on the grid.

Driven by rising appliance ownership and increasing temperatures, cooling could also make up a large part of the expected demand growth to 2030, with a potential doubling of demand. In the residential sector, an estimated 30% of demand comes from space cooling. Annual cooling degree days (i.e. days when outdoor temperatures are above the level where buildings typically need cooling) in Thailand are already among the highest in the world. With climate change, such weather events have increased in recent years. At today's AC ownership levels, each degree increase in average temperature drives a 1 GW increase in daily peak demand. Improving the efficiency of cooling equipment and buildings could reduce overall electricity demand growth.

Peak electricity demand versus average temperature in Thailand, 2022-2024



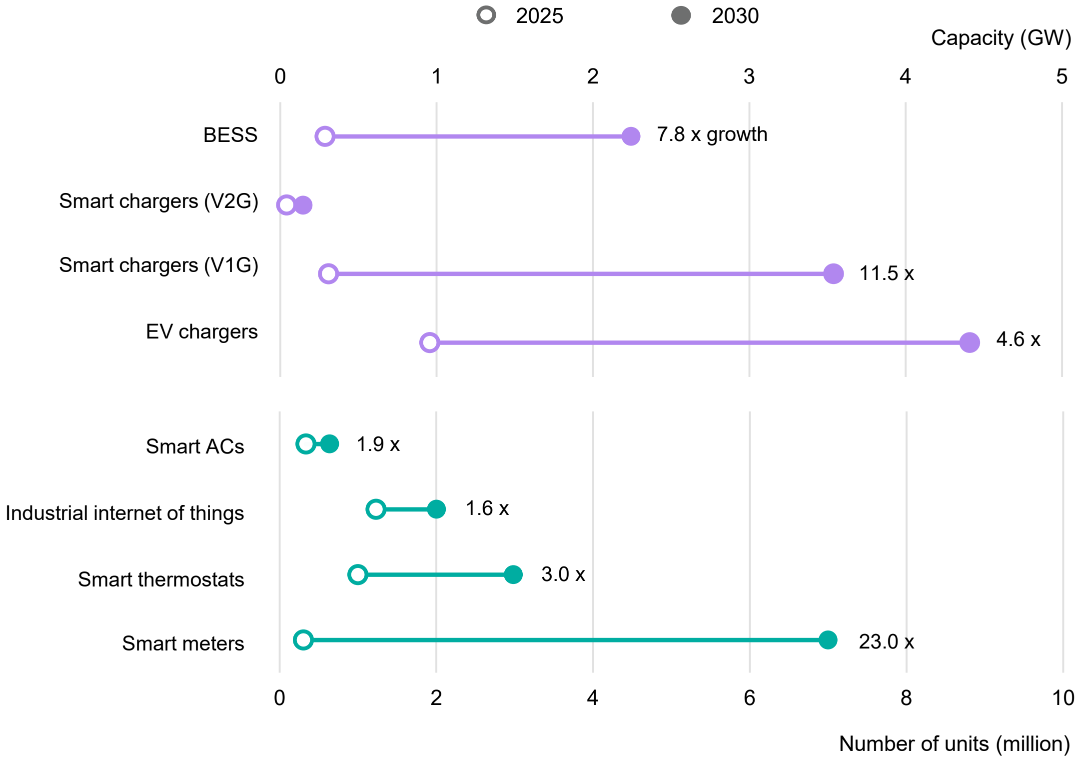
Sources: IEA (2026), Real-Time Electricity Tracker; IEA (2026) Weather, Climate and Energy Tracker.

Renewable output is expected to grow from a strong base in Thailand. Around a quarter of electricity generation is currently derived from renewable sources (mainly hydro and biomass), with variable renewables (mainly solar PV) contributing around 5%. Solar PV deployment is expected to continue growing and, by the end of the decade, reach about 8% of total generation. While this would move Thailand towards phase 2 of Renewables Integration, this level of integration can generally be managed through operational improvements and use of existing infrastructure, greater solar generation could widen the gap between total and net demand. This would create steeper evening ramps with solar output falling and cooling demand rising, as has been seen in India, underlining the need for flexible resources that can respond quickly to changing system conditions.

Smart technologies could enable wider participation in flexibility

The uptake of smart technologies will influence the availability of demand flexibility. Delivering reliable and predictable load shifting requires devices that can be remotely controlled or programmed in advance to manage end uses, subject to consumer consent. However, this may create tensions between the needs of aggregators to deliver grid services and the energy service expectations of consumers. Improved understanding of the factors that influence participation, such as when users might choose to override flexibility events, would help inform programme design and implementation. As the number of interconnected devices increases, cyber security considerations may also become more prominent.

Modelled growth rates for selected flexible technologies in Thailand, 2025-2030



Notes: ACs = air conditioners; BESS = battery energy storage system; EV = electric vehicle; V1G = managed (smart) one-directional EV charging; V2G = vehicle-to-grid (bidirectional smart charging). Technologies are shown as a total across residential, commercial and industry sectors, except for industrial internet of things. Growth rates for technologies are shown for all except V2G given the extremely low starting base in 2025. Smart chargers (V1G and V2G) are a subset of EV chargers – the figure shows the total installed charger capacity, and not the concurrent demand of charging.

Source: IEA analysis based on data from Guidehouse (2026).

A key technology that is expected to show the strongest growth in the coming years is smart meters. The Metropolitan Electricity Authority, which covers the Bangkok metropolitan area, aims to install 4.3 million units by 2032 for customer types. This strong growth is expected to continue in residential, commercial and industrial sectors. The Energy Policy and Planning Office has developed a system to monitor smart grid implementation progress.

Alongside smart metering, wider deployment of industrial internet of things technologies is projected to nearly double by 2030. Improved monitoring and control of industrial processes would allow businesses to adjust electricity use in response to system needs. This could be particularly important in Thailand, where industry accounts for almost half of annual electricity demand, and less energy-intensive industrial processes have significant potential for load shifting.

With the overall increase in cooling demand, market data projections suggest there will also be strong growth in smart ACs, rising by 90%, and in smart thermostats at 200%. Smart AC controls have already featured in Thailand in a 2019 pilot for the office buildings of the Metropolitan Electricity Authority, the success of which saw the technology expand to two further locations.

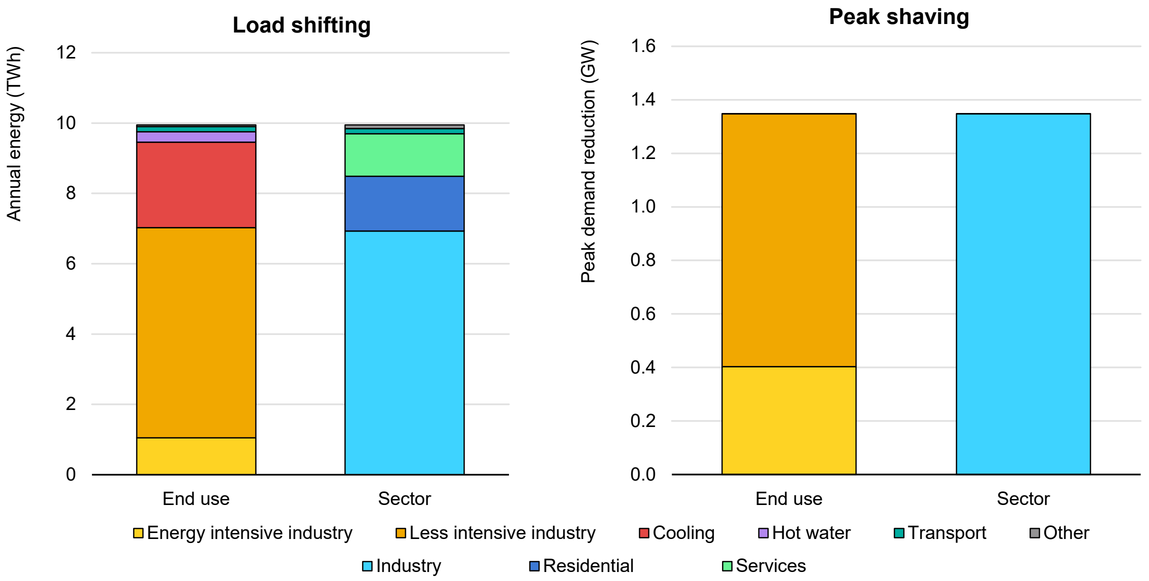
Although the absolute share of EVs in total demand will still be relatively low in 2030, it will likely experience significant growth, with the number of unmanaged chargers increasing nearly five times. The grid impacts could be mitigated by smart charging to shift demand away from peak periods. Thailand is already exploring such opportunities through regulatory sandbox programmes, which relax regulations under controlled conditions to build understanding of how to address regulatory barriers. This has enabled the Electricity Generating Authority of Thailand and other stakeholders to test EV smart charging under controlled conditions, helping to inform future market and regulatory development.

Technology uptake and participation across sectors will shape future flexibility resource potential

IEA analysis indicates that less energy-intensive industries could play a central role in providing demand flexibility in Thailand, provided there is enough uptake from industry. Sectors such as machinery, food processing, tobacco and textiles account for around half of industrial electricity demand and are often more technically able to adjust consumption without disrupting production compared to energy-intensive industries. As a result, these sectors could provide more than 70% of the industrial flexibility potential available by 2030, through both load shifting and peak shaving.

The residential and services sectors also offer significant flexibility potential, with cooling and water heating providing around 2.7 TWh of demand that could be shifted. Although not as significant as industry, thermal loads can often sustain longer duration shifts if combined with efficient building fabric, allowing demand to move further from periods of high system costs. This potential uptake will also depend on regulatory frameworks, market incentives and the deployment of other enabling technologies. As well as technology uptake, this flexibility will also depend on consumer confidence. Social acceptance of connectivity and participation can vary by country and demographic groups, so programmes failing to consider these factors might not achieve the modelled potential.

Technical demand flexibility potential in Thailand by sector and by end use for load shifting (left) and peak shaving (right), 2030



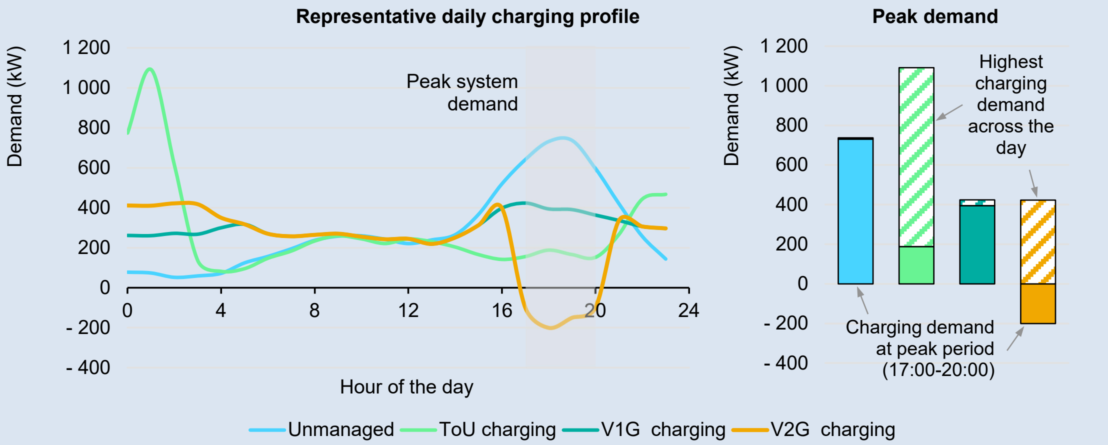
Notes: Other end uses include residential and commercial cooking, lighting, refrigeration, brown appliances; desalination; and data centres, which are currently considered less suitable in terms of flexibility.
Source: IEA (2025), World Energy Outlook.

Policy frameworks are key to aligning EV charging with system needs

The electrification of transport presents both a challenge and an opportunity. While unmanaged charging could increase peak demand and infrastructure costs, smart charging could provide flexibility. This impact will depend on the charging arrangements and incentives available.

- **Unmanaged charging:** Vehicles begin charging immediately when plugged in, often creating the greatest network strain when it coincides with peak demand.
- **Time-of-use (ToU) charging:** Charging is shifted through static off-peak tariffs, but this could create peaks if vehicles begin charging at the same time.
- **Smart charging (V1G):** Charging is automatically adjusted based on system conditions or dynamic prices, which can spread charging across the day.
- **Vehicle-to-grid (V2G):** Bi-directional chargers allow EV batteries to return electricity to the grid, subject to consumer preferences and vehicle availability.

The impact of unmanaged charging, V1G charging and V2G charging on peak demand from the representative charging of 1 000 vehicles



Notes: ToU = time of use; V1G = one-directional EV charging; V2G = vehicle-to-grid (bidirectional charging). The magnitude of peak demand will also vary with the charging speed.

Source: IEA (2023), Electric Vehicle Charging and Grid Integration Tool.

Policy frameworks play a central role

Consumer participation can be influenced by tariffs, market signals and access to enabling technologies. Most EV flexibility could be delivered through managed V1G smart charging- while V2G may provide additional flexibility, many of the benefits could be realised without bi-directional charging. Policies to support dynamic pricing, interoperability, data access and aggregator participation could help ensure that growing EV fleets support a more efficient and flexible power system.

The value of demand flexibility in Thailand in 2030

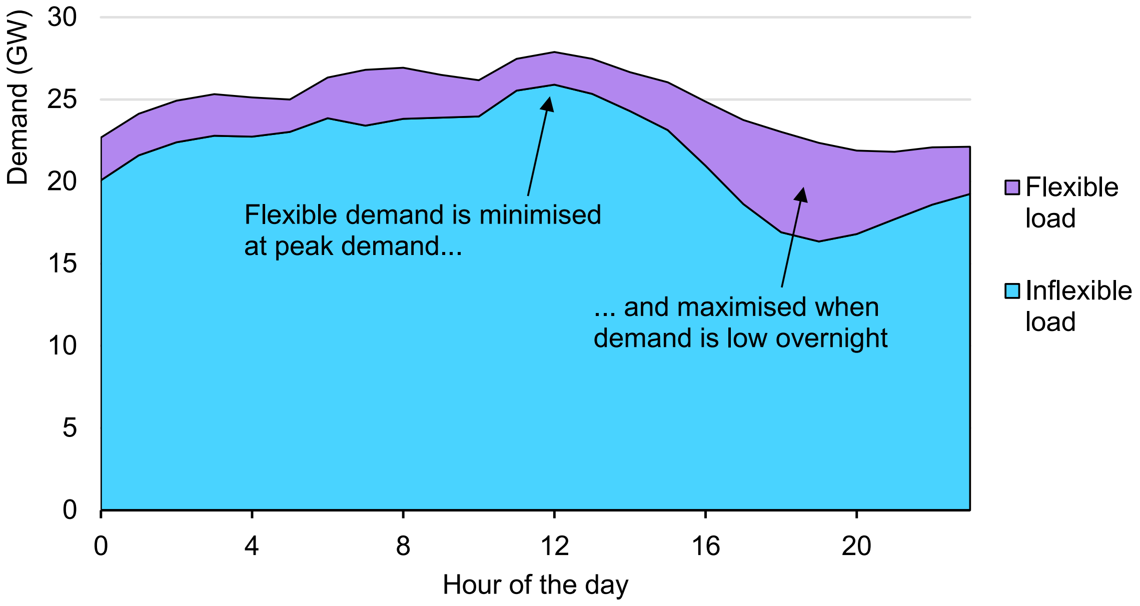
In Thailand, demand flexibility has the potential to support an efficient and affordable transition to a more dynamic power system. By shifting electricity demand could reduce peak demand, improve asset utilisation and lower investment needs. The value of flexibility is therefore expected to grow as the power system becomes more dynamic with further renewable deployment.

To assess these impacts, a model has been used to quantify the potential contribution of demand flexibility developed by 2030 (see Annex). Given uncertainties around technology uptake, regulations, consumer participation and future system needs, the IEA has developed a Base flexibility case representing a concerted push towards demand flexibility, alongside High flexibility (+20% shifting and shedding potential energy) and Low flexibility (-15%) scenarios.

Cheaper generation during the night is the main driver of shifting patterns

By 2030, natural gas will likely continue to provide around two-thirds of electricity generation. Renewable output will be fully utilised, meaning that spot electricity prices will continue being driven by demand patterns rather than periods of excess renewable generation. As a result, the principal opportunity for flexibility would be shifting demand from daytime and evening peaks to lower cost overnight hours.

Potential demand curve optimisation by load shifting to overnight, Thailand, 2030



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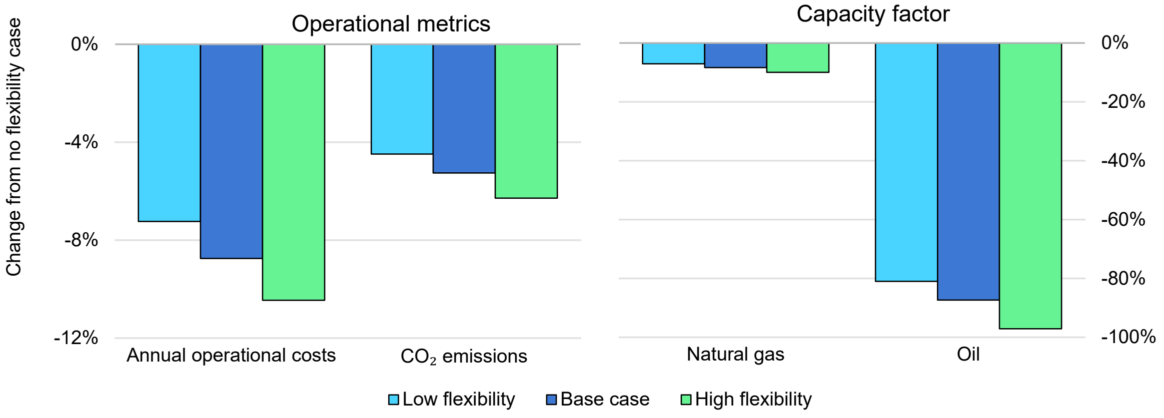
While system-wide flexibility would likely be driven by daily price differences, local energy markets could incentivise demand shifting to periods of renewable generation. These arrangements allow organisations to trade locally generated renewable electricity with nearby consumers, helping to increase renewable utilisation, reduce network constraints and lower costs for participants. Thailand has already tested local energy markets through its regulatory sandbox programme. The first phase, launched in 2019, supported eight peer-to-peer (P2P) energy trading projects. While still limited in scale, these projects demonstrate how local market arrangements could complement broader flexibility measures and support renewables integration at the distribution level.

Demand flexibility offers the potential to lower the operating costs of the power system

IEA analysis suggests that the modelled demand flexibility could reduce the operating costs of Thailand's power system by around 9%, rising to almost 11% in the High-flexibility scenario. These savings are achieved primarily by lowering more expensive fossil fuel generation at peak demand, subject to other system reliability requirements. Although the largest impact is seen for oil-fired peaking generation, it contributes less than 0.1% of annual electricity generation. Flexibility also lowers reliance on natural gas generation, however coal is less affected, as one of the lowest-cost dispatchable generation sources in the system.

A comparison of operational metrics and capacity factors for modelled cases of demand flexibility in Thailand, 2030



Notes: Coal has been excluded given the limited difference between the flexibility scenarios. Operational costs include (in order of importance) fuels costs, ramp costs, variable operations and maintenance costs, as well as startup and shutdown costs.

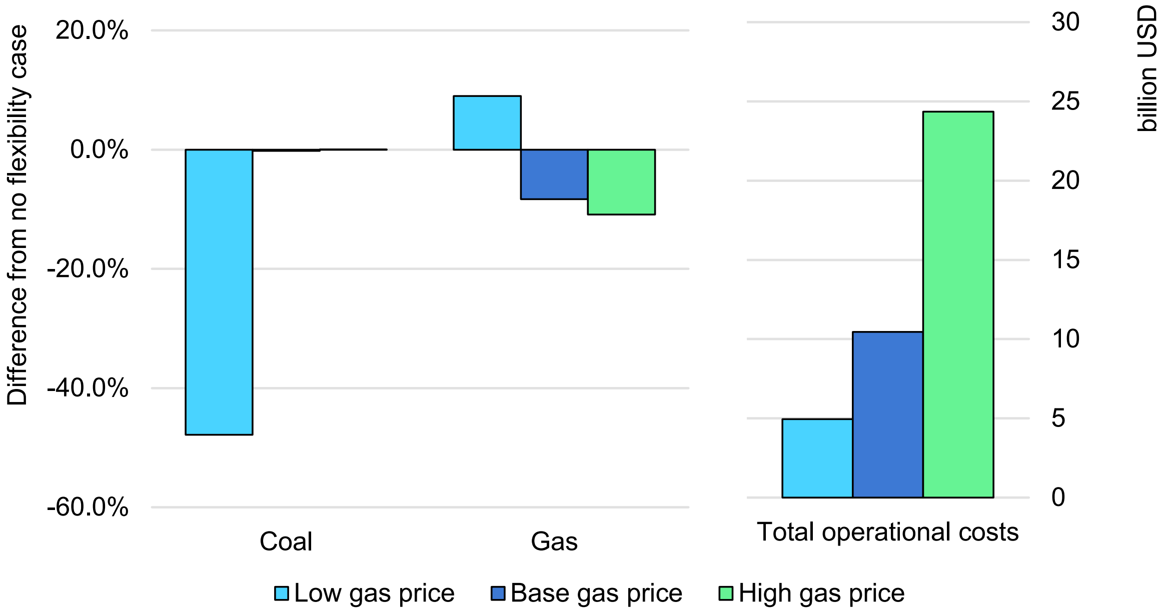
Beyond cost savings, demand flexibility could also support a reduction in carbon dioxide (CO_2) emissions. IEA analysis indicates that emissions could be reduced by 4-6% across the modelled scenarios. The reduction is smaller than the decline in operating costs because flexibility primarily displaces natural gas generation, rather than higher emissions coal generation. These reductions could help accelerate progress towards Thailand's decarbonisation objectives without additional investment in renewable generation capacity.

The results also indicate that the value of demand flexibility remains consistent with more flexibility on the system. In practice, this means that early investments and pilot projects can deliver meaningful benefits. Rather than being dependent on large volumes of participation, flexibility could provide value across a range of system needs, suggesting that first-of-a-kind projects can generate substantial insights and benefits despite their size. Whether this flexibility could be realised in the next five years will depend on the costs of enabling technologies, consumer participation and market arrangements relative to other flexibility options.

Flexibility cost savings could help insulate against fossil fuel price shocks

Although approximately half of Thailand's natural gas supply is produced domestically, the remainder is imported, leaving electricity costs exposed to movements in international fuel markets. Demand-side measures like flexibility and efficiency on the other hand are an indigenous and controllable resource that all countries can develop to strengthen resilience to price fluctuations.

Impact of natural gas prices on the operating costs of the power system in Thailand, 2030



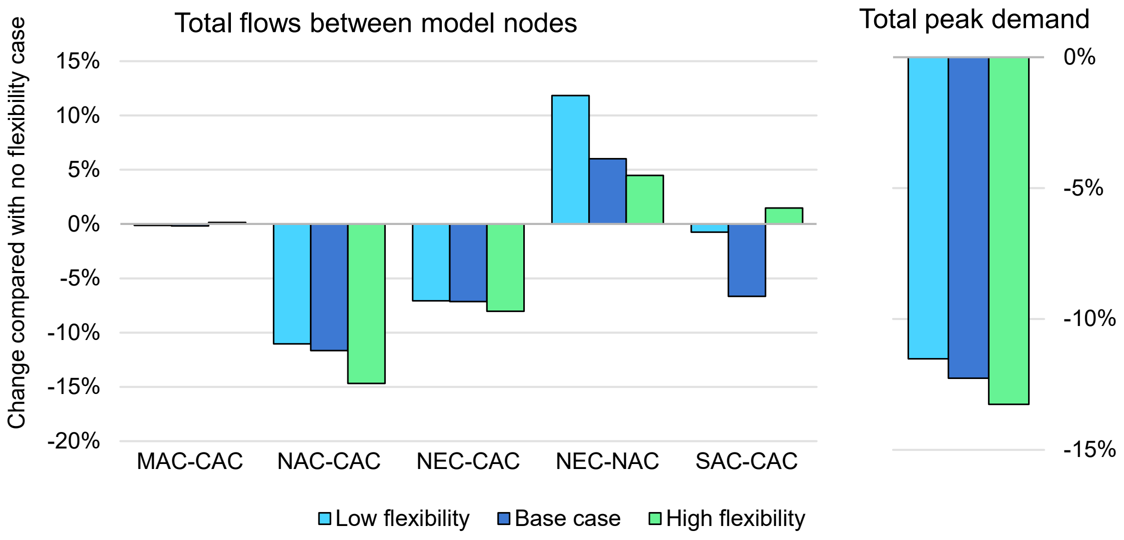
Notes: USD = United States dollar. Low gas price assumes annual gas prices from 2020, averaging USD 4 per gigajoule (GJ); High gas price assumes prices from 2022, averaging USD 32/GJ.

IEA analysis shows how the value of flexibility could be elevated during price shocks. Comparing fuel prices in 2020 and 2022, higher gas prices resulted in operating costs almost five times greater, or just over double the base gas price scenario, although the value is lesser under a low gas price scenario. The extent of this benefit would need to be assessed against the costs to implement flexibility measures. However, unlike imported fuels, many of these costs are incurred domestically and may therefore be more predictable and controllable over time.

Flexibility could unlock capacity in existing infrastructure

IEA analysis suggests that demand flexibility could reduce Thailand's national peak electricity demand by up to 13% in 2030. The impacts vary by region, from a slight increase in peak demand for the Central region (CAC - see Annex) to a more significant reduction in the Metropolitan Bangkok region (MAC). This reflects both the location and type of flexible demand available, with industrial consumers currently providing the largest source of peak reduction potential.

Changes in transmission flows and peak demand under different levels of demand flexibility in Thailand, 2030



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Notes: CAC = Central (region of Thailand); MAC = Metropolitan Bangkok; NAC = Northern; NEC = North-Eastern; SAC = Southern. The names of the nodes are as provided by the Electricity Generating Authority of Thailand (see the Annex for more details).

Beyond reducing peak demand, flexibility could improve the utilisation of existing network infrastructure. In several regions, demand flexibility reduces electricity flows across transmission corridors, lowering line loading and potentially allowing additional demand to be accommodated on the same network capacity. However, the impacts vary by location, with some lines showing larger benefits than others, highlighting the need for regional assessments to address co-ordination risks. Overall, greater levels of demand flexibility are associated with lower network flows, indicating that flexibility could help make better use of existing infrastructure and support continued electrification at lower cost.

Pilot projects have already demonstrated consumer cost savings of up to 70% if combined with renewables

Even at the pilot stage, demand flexibility programmes can benefit participating households and businesses. These can arise through lower electricity bills, direct participation payments or greater use of locally generated renewable electricity. Businesses in Thailand were compensated USD 0.04-0.08/kWh (up to 70% of average industrial electricity prices of USD 0.11/kWh in 2024) for avoiding peak demand periods, as well as availability payment of USD 16.4/kW/year.

Examples of pilot projects in other regions of the world include:

- Households in India provided with Wi-Fi connected AC switches were rewarded USD 0.06-0.30/kWh for peak events (up to half of the average residential electricity price of USD 0.6/kWh in 2024) with a 23% override rate.
- Under the first phase of IEA Digital Demand-Driven Electricity Networks (3DEN) initiative, pilot projects demonstrated how digitalisation can create value for both households and businesses. In Brazil, 100 households, equipped with rooftop solar PV, battery storage, smart meters and Internet of things- enabled energy management systems, reduced electricity bills by 60-70%, while also decreasing annual electricity consumption and improving resilience during outages.
- Under the first phase of IEA Digital Demand-Driven Electricity Networks (3DEN) initiative, pilot projects demonstrated how digitalisation can create value for both households and businesses. In Brazil, 100 households, equipped with rooftop solar PV, battery storage, smart meters and Internet of things- enabled energy management systems, reduced electricity bills by 60-70%, while also decreasing annual electricity consumption and improving resilience during outages.

Unless programmes include the installation of dedicated hardware or control devices, participation in later stages is limited to generally better-off households that already have a higher share of shiftable demand. Fuel poor households in the United Kingdom, for example, were provided with solar PV and home batteries. Such interventions enabled a 60% reduction in their electricity demand from the grid, with many able to be net exporters of electricity in the summer months.

Chapter 5. Demand flexibility in a future power system: The case of Ireland, 2035

Flexibility as a core system resource

By 2035, increasing electrification, changing climatic conditions and evolving patterns of technology use could reshape both the scale and timing of electricity demand. At the same time, continued deployment of renewable generation would increase the need for system flexibility, increasing the value of demand flexibility in supporting reliable and cost-effective system operation.

Growth in renewables and grid developments will increase the value of flexibility

In many world regions by 2035, strong growth in renewable generation is set to continue, supported by national targets for power sector decarbonisation. Since 2010, prices for solar PV, wind turbines and battery storage have fallen by 70-90% and could fall a further 10-40% by 2035. This makes renewables among the cheapest sources of electricity, though there are other integration costs discussed below. Economies of scale combined with supportive policy packages has led to wind and solar PV making up the majority of new generation in the last five years. While renewables can reduce emissions and fuel imports, their weather-dependent output increases the need for flexibility resources to manage shifting net demand patterns. The likelihood of negative net load periods, where renewable output exceeds electricity demand, has increased in many regions at higher as well as lower stages of renewables integration.

Although the wholesale price of renewable generation is low, it must be considered alongside additional grid costs. By 2030, to meet national climate targets, annual grid investments need to nearly double to USD 600 billion, including the cost of maintaining, replacing and modernising existing capacity. For the roughly 30 million kilometres of new transmission and distribution network capacity required by 2035, multi-year planning and lead-in times would mean that grid investment decisions are needed today. The scale of the investment required has also been affected by rising unit costs for grid infrastructure. Minimising the scale of this investment presents opportunities to reduce the pressure on affordability for consumers.

Electrified and digitalised demand could unlock new flexibility potential

The growth and evolution of electricity demand will likely continue in parallel to growth in renewables and grid developments. In emerging markets and developing economies (EMDE), peak electricity demand in STEPS will increase by around 50% with rising living standards and expanding floor spaces. In advanced economies, a 20% increase in peak demand will come from sectors such as heating, electrified transport, and larger energy users like data centres.

Digitalisation is a key factor that could differentiate demand flexibility in 2035. It could enable the aggregation of smaller demand users compared with today's programmes, which mainly focus on large energy users. The widespread adoption of predictive models, today being used largely in smaller pilot projects, will allow real-time demand to be adjusted in response to grid price signals. Grid operators could then use demand flexibility as a daily system optimisation tool.

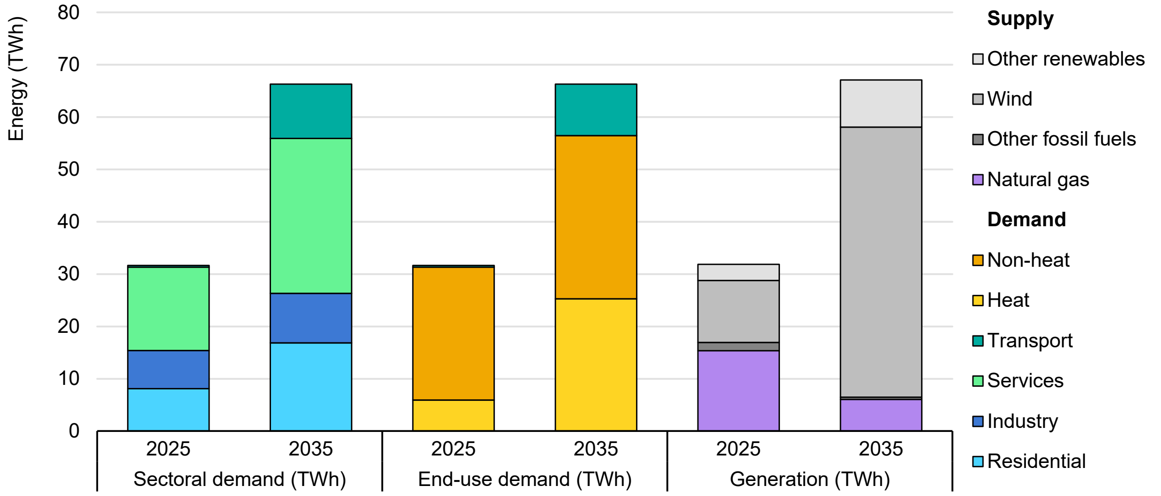
Ireland's power system and demand flexibility resource

Ireland's approach to decarbonisation plans has been discussed in recent IEA publications, with a broad overview in the Energy Policy Review in 2024 and a focus on energy security in Powering Ireland's Energy Future in 2025.

Meeting policy ambitions in full could double electricity demand in Ireland by 2035, with around 85% of the increase from transport and heating. Heating demand could more than triple, while transport could emerge from a near-zero base to almost one-fifth of total electricity demand. This would transform the composition of electricity demand, with heating and transport making up nearly half of annual demand by 2035. Although there is uncertainty in demand projections among the governmental organisations and network operators, all expect significant growth. The extent of this growth will depend heavily on efficiency progress, both in terms of retrofit and new technologies, and presents opportunities for demand flexibility to enable a more cost-effective energy transition.

Ireland has ambitious power sector decarbonisation goals, targeting around 88% generation from renewables by 2035 in the IEA's Adapted Transition Pathway. This would take it to phase 5 out of the 6 phases of Renewables Integration, meaning there would be large surpluses of renewable output over the year. Both long- and short-term power system flexibility will be crucial to managing this surplus. Alongside traditional supply-side technologies, digitalisation and electrification could help provide this flexibility.

Annual electricity demand, end-use demand and generation output for Ireland, 2025 and 2035



Note: “Heat” includes heat pumps, hot water and industrial processes; “Other renewables” includes coal and oil; “Other fossil fuels” includes hydro, solar PV, biofuels, and energy to waste.

Sources: IEA analysis based on IEA (2025), Energy End-uses and Efficiency Indicators; IEA (2025), Real-Time Electricity Tracker; EirGrid (2023), Tomorrow’s Energy Scenarios; Directorate-General for Energy (2016), Mapping and analysis of the current and future (2020-2030) heating/cooling fuel deployment (fossil/renewables); Electricity Supply Board (2025), Demand data by sector and end use.

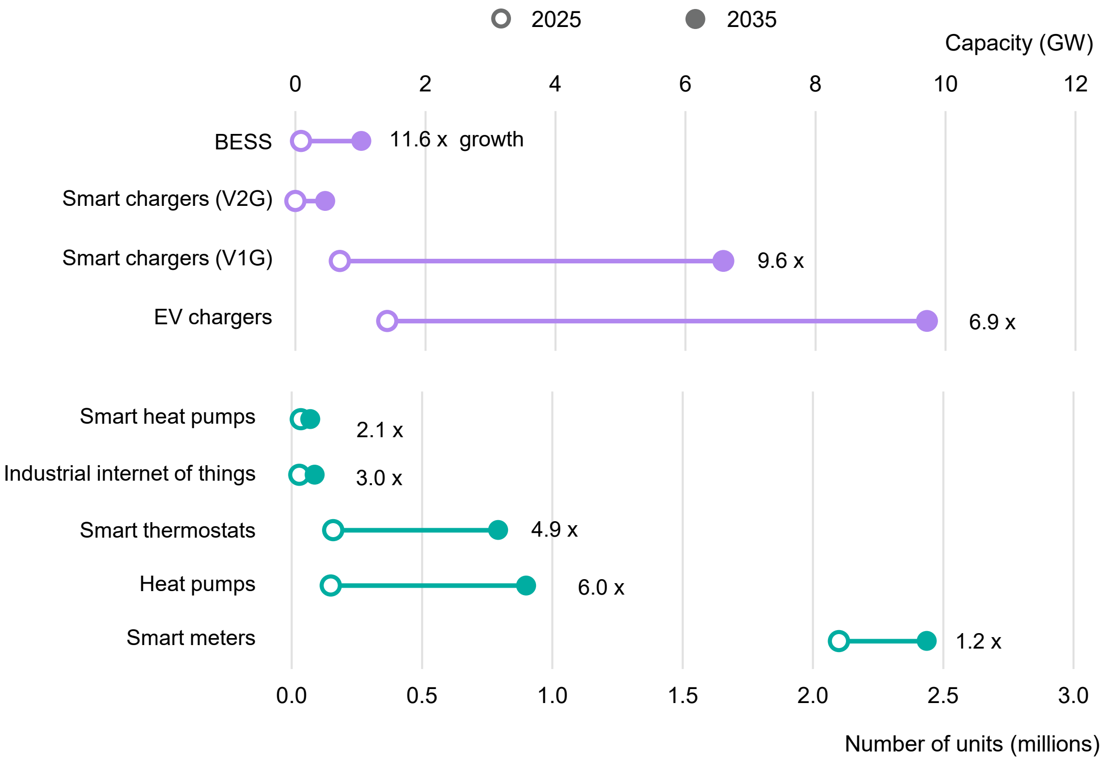
Increased electrification could however worsen grid congestion if unmanaged. Similar to many regions, investment in grids and integration capacity in Ireland has not kept pace with the renewables, leading to curtailment levels of 7-10% in recent years and congestion costs tripling from 2015 to 2025. Growth in other demand, such as data centres in the Greater Dublin area, has also led to local network stress and difficulty in connecting new demand. Demand flexibility could potentially address these issues, with other benefits to consumers and the system.

More renewables will likely lead to lower spot prices, which can help insulate against fossil fuel price spikes. Spot prices in countries like Spain were less affected by recent fossil fuel price shocks due to greater shares of renewables. Electrification and smart appliances could allow consumers to benefit from these low-price periods. As of 2024, Ireland had around 80% residential and industrial smart meter deployment. Smarter timing of demand could allow consumers to take better advantage of the system while also helping to address power system challenges.

Digitalisation, AI and electrification are expanding flexibility opportunities

Expected growth in electricity demand will coincide with increasing deployment of digital and interconnected technologies, which are central to unlocking demand flexibility at scale. More advanced automation, optimisation algorithms and AI-enabled energy management systems could improve the ability of flexible resources to respond to system needs while minimising impacts on consumers. For Ireland, uptake of flexibility-enabling technologies will vary according to technological maturity and supportive policy frameworks. With increasing connectivity, cyber security considerations are likely to become more prominent, requiring co-ordinated approaches to risk management across connected devices.

Modelled growth rates for selected flexible technologies in Ireland, 2025-2035



Notes: BESS = battery energy storage systems; EV = electric vehicle; V1G = managed (smart) one-directional EV charging; V2G = vehicle-to-grid (bidirectional smart charging). Technologies are shown as a total across residential, commercial and industry sectors, except for industrial Internet of things. Growth rates V2G are not given the extremely low starting base in 2025. Smart chargers (V1G and V2G) are a subset of EV chargers – total installed charger capacity is shown, and not the concurrent demand of charging.

Source: IEA analysis based on data from Guidehouse (2026); European Heat Pump Association (2025), Heat Pump Market Report.

The most mature technology in Ireland is smart meters due to the decades long European Union (EU) push for their deployment. As of 2025, there were just over 2 million such meters deployed in households and businesses (around 80% coverage) in Ireland, with modest growth expected by 2035.

Devices controlling demand end uses will see more significant growth, including numbers of smart thermostats growing five times and industrial internet of things growing three times. Combined with advanced control algorithms and compatible end-use technologies, they could unlock large cost savings with minimal investment in additional hardware. These devices and their use cases are well established, but lack sustained policy support like smart meters. Starting from a smaller base, their uptake will likely be supported by the cost savings that they can generate for households and businesses.

Supported by electrification plans and strong policy packages, controllable end-uses will likely see the greatest growth. As is the case for other regions, EVs are a key feature of Ireland's decarbonisation plans, with EV sales in Ireland increasing by around 500% between 2020 and 2024. By 2035, the capacity of EV chargers could increase a further seven times. Combined with access to dynamic tariffs, it is expected that two-thirds of chargers could be smart chargers (e.g. V1G), allowing daily optimisation of charging costs, with a smaller proportion being able to return energy to the grid (V2G), which could offer greater cost savings, potentially reducing grid overload during peak periods by up to 20% with AI-enabled grid integration.

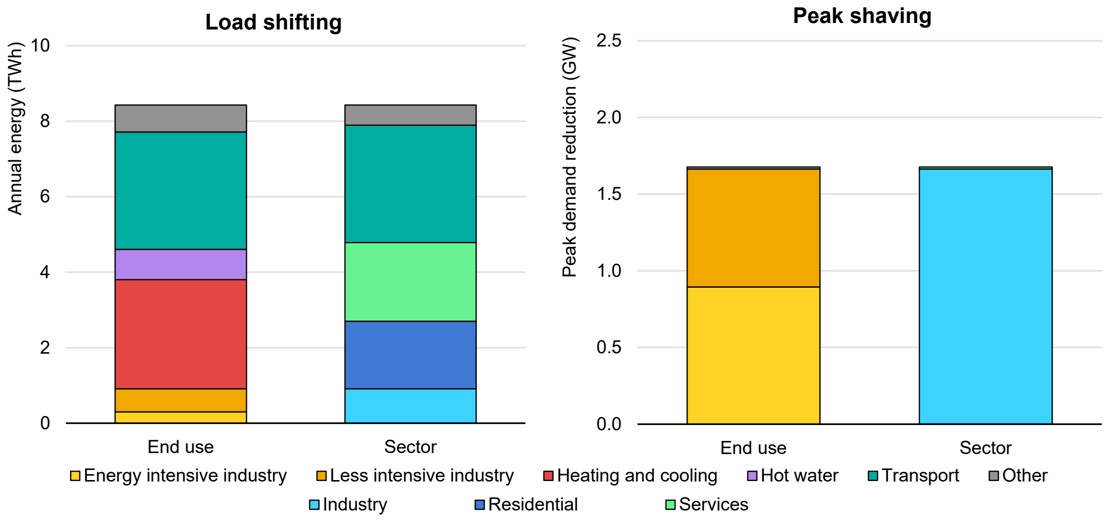
Heating and transport offer the most demand shifting potential, but industry still dominates peak shaving

IEA analysis of the flexibility potential for Ireland centres on the combination of digital technology uptake and the shiftability of demand end uses. Although heating demand in 2035 could be two-and-a-half-times larger than that of transport, transport has around three times higher flexibility potential, meaning that transport can offer significantly higher load shifting at just over a third of the 8.5 TWh of technically shiftable demand. Given the potential cost savings, minimal disruption to energy services and extensive digitalisation, the uptake of this flexibility is likely to be the highest relative to other end uses.

Uptake of digital controls could unlock around 3.9 TWh of demand shifting from residential and commercial buildings, nearly half the total flexibility potential. Most of this potential arises from space heating (2.9 TWh, 34% of the total potential) and water heating (0.8 TWh, 10%), where thermal inertia could allow energy use to be shifted with limited impact on comfort or service levels. Commercial buildings and households contribute similar amounts of flexibility overall, while household appliances could also contribute around 0.5 TWh (6%). As electrification and digitalisation expand, efficient grid-interactive buildings could become an increasingly important source of system flexibility.

Industry continues to play a significant role. Although the share of load shifting potential falls to 11% with growth in other emerging technologies, the absolute volume of industrial flexibility remains substantial. Greater digitalisation, connectivity and advanced control systems could enable production schedules to respond more dynamically to electricity prices and system conditions while maintaining operational performance. Industrial consumers also provide all contracted peak shaving due to their ability to reduce demand quickly if required.

Annual technically flexible demand in Ireland by shifting and peak shaving for different sectors and end uses by load shifting (left) and peak shaving (right), 2035



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Notes: “Other” includes non-heating, hot water building appliances, data centres, agriculture and district heating. The maximum technically shiftable demand is shown, which does not imply that this demand would be economically feasible.
Source: IEA (2025), World Energy Outlook.

As demand flexibility increasingly relies on aggregating smaller residential and commercial consumers, realised flexibility may depend on factors such as participation rates, consumer preferences and uptake of controllable technologies. These factors could influence the extent to which the technical potential identified in this analysis can be achieved in practice.

The value of demand flexibility in Ireland by 2035

The potential impacts of demand flexibility on security and affordability can be quantified using the power system model described in the Annex. As an expanding sector, there is inherent uncertainty as to how much flexibility could be available due to varying technology uptakes, regulatory environments, consumer behaviour and system demands for flexibility. To understand how the system value could evolve in relation to these drivers, the IEA has developed a Base flexibility case representing a concerted uptake of demand flexibility, as well as High (+20% shifting and shedding technical potential) and Low (-50%) scenarios. Ultimately, the appropriate amount of flexibility will be determined at the national level through the recently approved EU flexibility needs assessment methodology.

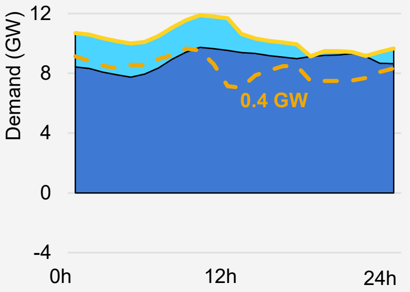
Flexibility shifts load to periods of higher renewable generation output

Comparing different days of net demand can demonstrate how different balances of demand and renewable generation can activate flexibility. In all the modelled cases below, flexibility alters the current Irish demand curve, with twin mid-morning and early evening peaks. There are clear trends like increased midday demand from greater solar PV output, or overnight EV charging, but the general correlation of flexible demand activation with renewable output could make it much more variable. For a near-decarbonised Ireland, with high shares of wind, these hourly swings could be significant, as low net load days show. It introduces some complexity in terms of balancing the system, which would need to be addressed by service providers and the automation of shifting in response to market signals.

Demand flexibility responds to changing system conditions and the availability of renewables in Ireland, 2035

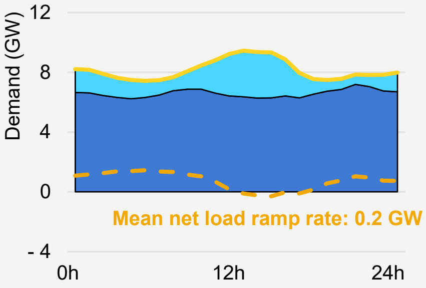
On an average day, solar PV and EV charging are key drivers.

Flexible demand activates at midday when solar PV output is highest and prices are lowest, though this will vary seasonally. Flexible load is minimised at morning and evening, with an increase overnight for longer duration, keeping the average net load ramp rate low at 0.2 GW.



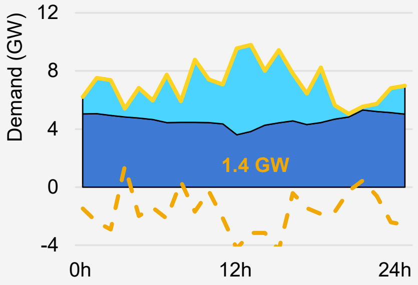
On a low renewable output day, flexibility avoids the peaks.

Without clear, low-cost periods from renewable output, demand is shifted to overnight and morning periods when demand and prices are lower. The slight peak of renewable output at midday leads to higher net load ramping of 0.4 GW.



On a high renewable output day, shifting follows this generation.

Net load is negative most of the day, with extremely low spot prices. Large swings in shifted demand mean a much higher net load ramp of 1.4 GW. Here, the shifting behaviour is more variable with the fluctuations in generation and near zero prices.



▬ Non-flexible load
▬ Flexibile load
– – Net Load
— Total load

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Notes: Solar PV = solar photovoltaics. Flexible load includes load shifting and load shedding. Zero or near-zero prices cause volatility in the flexible load on a low net load day.

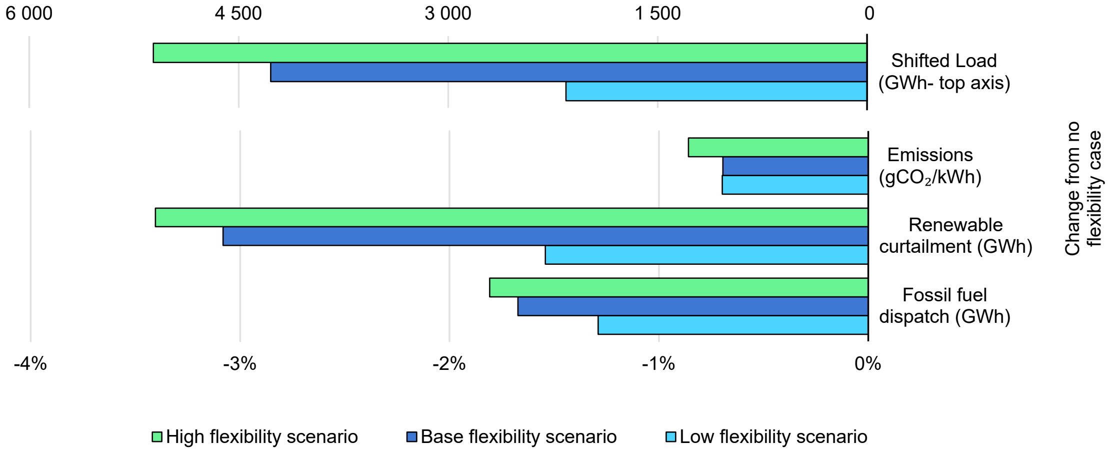
Demand flexibility in Ireland could lower renewable curtailment, fossil fuel dispatch and CO_2 emissions

Today, Ireland depends on largely imported natural gas to provide 60% of its annual generation. Import dependence will likely increase with plans to ramp down domestic production. Therefore, the best way to reduce import dependency and improve energy security will be through flexibility and efficiency measures.

The modelled Base flexibility case demonstrates clear benefits to energy security. Shifting demand away from periods of fossil fuel generation to locally produced renewables lowers fossil fuel dispatch by 1.7%, renewable curtailment by 3.1% and emissions by 0.7%. Relative to activated flexibility over the year, the potential is more significant, with 4 300 GWh of flexibility making use of 540 GWh of otherwise curtailed generation – the annual demand of 90 000 households in 2025.

The marginal, or per-unit, value of this flexibility varies by metric. Given the difference in marginal price between fossil fuels and renewables, reduction in fossil fuel dispatch (within operational limits such as reserve and minimum inertia levels) is proportional to the additional flexibility. The per-unit value is highest in the Low flexibility scenario, implying diminishing returns with more system flexibility. For renewable curtailment, the case is less clear. Avoided curtailment in a 24-hour period could be limited by the modelled weather year, but it is unlikely to change much year-on-year. Emissions are less affected by varied shifting potential as the peak versus off-peak emission intensity becomes more similar in 2035 with a lesser role for high-emission peaking plants. Peak shifting is usually away from less efficient gas plants, rather than the higher emission coal or oil plants.

The effect of Low, Base and High flexibility resource potential on key operational metrics for the modelled power system of Ireland, 2035



Note: gCO_2/kWh = gramme of carbon dioxide per kilowatt hour. The high case assumes +20% and low case -50% demand flexibility potential relative to the Base case.

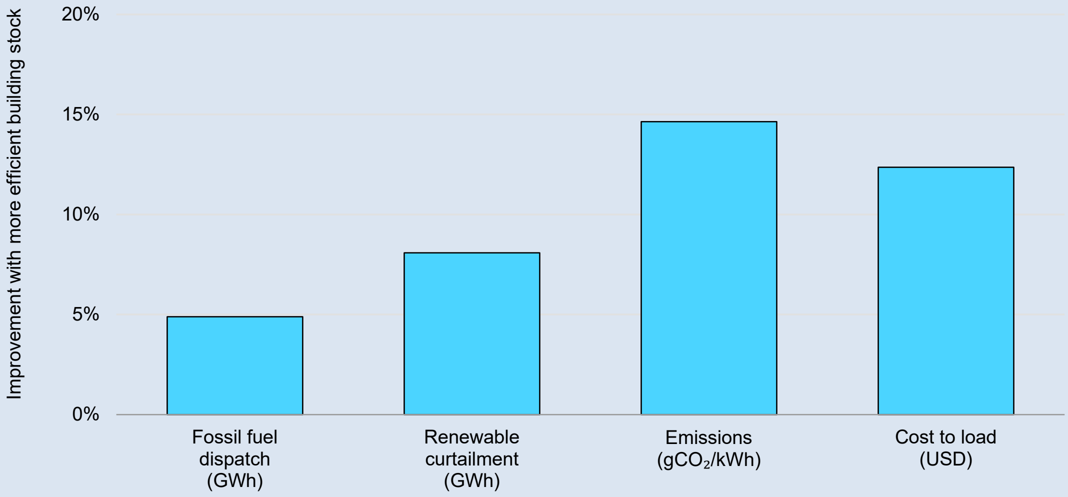
Building efficiency can increase the value of demand flexibility

Improving the efficiency of buildings has a key role in Ireland's decarbonisation plans. Its National Retrofit Plan, complete with a package of supportive policies, has established a target of upgrading 500 000 homes by 2030. These upgrades could have multiple benefits, creating warmer homes, improved health outcomes and higher property values. Better insulation and draught proofing can also contribute to better retention of building temperatures, enabling such buildings – as opposed to less efficient buildings – to more effectively match grid demand signals.

Building retrofits support longer duration heating demand shifting

The flexibility from more efficient buildings could also benefit Ireland's power system. IEA analysis shows how a higher efficiency building stock could avoid 15% more curtailment on the system, lower emissions by an additional 12%, decrease fossil fuel dispatch by a further 8% and reduce overall costs by another 5%. More ambitious building codes that include behind-the-meter storage, smart EV charging, building energy management systems or renewables could make building demand shifting even more valuable to the system and to consumers.

Additional benefits to the power system resulting from the demand flexibility of more efficient building stock in Ireland, 2035



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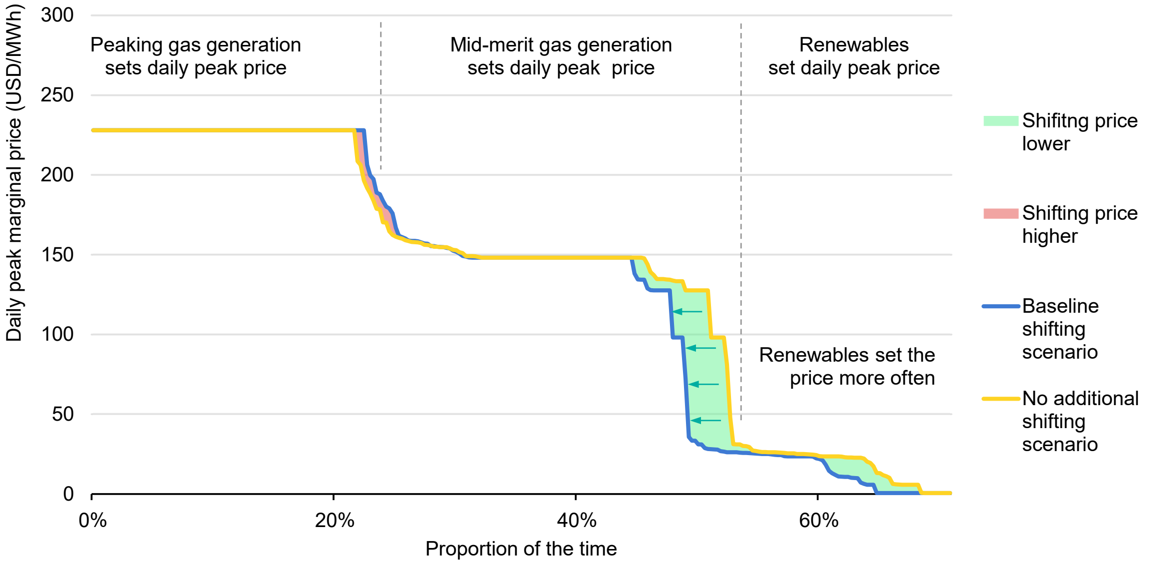
Notes: gCO_2/kWh = gramme of carbon dioxide per kilowatt hour; USD = United States dollar. Shifting durations for building-related demand sectors are reduced by 2 hours in the low-efficiency scenario and increased by 3 hours for the high-efficiency case. Analysis includes both residential and commercial buildings.

Demand flexibility could move price setting away from fossil fuels and towards renewables

Demand flexibility could allow otherwise curtailed wind generation to set the market price more often in Ireland. Because this lower cost renewable generation clears the market more often, flexibility lowers the wholesale price received by other generators during these periods, amplifying cost savings and shifting the price duration curve to the left. These benefits are partly offset by a modest increase in peaking generation associated with larger net load ramping events.

Effects of demand flexibility on the modelled price duration curve and merit order in Ireland, 2035



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Notes: The shaded areas of the graph highlights differences in total costs between cases. The x-axis is truncated at 70% since from 70% to 100% near zero marginal cost renewables set the daily peak price.

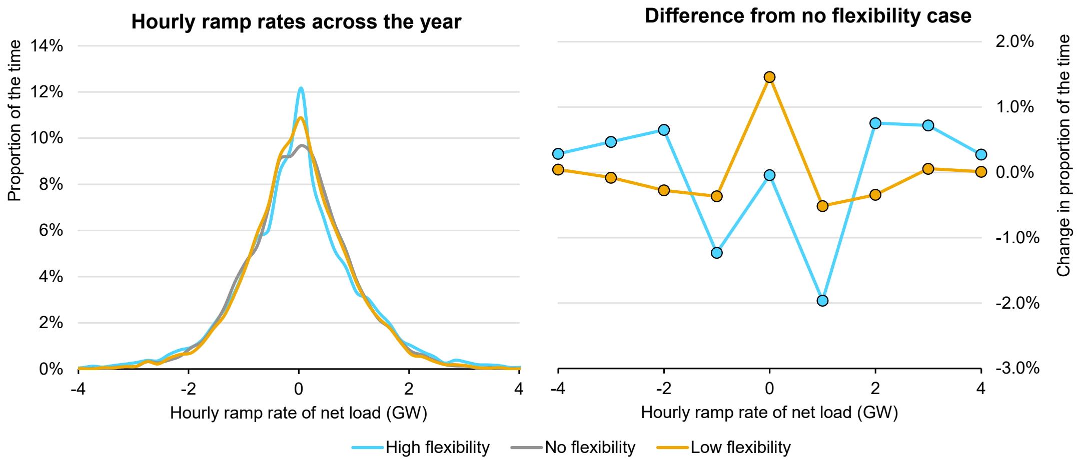
IEA analysis of Ireland in 2035 indicates that demand flexibility could reduce the total cost to load by 7-10%, depending on the share of demand flexibility. In 2025, this made up just over half of the 9.3 billion USD total electricity costs paid by all consumers (excluding supplier costs). At these costs, a 10% saving could lower the total cost of energy by nearly USD 500 million per year. Although it is uncertain how other costs, such as networks, balancing and capacity charges, could be distributed in 2035, energy costs will likely remain one of the main components.

Demand flexibility could reduce curtailment but may also increase operational complexity

For Ireland, depending on the capacity available on a given weather day, flexibility could lower or increase the ramping of supply-side flexibility needed to meet net load. In the Low flexibility case, the share of low ramp net load periods (less than ±0.5 GW) is increased by 1.5%, while higher ramp periods are reduced by this same amount, reducing the need for other system flexibility to ramp up or down.

The High flexibility case is, however, more complex. The share of periods with ramping of less than ±1.5 GW are reduced by 3.2%, resulting in the same increase in the number of periods with more dramatic ramps. While flexibility could reduce renewable curtailment, it could also create balancing complexity. If widespread, fully automated shifting behaviour is developed as expected for Ireland in 2035, this could distort the market signals driving the activation of flexibility.

Proportion of time at different hourly ramp rates (left) and difference in ramp rates (right) for modelled cases of High and Low demand flexibility in Ireland, 2035



Note: Ramp rate proportions are grouped in 1 GW bins in the right-hand graph.

Demand flexibility supports efficient electrification, reducing pressure on grid expansion needs

The Irish transmission and distribution operators anticipate spending a total of USD 15.2 billion to 2030. These investment cases are designed to be cost effective by balancing upfront costs (including in non-wire solutions such as efficiency and flexibility) with expected demand to avoid excessive investment in underused assets. Getting the right balance will be crucial to avoid grid capacity being a bottleneck for electrification plans.

IEA analysis of existing grid capacity shows how flexible heat pump operation, where technically feasible and accepted by consumers, could maximise use of the existing network. This could unlock existing network capacity for 50 000 heat pumps on medium voltage feeders and 170 000 on high voltage feeders[3] – nearly

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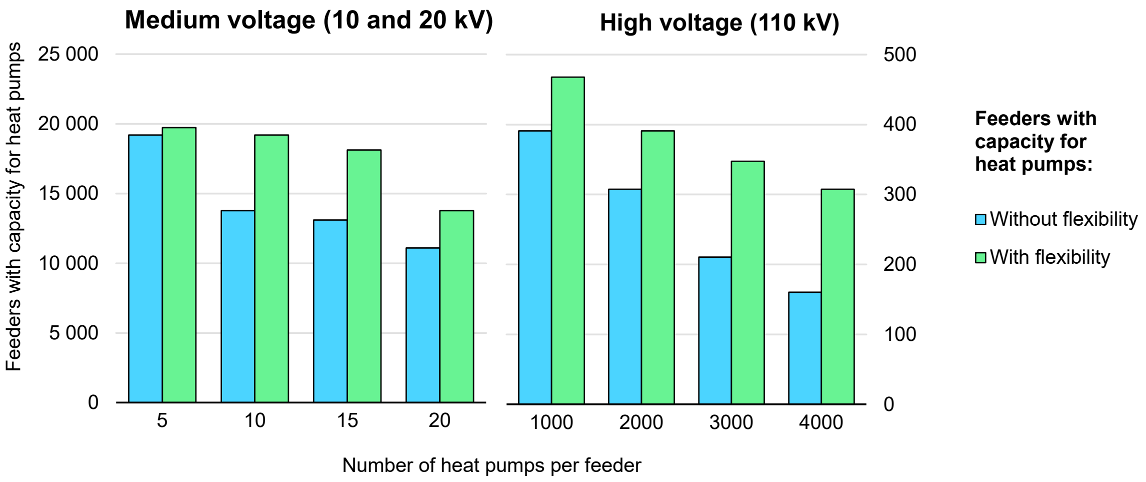
[3] Assuming an average of 10 heat pumps and 2 000 heat pumps per MV and HV feeder, respectively.

half the retrofit target of 400 000 residential heat pumps – and minimise costly capacity upgrades. In combination with building efficiency, retrofitting could reduce any disruption to energy services. Subject to customer acceptance, more grid capacity could also be freed up through flexible contracts, real-time management of feeder capacity and other smart grid solutions.

Number of medium and high voltage network feeders with spare capacity for heat pumps by flexible and unflexible heat pump operation, 2025



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Notes: Analysis assumes that peak heat pump demand (5 kW) could be reduced by 50% per field trials of demand shifting. The 2030 target would require an average of nine heat pumps for each of the 45 000 medium voltage feeders and 2 000 heat pumps for the 200 high voltage feeders in Ireland, but this will vary significantly with the location.

Sources: IEA analysis based on Electricity Supply Board (ESB) Networks (2025), Availability capacity heatmap; Turner et. al. (2025), Embedding energy flexibility capability in air source heat pumps via third-party control: Insights from a field trial on residential buildings in England; Nesta (2024); and Müller and Jansen (2018), Large-Scale Demonstration of Precise Demand Response Provided by Residential Heating Systems.

Flexibility can deliver consumer and system savings

Investment in supply-side flexibility, peaking generation and the grid was made by the distribution operator in 2025, constituting up 84% of the total cost of electricity. Demand flexibility could offset this investment, providing cost savings for the entire power system. For specific consumers participating in flexibility programmes, cost savings can be approximated from examples in other countries. These cost savings could be exaggerated for Ireland with greater uptake of renewables and variation in electricity prices, combined with dynamic tariffs.

- Through six demand flexibility programmes over a decade, a US university earned USD 4.1 million in revenue and made USD 10.5 million in cost savings.
- An analysis of 1 300 UK households with heat pumps that moved to time-varying tariffs found that customers saved 18% on their electricity bills.
- Households in Spain provided with free electricity during periods of high renewable output increased their demand by 12%.

Chapter 6. Implementation challenges for scaling up demand flexibility

Demand flexibility is already delivering measurable benefits to power systems today. However, the delivery models through which this value is currently realised were largely designed for short-duration reliability events, not for routine optimisation. With increasing electrification and digitalisation, flexibility could evolve from fragmented emergency response into a dependable, scalable and socially accepted system resource. In recognising the limitations of current approaches, it is important to focus on specific policies to show how market design, investment decisions and future policy could improve system outcomes.

Participation, equity and consumer inclusion

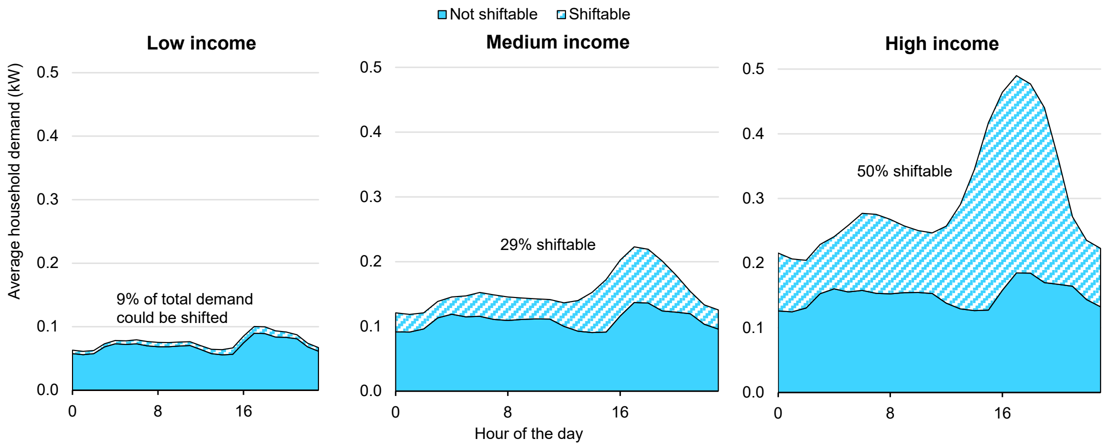
Demand flexibility relies on varying degrees of consumer participation. For example, emergency peak shaving mechanisms can include text message requests to lower demand during heatwaves. Urging that consumers manage demand could be considered an unfair burden if the system is too dependent on their response. Moving forward, automation like smart EV charging could lower the need for the direct intervention of consumers without interrupting energy services. Although this could reduce the burden on consumers, it still raises equity issues around autonomy, transparency, and who stands to benefit, which can form part of wider discussions about policy priorities. Understanding these issues and how policy can address them will be crucial to successfully scaling up flexibility.

Not all households or businesses can participate and benefit equally from flexibility

In the first instance, the potential buy-in from consumers can be limited by a lack of engagement in how electricity is provided. The preferences of these consumers should be respected in deciding the role demand flexibility is expected to play in power systems. Perceptions or trust of connected devices in households could also hinder flexibility potential, such as in Germany, where around half of consumer surveyed expressed no interest at all in smart home technologies.

Like other distributed energy technologies, a large share of benefits would go to participating households. In South Africa, up to 50% of demand from higher income households could be flexibly managed, compared with 9% of lower income households – a difference of five times. Households with greater access end uses like electric vehicles, smart appliances or home energy management systems would be best placed to capture the benefits of dynamic pricing. Those with less flexible demand, lower digital access or limited ability to invest in enabling technologies may be left behind.

Electricity demand that could be technically shiftable by income group in South Africa, for the average of all households, 2025



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Notes: The analysis shows the technically shiftable load, which is split by end uses, with each having different shifting potentials. The analysis assumes that the willingness to shift demand is dependent on technology type only, not the income bracket. Income groups are defined as having monthly incomes that are low = less than USD 300; medium = USD 300-1 200; and high = >USD 1 200.

Source: IEA analysis based on University of Cape Town (2021), Residential electricity consumption in South Africa.

Targeted support could enable direct participation benefits to be shared more widely. This could include subsidies for smart controls and efficient appliances, benefit-sharing for non-participants, and public reporting of participation and benefit distribution. Addressing these issues is not however limited to flexibility policy and should form part of wider discussions on country policy priorities.

Some businesses may have potentially flexible demand, but it can remain undetected. Not all companies – especially small and medium enterprises – are equipped to identify flexibility and its value. To address such gaps in understanding, the Flex-e programme in the Netherlands includes an energy audit that helps identify how the demand of a company could be flexible. The Smart Readiness Indicator provides an EU framework to assess the compatibility of buildings with smart technologies, including those that support demand shifting.

Programmes need to be designed with consumers in mind to avoid penalising inflexible users

Consumers with limited flexibility may not simply miss out on benefits, but they could potentially face higher costs. Research from Norway and the United States has found that lower income households with less flexibility and a greater share of demand at peak periods were more likely to experience dynamic grid tariffs as a financial penalty rather than as an opportunity. By contrast, higher income households were better able to respond to price variations and benefit financially. To help address this imbalance, countries such as South Africa have long offered progressive tariffs, where the first block of electricity is the cheapest. Countries like Spain have developed dynamic social tariffs, which aim to combine targeted consumer protection with time-responsive pricing.

Consumer response can also vary significantly across demographic groups. Research in Sweden found that women were twice as likely to report greater ability to shift electricity demand, while high income households were two-and-a-half times more likely than low income ones to report similar flexibility potentials. These behavioural and social differences introduce additional uncertainty into forecasting programme performance, and highlight the importance of designing tariffs and participation models that reflect real consumer behaviour.

Building the social licence is crucial at all stages

Building on consumer trust developed in early-stage programmes will be crucial. Research from Ireland reveals a wide range of consumer motivations for participating and engaging in demand shifting, which could be reflected in programme design. However, nascent support should not be taken for granted, particularly if moving towards fully automated shifting. In a US study, manual thermostat adjustments to override heating demand shifting can happen upwards of 30% of the time, materially reducing delivered system value. As consumer control becomes less visible, transparency around activation, financial rewards and service impacts will become increasingly important to maintaining participation and reliability. Device interoperability could help build consumer trust by enabling households and businesses to more easily switch suppliers, devices or service providers.

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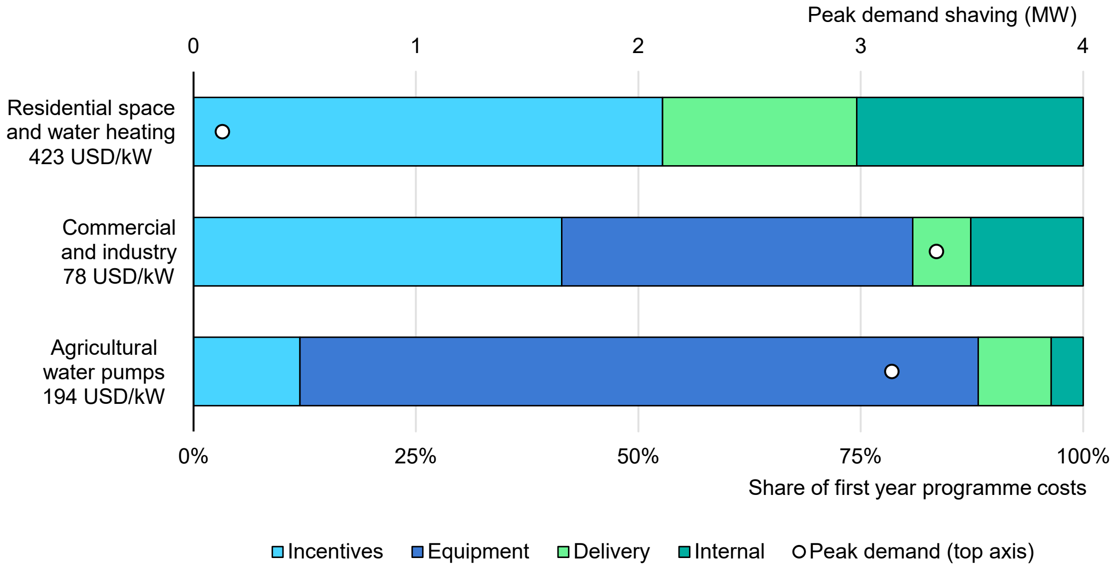
control becomes less visible, transparency around activation, financial rewards and service impacts will become increasingly important to maintaining participation and reliability. Device interoperability could help build consumer trust by enabling households and businesses to more easily switch suppliers, devices or service providers.

Programme specific costs

While demand flexibility could help offset power system costs, cost estimation can be complex. For a US utility, costs ranged from USD 78/kW for non-residential programme up to USD 423/kW for a residential water heating programme. The share of hardware costs ranged from zero, by leveraging existing smart thermostat suppliers, up to 75% for programmes requiring installation of control devices. Avoiding device lock-in and costly hardware replacements can be enabled through interoperability, and also the standardisation of demand-response readiness to minimise the retrofitting of control and communication hardware. However, despite lacking costs for additional hardware, the more costly residential programme was later discontinued following technology issues, showing how much cost estimation could affect uptake. Programmes will need fair incentives, effective co-ordination, and a supportive regulatory environment to be cost-effective.

First year share of total costs, and costs per kW for different demand response programmes in Washington State (United States), 2024



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Note: USD/kW = United States dollar per kilowatt.
Source: Pacific Power (2024), Demand Response Portfolio 2024 Annual Report.

Even with the same types of technology, other costs can vary with project scope. Demand flexibility delivered through programme-based approaches, rather than market-based mechanisms, can have higher overheads to develop and manage the same amount of flexible capacity. A review of US flexibility programmes found that mature smart thermostat programmes had an average cost of around USD 40/kW, but a smaller pilot project cost USD 875/kW. Although pilot projects can be more expensive to operate, they play a key role in developing an understanding of behaviour, and how it can be incorporated into demand response costing.

Valuing avoided costs for non-wire alternatives, such as flexibility and efficiency, is essential in comparison with other investments. To compare demand flexibility with supply-side resources in network planning, it is crucial to include aspects like avoided network and generation costs. Metrics like the total system cost capture the full range of these aspects and enable the clearest comparison of resources across the whole power system. Including the full range of these benefits can in some cases make the levelised cost of capacity negative, underlining the benefits that demand flexibility could provide to the system.

Limits and risks of emergency peak shaving models

Emergency peak shaving programmes are proven to provide rapid and cost-effective relief during periods of system stress. Countries such as the Netherlands have used flexible connection contracts as a short-term measure to accelerate grid access, while the Philippines and Singapore have programmes to compensate industrial consumers for reducing peak demand. Over-reliance on these approaches could however defer much needed infrastructure investment. Fragmented, programme-based and largely manual approaches can be effective for managing short-duration stress, but they are not suited to more frequent, system-wide use which would require more comprehensive flexibility frameworks in the years ahead.

Emergency peak shaving cannot replace structural investment

Emergency peak shaving mechanisms should not replace timely investment in energy infrastructure. While peak shaving programmes can manage infrequent peak events, they do not support continuous system optimisation or broad consumer participation. Over-reliance on short-term flexibility could delay essential upgrades, transfer operational risk from infrastructure to consumers and risk locking systems into emergency-only flexibility models. If demand response is valued only during crises, incentives to improve automation, expand participation or integrate flexibility into routine system operation generally remain weak.

Reliability can be more difficult to guarantee than with supply-side flexibility

A further challenge can be determining the reliability and verifying the extent of flexible demand. Unlike conventional generation, demand flexibility depends on a combination of consumer behaviour, device performance and demand that can vary by season, location, consumer type and event duration. Participation in emergency peak shaving programmes can also be concentrated among a small number of large industrial or commercial users. This could increase exposure to plant shutdowns, contractual changes or shifts in industrial activity, which can limit the diversity and resilience of the resource base and create uncertainty for system operators seeking to assign a firm capacity value to flexibility.

Without conservative measurements, verification and sufficient operational history, available flexibility can be overstated in planning and market design. Improving accuracy would require data on baseline demand, ex-post verification, resource availability, event duration, rebound effects, seasonal dependence, consumer override, communications failure and de-rating factors.

Digital metering will be essential for participation

Digital metering is also a prerequisite for participation in flexibility programmes by enabling demand to be measured and verified. With some countries, such as Japan, having now achieved near-universal smart meter penetration, several are preparing the next generation of advanced metering infrastructure. In other regions, limited digital infrastructure remains an obstacle to unlocking flexibility. Indonesia, for example, recently accelerated the rollout of advanced metering to 1.2 million customers in collaboration with the State Grid Corporation of China. However, trials of more accessible, plug-and-play metering and control devices in New Zealand demonstrate how simpler and more cost-effective solutions can empower consumers to manage their electricity demand.

Existing tariffs may unlock only limited flexibility and should evolve alongside flexibility capacity

Time-varying tariffs, if not already implemented, can provide a small but notable share of implicit flexibility to the system. Many EU countries use such tariffs to comply with cost-reflective pricing requirements, and South Africa has applied them to industrial consumers since the early 1990s. They can also be combined with tools enabling consumers to better understand their electricity use. Compared with more automated demand response though, the overall flexibility potential from ToU tariffs is nevertheless low, with opt-in uptake as low as 1%.

More dynamic hourly tariffs could also be considered, but other barriers must be addressed to realise their full value. For many companies, particularly those with a lower share of energy in their total costs, dynamic tariffs alone are often insufficient to encourage flexibility, necessitating new compensation mechanisms.

Demand flexibility could also affect utility cost recovery, similarly to other distributed resources. Research in California found that where tariffs recover fixed system costs through higher charges during peak periods, flexible consumers who avoid these periods could contribute less than expected towards cost recovery. Periodic reassessments of peak demand periods, as well as a full understanding of the existing flexibility on the system – including who is providing this flexibility – is needed to balance cost recovery between consumer groups and tariff types. This can ensure that non-flexible consumers are not penalised, while still incentivising flexibility activation.

The contributions of flexibility and efficiency may remain under-recognised in system planning

In the near term, demand flexibility can support resource adequacy and reliability assessments. While it cannot replace generation, it can reduce the probability of short-duration supply gaps. If demand measures are excluded from adequacy assessments, planning decisions may overstate the short-term system risk or undervalue existing, potentially low-cost resources. If not already included, incorporating conservative assumptions on flexible demand and efficiency could provide a more realistic picture of system resilience. The role of flexibility can then be developed through national roadmaps, as in the case of the United Kingdom and Singapore. Ireland’s ongoing National Energy Demand Strategy has set actions based on goals for 2024-2026, including demand flexibility, with updates expected by 2027 to inform the next targets.

Flexibility can also complement efficiency policies, contributing to better utilisation of existing generation and network assets while reducing peak-driven costs. The Canadian government, for example, recently announced USD 4.3 million of funding for Hydro Ottawa to develop enhanced AI analytics to forecast peak demand from consumer-owned assets, such as electric vehicles.

Developing smart automation to avoid flexibility fatigue

Where programmes rely on manual activation, consumers can experience response fatigue and withdraw from participating, reducing resource reliability. In South Africa, hot water control programmes have delivered good results, but also underline the common challenges of today's flexibility models.

The flexibility potential of water heating

Water heating offers significant flexibility potential due to the thermal inertia of water and widespread electrification – households were 60% more likely to have electric hot water than to have space heating across IEA countries in 2023. In South Africa, there are around 5 million electric hot water heaters which account for around 40% of an average household's electricity bill.

Combining efficiency and flexibility, minimum energy performance standards should deliver 3.8 TWh of savings by 2030, with a programme using analogue switches enabling up to 200 MW of peak demand reduction. However, control technologies have varied by municipality, with changes in signal providers and a lack of interoperability leading to the replacement of installed devices. Households have also been unable to override controls, contributing to lack of satisfaction.

Towards more advanced controls

South Africa has developed a pilot programme combining insulation with more advanced control solutions. Modelling indicates that this could deliver greater benefits for both households and the power system, improving energy availability during peak stress periods and minimising strain on participating households. The pilot programme illustrates how hot water flexibility could evolve towards more automated, interoperable and consumer-friendly delivery models.

Limits and risks of pilot-stage demand shifting

As emphasised throughout this report, demand flexibility could go beyond one-off peak shaving events. With growing electricity demand and shares of renewables globally, flexibility will not only be needed more often, but it will need greater precision across a range of consumers. The next step in the process is often building up to smaller-scale, managed demand shifting programmes. Thailand has demonstrated how countries can begin to understand flexibility performance across different end uses and in specific places, with a 2023 pilot project managed by the two main network operators achieving a maximum load reduction of

57.3 MW in the evening period. These programmes highlight the future potential for flexibility, while also revealing new risks and limitations.

Smaller programmes have greater overheads for cost and co-operation between stakeholders

Managing early-stage shifting programmes can be more complex than emergency peak shaving. To reliably deliver flexibility at growing scales, system operators, regulators, utilities and aggregators will need to develop institutional experience and operational data on forecasting demand, verification, digital operations, and consumer engagement. While peak shaving can be contracted between a single large energy user and the system operator, shifting programmes also require interactions with network operators, aggregation providers, end users and other stakeholders. In Ireland, co-ordination of transmission system operators and distribution system operators is supported by the Joint System Operator Programme.

When designing new programmes, starting small and iteratively improving can be beneficial, such as for India piloting the demand shifting of ACs. Provided interoperability is accounted for, it allows cost-effective programmes to grow after demonstrating proof of concept, while incorporating ongoing operational learning to maximise effectiveness and consumer buy-in. Starting smaller can also reduce the burden of co-ordination across different stakeholders, giving different organisations the time to gradually develop specific expertise and processes.

Digital readiness and interoperability will determine long-term success

Technology compatibility becomes more important at the pilot stage. A demand aggregation platform in Ireland analyses over 70 data sources, demonstrating the range of devices and sensors needed to share data seamlessly. As flexibility expands across larger numbers of devices, avoiding proprietary lock-in will help support consumer choice, supplier switching and cost-effective scaling. Protocols such as the Building Automation and Control Network and Open Automated Demand Response (OpenADR) have already been used in Thailand for networked devices.

End-use technologies might not yet be digitally enabled by default, which could require additional control and communications hardware that can be expensive to replace or upgrade. Standards requiring demand response ready capabilities for ACs in South Australia, or the smart charging functionality in new EV chargers in the United Kingdom, illustrate how product standards can reduce such barriers. Getting interoperability right the first time will have long-term benefits.

Regulatory sandboxes could help bridge the gap of reforming existing markets and regulations

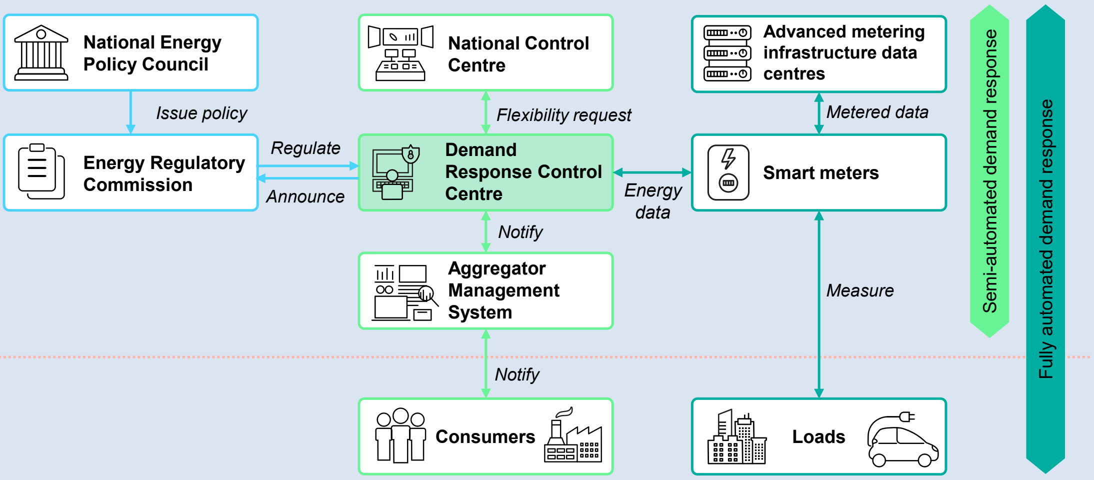
Traditional electricity markets might also be poorly configured for the integration of new resources. Market rules, tariffs and settlement details might discourage shifting or fail to allocate system cost savings to participants. Well-designed pilot projects can not only to demonstrate technical performance, but also to identify the market and regulatory barriers to wider adoption. In many cases, regulations are either not designed for demand flexibility or do not exist. Thailand has been operating its Energy Regulatory Commission Sandbox since 2019 to address issues that include grid interconnection, bidirectional electricity flow and interoperability for electric vehicles. France also recently opened annual sandbox applications to test flexible technologies.

The Demand Response Control Centre: Home of Thai demand flexibility

In 2023, Thailand launched two centres dedicated to helping manage the growing demand and supply side challenges of grid modernisation (e.g. integration of renewables), while leaving room to scale up in the future. The Demand Response Control Centre co-ordinates the actions of load aggregators, which pay consumers to adjust their demand in response to requirements from the system operator.

Load has been aggregated in the initial trial stage by the Metropolitan Electricity Authority and Provincial Electricity Authority. However, it is hoped that in future private agencies could become load aggregators, opening a new market for energy businesses under the co-ordination of the Demand Response Control Centre.

Operational process of the Demand Response Control Centre in Thailand



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Source: Adapted from Pinyo and Bangviwat (2023), Smart Contracts-Based Demand Response Bidding Mechanism to Enhance the Load Aggregator Model in Thailand (accessed 20 May 2026).

Limits and risks of fully integrated and automated flexibility

Pilot projects can assist in building understanding on how technologies perform and what response they provide. However, successful pilot projects do not automatically scale into system-wide resources and could remain fragmented. To evolve into a more integral system resource will require wider participation, stronger integration into long-term planning and more automated dispatch based on market signals. Automation particularly could capture greater value for consumers and the grid, but this will require consumer trust, digital infrastructure, operational experience and regulatory maturity.

Market participation could distort price signals if poorly co-ordinated with other resources

If flexibility becomes more widespread and automated, co-ordination across devices and programmes becomes increasingly important. The larger the market role, the more likely shifted demand could distort the market signals that dispatch it. If flexible resources respond at the same time to price signals or dispatch instructions, demand could be synchronised rather than diversified, creating new "shadow peaks" that shift congestion to different times or locations on the network. These rebound effects may not be visible at the level of the whole system, but could become significant on local feeders or network areas.

Avoiding such an outcome may require co-ordination between wholesale markets, distribution system operators and aggregators, as well as greater use of locational signals and real-time network visibility as flexibility scales. In its attempt to address these issues, Ireland's contribution to the under-development EU Network Code on Demand Response will define legally binding requirements for data exchange, grid service participation, locational signals and response times for all actors.

Reliability becomes critical for daily system operation

Flexibility becoming a core market mechanism and meeting system operator requirements would require clarity around resource availability, operational performance and long-term reliability. Existing uncertainty is reflected in Ireland's target of 20% to 30% flexible demand by 2030. Experience in early-stage pilot projects can help build the multiple years needed of reliability metrics, performance confidence and appropriate capacity values. As this evidence is collected, planning regulations can gradually evolve to reflect the growing role of demand-side resources. In Austria, for example, reform is underway in electricity markets to better recognise the system value that demand flexibility can provide.

A balance is also needed in relation to the inherent uncertainty in relying on consumer behaviour. Countries like Germany have implemented requirements for flexible resources above 4.2 kW, which are to be directly controlled by the network operator. Over-reliance on demand flexibility could create tensions between participants – who want uninterrupted energy services – and system operators, who want to avoid costly service disruptions. Addressing these tensions without jeopardising the needs of either group will be crucial to long-term integration.

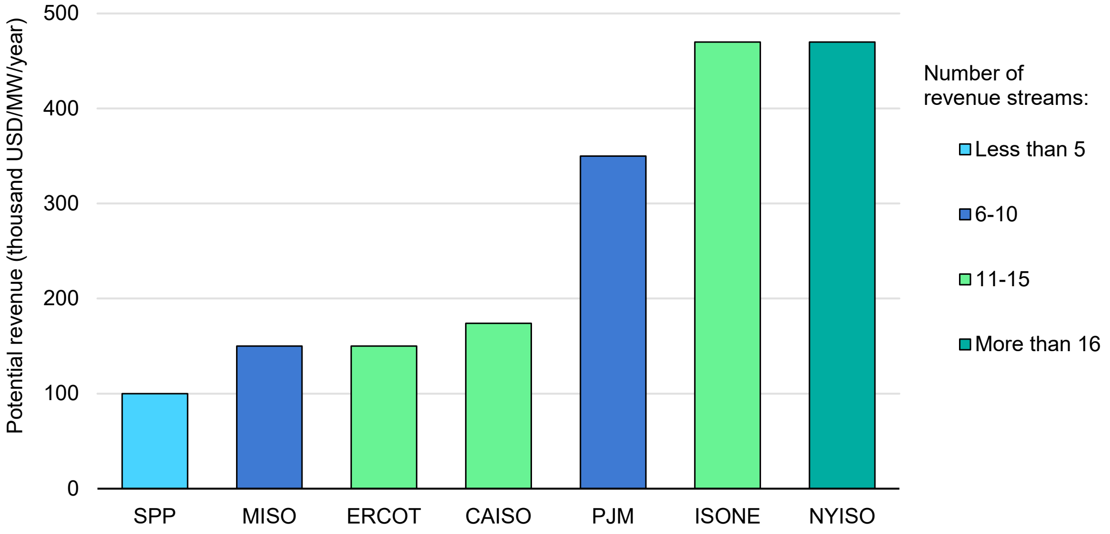
System dependency heightens the need for a robust approach to digital resilience and cybersecurity

Cyberattacks on energy systems increased more than threefold between 2020 and 2024. Although distributed resources can be more physically secure than centralised ones, if flexibility becomes more deeply integrated into daily market operations, digital resilience will be equally as important. Aggregated demand response differs from large energy users in the potential number and variety of devices involved, increasing the potential surface for cyberattacks. High-speed data sharing between interconnected devices could increase exposure to both accidental and malicious disruption. Software failures, communication outages or poor data quality could all affect the reliability of flexible demand as a system resource. Cybersecurity must therefore play a central role in the widespread uptake of demand flexibility, which will include the security of individual networked devices, data exchange processes and any automation of demand shifting.

Value to the grid will need to be shared with consumers

To maximise value, flexibility could be made available across multiple grid services. Depending on the technology, this could include balancing services (e.g. frequency response), frequency restoration, voltage regulation, capacity markets, congestion management and balancing markets. It will also mean avoiding curtailment or peak demand. Automatic dispatch and income optimisation across markets, combined with competition among aggregator suppliers, could support optimal revenue for consumers. Technology neutral ancillary services and minimising other regulatory barriers to participation, in addition to streamlining data sharing, would be needed to achieve this. Ireland has already laid the groundwork by enabling future revenue stacking under its main Demand Flexibility Product. Where demand response programmes are more developed, for example in the United States, flexibility providers in some regions can take advantage of over 20 income streams to maximise income.

Potential revenue for participants, and number of available revenue streams from value stacking in major US network regions, 2026



Notes: CAISO = California Independent System Operator; ERCOT = Electric Reliability Council of Texas; ISONE = Independent System Operator New England; MISO = Midcontinent Independent System Operator; NYISO = New York Independent System Operator; PJM = Pennsylvania-New Jersey-Maryland (Interconnection); SPP = Southwest Power Pool; USD/MW/year = United States dollar per megawatt per year. Not all value streams can necessarily be activated simultaneously.

Source: Voltus (2026), Power market data.

Integration of flexibility into planning frameworks should build on early-stage experience

For flexibility to integrate with longer term planning frameworks, flexibility will need to demonstrate reliability and predictability. As evidence builds, planning regulations can gradually evolve to reflect the growing role of demand-side resources. At all stages, it is essential that lessons are gathered in different organisations and jurisdictions, and that these lessons are assessed and shared for the benefit of future programmes.

With greater operational experience, countries could include demand flexibility in system planning as an alternative to supply-side resources. European distribution operators are already required to consider alternatives to grid expansion, such as efficiency and flexibility, by comparing more traditional supply-side flexibility, the additional benefits of flexibility discussed here and specific implementation costs. However, longer term operational experience remains essential before flexible demand can be considered a fully dependable system resource in adequacy assessments, peak load estimations or investment planning.

Chapter 7. Policy priorities for scaling up demand flexibility

Realising the full value of demand flexibility will require that policy frameworks evolve alongside changes in power systems, consumer technologies and patterns of electricity use. This report demonstrates how demand flexibility might emerge under very different system conditions and through multiple pathways, from emergency demand responses to automated, market-integrated services. Translating growing experience into scalable and durable system value will require policy choices that provide strategic direction, reduce uncertainty and support co-ordinated action across institutions, markets and consumers.

Measure and value flexibility as a system resource

Establishing transparent methodologies for assessing regional flexibility potential could improve decision making and support more efficient planning. Such methodologies could distinguish between technical potential, flexibility accessible under current markets and operationally reliable flexibility. National flexibility roadmaps could help clarify institutional responsibilities for regulators, system operators, aggregators, end users and policy makers. Such roadmaps can also identify priority end uses and establish milestones as flexibility evolves from being a tool in emergency programmes to an integral part of routine operational use.

With evidence of performance, system planers could progressively incorporate demand flexibility into the following areas:

- Generation adequacy assessments.
- Transmission and distribution planning.
- Congestion management studies.
- Security-of-supply analyses.
- Long-term system cost optimisation.

Build the digital and technical foundations early

Advanced metering, building management systems, ensuring interoperable communications and securing data exchange can act as a foundation for wider participation across residential, commercial, transport and industrial sectors. These same foundations can also support the deployment of AI-enabled tools to improve forecasting, automate demand response and optimise the operation of flexible energy resources. Early adoption of common standards could reduce long-term integration costs, minimise vendor lock-in and support supplier competition as flexibility scales. As digitalisation expands creating a wider footprint that may expose new vulnerabilities in system security, cyber security must be a priority. Strengthening digital skills across the workforce is critical to ensuring that new technologies can be deployed, operated and maintained effectively at scale.

Developing the digital foundations for demand flexibility could include:

- Deployment of smart metering and access to data.
- Energy and flexibility audits.
- Building and industrial energy management systems combined with automation.
- Connectivity, communication and interoperability standards.
- Workforce digital skills and cybersecurity standards for digital energy assets.

Place consumers at the centre of flexibility design

The long-term availability of demand flexibility depends on households, businesses and industrial consumers signing up and participating in flexibility programmes. This can be is strongest when programmes are transparent, there is clear compensation and the impacts on energy services are limited. If activation becomes more frequent and automated, maintaining consumer confidence becomes even more important. If deemed part of wider policy priorities, targeted support would be essential to ensure consumers have equal access to flexible technologies and their potential benefits. However, it is likely that not every customer may be willing to, nor able to participate in flexibility services, highlighting the need for policies that consider potential distributional impacts and ensure benefits are shared equitably.

Programme design can support long-term and sustainable participation through:

- Clear communication of programme conditions and expected benefits.
- Transparent compensation arrangements.

- The ability of consumers to override flexibility events.
- Minimum service standards for comfort, mobility and business continuity.
- Targeted support for consumer as appropriate.

Ensure flexibility markets are inclusive, efficient and technology-neutral

Removing barriers to participation in grid services could broaden the resources available to system operators and improve competition between supply- and demand-side solutions. As flexibility matures, enabling participation across multiple power market segments could strengthen the business case while improving overall system efficiency.

Regulatory and market reform can support:

- The participation of aggregators and third-party service providers.
- Proportionate metering and verification requirements.
- The lowering of participation thresholds for smaller distributed resources.
- Access to balancing, capacity and congestion management services.
- Tariff structures that better reflect temporal and locational needs of the system.

Integrate demand flexibility alongside wider system transformation

Power systems with greater diversity of technologies will be more secure and affordable, so optimal technology choices will likely include other demand-side and supply-side technologies, including energy efficiency, network reinforcement and distributed generation. As power systems become increasingly electrified, digitalised and decentralised, demand flexibility could support the more efficient use of both existing and future infrastructure.

Planning frameworks can therefore support:

- Evaluations of flexibility as a non-wire alternative, where appropriate.
- The development of a better understanding of cost drivers and examples, in accordance with the technology.
- Joint assessments of efficiency and flexibility potential.
- Co-ordination between transmission and distribution system operators.
- Use of locational signals to manage network constraints.

Move towards a more flexible and efficient power system

The experiences of Ireland, South Africa and Thailand, as well as that of other countries demonstrated in collected case studies, show that demand flexibility is no longer a niche intervention limited to periods of system stress. As electricity systems evolve around the world, flexibility could increasingly become part of how grids are planned, operated and optimised.

For countries that can demonstrate the cost-effective flexibility potential, the next phase will be scaling up the implementation of demand flexibility. Through the Digital Demand-Driven Electricity Networks (3DEN) initiative, the IEA is providing policy advice and insights to countries in developing the digital, regulatory and market foundations needed to support more dynamic electricity systems. An important part of this initiative is ensuring improvements in the visibility of demand, enabling interoperability between connected devices and networks and creating frameworks that allow flexible demand to participate alongside conventional system resources.

The pace of electrification at the global level has meant that these changes are becoming increasingly important for system operation and investment decisions. Countries that successfully integrate flexibility into electricity planning and market design will be better positioned to manage rising demand, contain system costs and improve the efficiency of increasingly complex power systems.

Annex. Description of modelling

This report features demand flexibility case studies for (in chronological order) – South Africa (2025), Thailand (2030) and Ireland (2035). With historic data on power system performance and flexibility operation available for South Africa (2025), this was used to demonstrate the effects of flexibility on the system. For Thailand (2030) and Ireland (2035), a forward-looking power systems model was needed to quantify the system effects.

Demand flexibility modelling

Demand flexibility potential has been modelled for all three countries that are the focus of the case studies presented in this report using the methodology of the Global Energy and Climate Model. Demand profiles split by end-use for each country were combined with country-specific projections of smart technology uptake developed by Guidehouse. Scenarios of demand flexibility potential were developed to reflect the ranges of electrification and controllability of energy demand across commercial, industrial, residential and transport demand sectors.

Demand flexibility potential is modelled based on detailed end-use modelling. This demand is then combined with end-use specific factors, which describe how much of the demand could be shifted or shed. The share is the product of three flexibility factors: shiftability, controllability and acceptability, which can be defined as follows:

- **Shiftability**: Share of the load of each end use that can be shed, shifted or increased through a typical demand response strategy.
- **Controllability**: Share of the load of each end use associated with equipment that has the necessary communications and controls in place to trigger and achieve load sheds or shifts.
- **Acceptability**: Share of the load for a given end use associated with equipment or services where the user is willing to accept a reduced level of service during a demand-response event in exchange for financial incentives.

This framework enables scenarios to consider demand flexibility from various technologies and at varying levels of social acceptability. Scenarios of demand flexibility potential were also used in the power system models for Thailand and Ireland, which are described in the following sections.

Description of the Thailand PLEXOS model

The modelling work for Thailand uses an updated version of the 2023 model that was used in the report entitled Thailand's Clean Electricity Transition (see the Annex of the hyperlinked report for a description of the older model). This section will detail how the model was updated in terms of data sources and demand flexibility modelling.

The IEA updated its power system model of Thailand for the 2025 calendar year. The model is built in the PLEXOS© Integrated Energy Model.[4] For this study, its operation was restricted to the economic dispatch functionality. The model employs a temporal resolution of an hour, using forecasted hourly demand profiles that were previously provided by Thailand's Energy Policy and Planning Office (EPPO) and extrapolated to 2025. Generation capacity, network capacity and fuel prices were also updated to 2025, while the techno-economic characteristics of power plants (including imports), hydropower energy constraints, variable renewable energy (VRE) production profiles, fuel supply constraints, operating reserves, and transmission lines are represented as in previous versions of the model.

Regional representation and transmission

The model represents Thailand and is based on five main control regions within the Electricity Generating Authority of Thailand (EGAT), namely: Central (CAC), Metropolitan Bangkok (MAC), Northern (NAC), North-Eastern (NEC) and Southern (SAC).

The transmission system is based on the existing network. Transmission is only modelled as transfer capacities between the different regions, as provided by the Electricity Generating Authority of Thailand (EGAT) and updated to 2025. Losses were not explicitly modelled but instead were part of the input demand. Interconnectors with neighbouring Lao, People's Democratic Republic (PDR), and Malaysia were not explicitly included in the model. Instead, generation from Lao PDR under bilateral power purchase agreements were modelled explicitly as part of either Thailand's Northern or North-Eastern regions (depending on the interconnected region). Conversely, the 300 MW high-voltage direct-current interconnector with Malaysia to the Southern region of Thailand was explicitly excluded given its restricted use for high-price periods.

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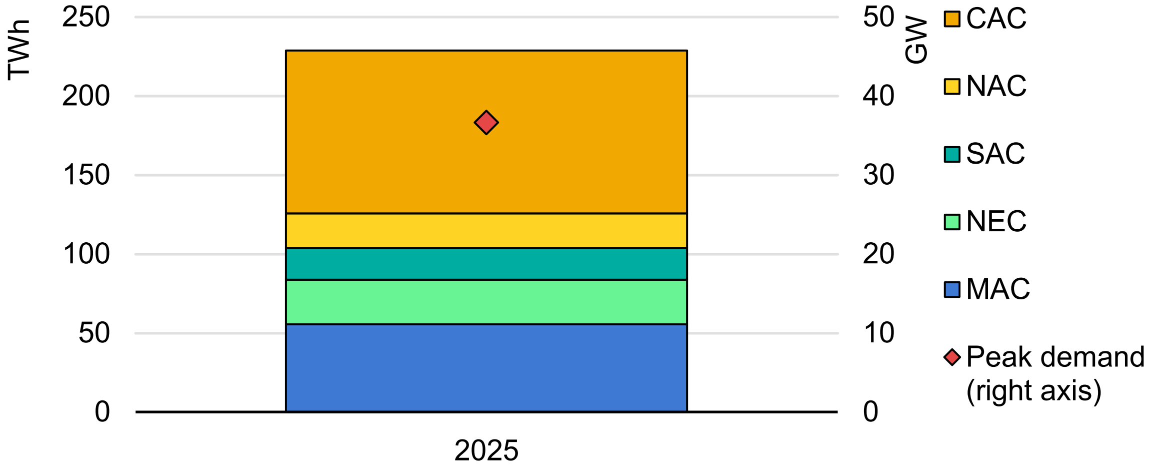
[4] PLEXOS© is an energy market simulation package for modelling the power system over different time frames, ranging from long-term generation capacity expansion to short-term dispatch and unit commitment.

Modelling demand and reserves

For Thailand, demand is represented at a regional level based on data from EGAT and is extrapolated to 2025 using data from EPPO. These values are then processed into hourly load profiles as described in the [Global Energy and Climate Model](#).

Operating reserves are also explicitly modelled, allowing for co-optimisation with the unit commitment economic dispatch solution. The spinning reserve requirement is based on EGAT's system-wide requirement of a 1 500 MW load risk during peak periods and a 700 MW load risk during off-peak periods.

Annual electricity demand in Thailand by region (left axis) and peak demand (right axis), 2025



IEA. CC BY 4.0.

Note: CAC = Central (region of Thailand; MAC = Metropolitan Bangkok; NAC = Northern; NEC = North-Eastern; SAC = Southern.

Representation of the generation mix

The generation mix in Thailand was updated for 2025, using publicly available sources, by adding new capacity and removing retired capacity. This generation consist of various technologies defined according to several techno-economic characteristics and operating constraints, which are based on information provided by EGAT. In the absence of such information, they are defined in accordance with industry best practice. Broadly speaking, and in the context of Thailand, these power plants can be divided into conventional thermal, hydro and VRE plants. In addition, there are several small power plants of various technologies, aggregated at a regional level, which run according to specific patterns as indicated by EGAT. In general, the following parameters of these plants are modelled: minimum stable level, run-up rates, ramp rates, average heat rates, outage rates (both forced and maintenance) with mean time to repair, minimum up and down times, average start-up costs, and variable operation and maintenance costs. In addition, the fuels used by specific generators, or sets thereof, are also modelled, including fuel prices and fuel constraints. Liquefied natural gas and natural gas prices are modelled monthly, which represents a change from annual modelling in previous reports.

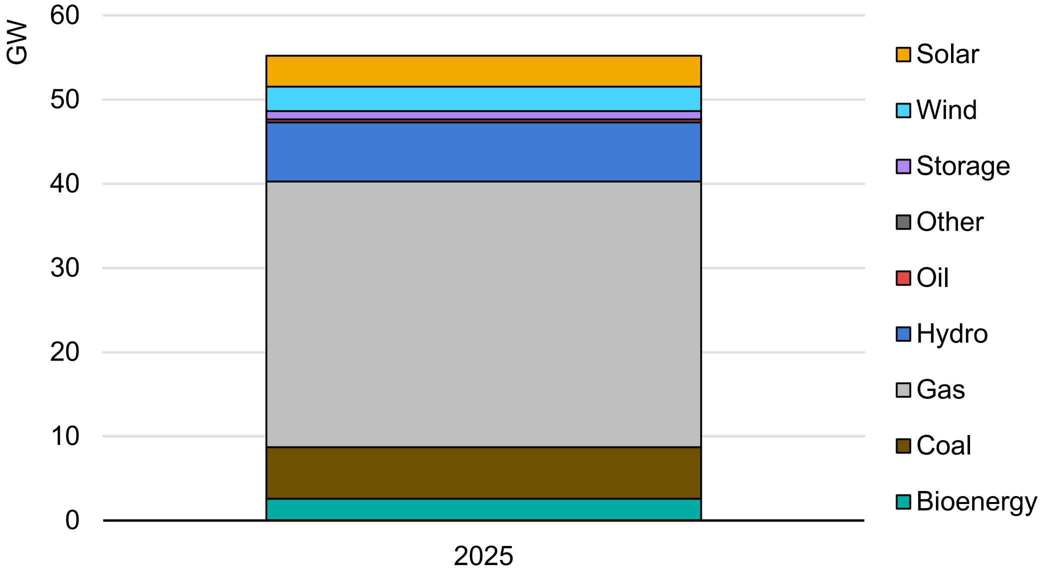
In the case of hydro plants, the generators are separated into one of three groups:

- Run-of-river plants with daily pondage schemes;
- Plants with large reservoirs;
- Off-stream (stand-alone) pumped storage hydro schemes.

The seasonality of inflows for hydro plants is captured with monthly resolution, which is based on average values from historical data provided by EGAT. In the case of run-of-river plants, the monthly availability of hydro energy is spread evenly across the days over which a pondage scheme can regulate on a daily basis. Large reservoirs, on the other hand, can optimally regulate output across the month. However, a certain portion (30%) of minimum hydro generation (daily for reservoirs, hourly for run-of-river plants with pondage) is also defined based on assumed environmental flow constraints for the river systems on which the hydro plants are located.

Wind and solar PV profiles are, for their part, based on historical resource profiles that have been aggregated. In all cases, spatial distribution of the generation is captured by assigning the appropriate generator to one of the five regional nodes.

Annual installed generation capacity by fuel type in Thailand, 2025



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Sensitivities

Various sensitivities were examined to explore the effects of different levels of demand shifting capability within the existing electricity system in Thailand. The main scenarios test different projections of smart device penetration in Thailand unlocking different amounts of flexibility, against a scenario of no dispatchable demand response. Demand shifted away from its original profile must be met within the shifting duration, while demand shed is not required to be recovered. Other scenarios explore variations in gas prices and electric vehicles (EVs).

Sensitivity assumptions applied to the 2025 base scenario for Thailand

Description	Differences versus no flexibility	Comment
Low/Base/High flexibility deployment	Base: 43.6 TWh potential, 4.3 TWh activated Low: 15% lower than Base. 37.1 TWh potential, 2.2 TWh activated High: 20% higher than Base. 52.3 TWh potential, 5.1 TWh activated	Estimates of low, baseline and high smart device deployment produce different flexibility potentials against a no-flexibility scenario.
Low/high gas prices	Low: USD 3.97/GJ average gas price High: USD 31.89 /GJ average gas price	Historic monthly gas prices in Thailand are taken from a low-price year (2020) and a high-price year (2022). These cases from recent years represent somewhat extreme differences but illustrate well the volatility in gas supply.
Low/high EV penetration and flexibility	Low: no EV flexibility High: eight times increase in EV penetration and increased flexibility	Compares a case with no EV flexibility to one with aspirational levels of EV penetration and high flexibility.

Notes: EV = electric vehicle; USD/GJ = United States dollar per gigajoule.

Description of the Ireland PLEXOS model

The modelling work for Ireland used in this report is the same as the model that was used for the 2025 report entitled Powering Ireland's Energy Future. This section will summarise the model in the same way that it is summarised in the Annex of the 2025 report, highlighting changes in data or the modelling methodology.

The hourly production cost model simulates hourly unit commitment and security-constrained economic dispatch to meet demand while respecting planned system constraints. This report used an adjusted version of the Adapted Transition

Pathway scenario for 2035, for which the assumptions are based on the Self-Sustaining scenario of EirGrid's Tomorrow's Energy Scenarios (TES) 2023.

More detailed demand shifting and shedding was added to the model to investigate the effects of advanced shifting capabilities. A range of demand shifting potentials was derived from projections of smart device penetration by sector, reflecting the range of scenarios of electrification and controllability of energy demand, primarily across commercial, industrial, residential and transport demand. A full list of the scenarios is presented subsequently in this section.

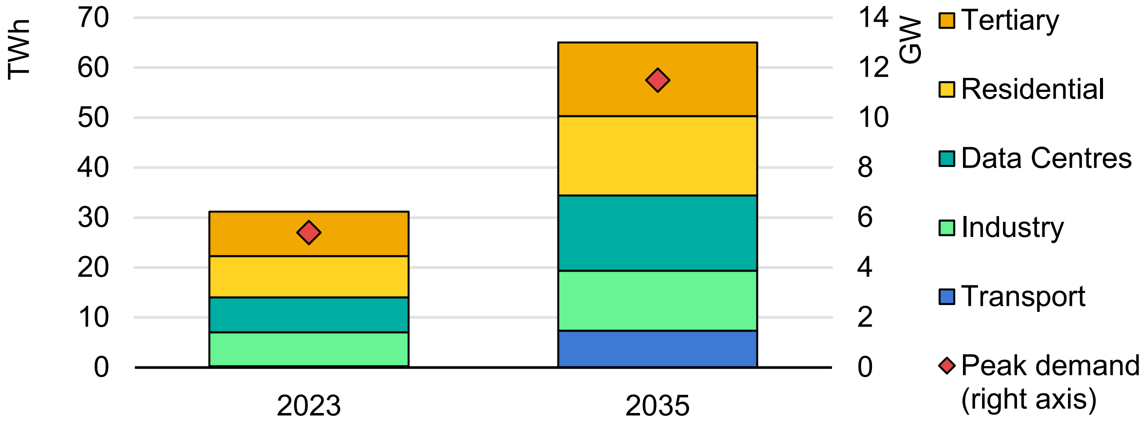
Regional representation and transmission

Ireland and Northern Ireland are modelled explicitly as regions connected by 1.2 GW of transmission capacity, anticipating the completion of the North South Interconnector. France and Great Britain are simplified and presented as sources of available imports to Ireland and Northern Ireland.

Demand

For Ireland, hourly load profiles are derived from sectoral demand totals after combining EirGrid and ESB data, processed into hourly load profiles as described in the methodology used for the Global Energy and Climate Model. Hourly electricity demand for Northern Ireland for 2035 is taken from EirGrid data from the Self-Sustaining scenario of TES 2023. Transport and residential electrification rates are higher in 2035, presenting a power system that is progressing towards the cross-sectoral electrification targets of Ireland.

Annual electricity demand in Ireland by sector (left axis) and peak demand (right axis), 2023 (historical) and 2035 (Adapted Transition Pathway)



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Note: "Tertiary" includes commercial and service demand. 2035 values are from the Adapted Transition Pathway.

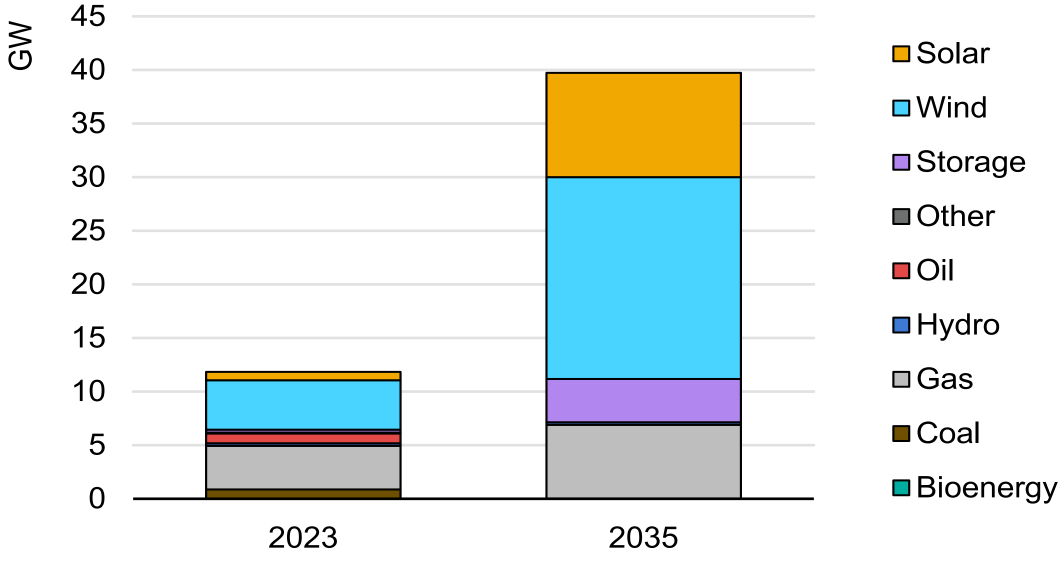
Generation

Installed generation capacity, technical characteristics (i.e. heat rates, ramp rates, minimum up/down times, minimum stable level, outage rates and mean time to repair) and cost parameters (i.e. fuel costs and variable operation and maintenance costs) are based on data from EirGrid and the public domain. When plant-specific information was unavailable, generic characteristics were assumed according to plant technology.

For Ireland and Northern Ireland, larger existing thermal plants were aggregated for 2035 to avoid introducing bias from speculative choices on plant closures. Aggregated plants were modelled with representative unit sizes for each region to maintain realistic unit commitment decisions, using generic technical parameters according to plant technology.

Capacity assumptions for 2035 are based on the EirGrid TES 2023 Self-Sustaining scenario. Although EirGrid TES scenarios incorporate hydrogen turbines and gas carbon capture, these technologies remain unproven at scale. Moreover, there is a lack of clear intention from market participants in Ireland to deploy these technologies in the coming decade, as well as uncertainty around the availability of low-carbon hydrogen. This hydrogen and gas carbon capture capacity was therefore categorised as low-carbon fuels, recognising that other technologies may be needed, and irrespective of the fact that the 5.7 TWh biomethane production target would be sufficient to provide all of this low-carbon dispatchable generation in the 2035 model results.

Annual installed generation capacity by fuel type in Ireland, 2023 (historical) and 2035 (Adapted Transition Pathway)



IEA. CC BY 4.0.

Operational constraints

Several operational limits were enforced in the model alongside technical generator parameters to replicate real-world operating conditions. These limits were based on EirGrid's and SONI's Operational Policy Roadmap 2025-2035, which were confirmed with EirGrid.

Minimum conventional units online

The 2024 minimum of four conventional units in Ireland and three in Northern Ireland was removed for 2035, meaning no minimum number of conventional units was enforced.

Inertia

The system operators plan to maintain the current all-island minimum inertia level of 23 gigawatt seconds (GWs). Trials are planned to introduce regional inertia constraints for Ireland and Northern Ireland, but the overall minimum is expected to be maintained. This constraint was implemented in the modelling to enforce 23 GWs of inertia in each hour. The recent procurement target of 10 GWs of low-carbon inertia services is assumed to be operational across Ireland and Northern Ireland, with a second, duplicate round of procurement assumed to deliver an additional 10 GWs of inertia for 2035.

Although it would be theoretically possible to cover the entire minimum inertia with low-carbon services, it has yet to be tested on a system-wide scale. A detailed technical evaluation and real-world trials would be required to verify that these low-carbon services could cover 100% of the system services of thermal generation.

Maximum system non-synchronous penetration

This restriction limits the proportion of supply in each hour from non-synchronous sources, such as solar and wind, as well as from interconnections and batteries. The current limit of 75% non-synchronous supply in the system is assumed to have been removed completely in 2035.

Reserves

Electricity system operators hold spare generation capacity at all times to adapt to the various uncertainties inherent in system planning, such as demand or generation forecast errors or unplanned network or generator outages. In addition to meeting hourly demand, the model was required to hold reserves to reflect this practice. Reserves were enforced for each region, with the reserves from Ireland

and Northern Ireland covering the expected reserve levels from EirGrid's 2025 All-Island Resource Adequacy Assessment.

Sensitivities

Numerous sensitivities were examined to explore the effects of different levels of demand shifting capability, as well as other opportunities and risks relevant to the Single Energy Market. The main scenarios test different projections of smart device penetration in Ireland, unlocking different amounts of flexibility, against a scenario of limited flexibility based on public data of dispatchable demand response units available in 2023.

Demand is binned into shifting durations consistent with the IEA Global Energy and Climate Model. Demand shifted away from its original profile must be recovered within the shifting duration, while demand shed is not required to be recovered.

Sensitivity assumptions applied to the 2035 Adapted Transition Pathway scenario

Description	Differences versus limited flexibility	Comment
Low/Base/High flexibility deployment	Limited flexibility: 200 MW Base: 10.1 TWh potential, 4.3 TWh activated Low: 50% lower than Base. 5.1 TWh potential, 2.2 TWh activated High: 20% higher than Base. 12.1 TWh potential, 5.1 TWh activated	Estimates of low, baseline and high smart device deployment produce different flexibility potentials against a limited-flexibility scenario with a limited amount of demand shedding, similar to historic levels.
Low/high building efficiency	Low: two hours' shorter shifting window duration High: three hours' longer shifting window duration	Building-related demand shifting is assigned to longer or shorter shifting windows to simulate different building efficiency levels.

Abbreviations and acronyms

3DEN	Digital Demand-Driven Electricity Networks (IEA initiative)
AC	air conditioning
BESS	battery energy storage system
CO_2	carbon dioxide
EGAT	Electricity Generating Authority of Thailand
EMDE	emerging markets and developing economies
ESB	Electricity Supply Board (Ireland)
EU	European Union
EV	electric vehicle
gCO_2/kWh	gramme of carbon dioxide per kilowatt hour
GDP	gross domestic product
GJ	gigajoule
GW	gigawatt
GWh	gigawatt hour
GWs	gigawatt seconds
HV	high voltage
IEA	International Energy Agency
kW	kilowatt
kWh	kilowatt hour
MV	medium voltage
MW	megawatt
OCGT	open-cycle gas turbine
OpenADR	Open Automated Demand Response
P2P	peer-to-peer
PV	photovoltaics
STEPS	Stated Policies Scenario (IEA)
TES	Tomorrow’s Energy Scenarios 2023 (EirGrid)
ToU	time-of-use (tariffs)
TWh	terawatt hour
USD	United States dollar
USD/GJ	United States dollar per gigajoule
USD/kWh	United States dollar per kilowatt hour
V1G	managed (smart) one-directional EV charging
V2B	vehicle-to-building
V2G	vehicle-to-grid (bidirectional smart charging)
VRE	variable renewable energy
VSD	variable speed drive

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