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Powering Britain: A comparison of policy pathways to 2050

Prepared for Onward

July 2026

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About this report

Transira Energy is an independent energy advisory practice that has been commissioned by Onward to assess the impact of a significant shift in UK energy policy between 2030 and 2050.

Transira has modelled two policy scenarios to quantify the impact on costs and emissions from the GB power sector:

Business as Usual ('BAU'): A scenario reflecting the likely evolution of the power system under the current policy framework, making progress towards a fully decarbonised economy, but falling short of achieving the UK's statutory 2050 net zero target and 2030 Clean Power target. The scenario assumes continued policy support for the expansion of wind and solar generation, alongside other flexible and low-carbon technologies, network expansion and the electrification of the economy. A clean power system is achieved by 2045.

Alternative Policy Pathway ('APP'): A scenario under an alternative policy framework developed by Onward, which assumes that the UK's statutory 2050 net zero target is no longer in force after the next general election in 2029. It places greater emphasis on reducing the cost of electricity for end-users through a larger role for nuclear and gas generation, reduced reliance on wind and solar generation, and the removal of policies that require or support the electrification of the economy.

Key policy changes assessed

- Repeal of the Climate Change Act (2008), enabling policy to prioritise minimising electricity costs over reducing carbon emissions.
- Removal of policy support and mandates for the electrification of heat, transport, and industry.
- Discontinued policy support for renewables, energy storage, interconnectors, and other low-carbon technologies from 2030.
- Removal of the GB power sector from the UK Emissions Trading Scheme (UK ETS) from 2031 and introduction of new cross-border electricity trading arrangements.
- End of RO payments for wind and solar technologies from 2033.
- Policy support to enable an increased rate of deployment for gas-fired and nuclear capacity, alongside support to accelerate data centre loads.
- Reduced electricity network expansion.

1) APP is an illustrative policy scenario developed by Onward to test the implications of specified policy changes; it is not a forecast of future Government policy.

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Key takeaways

Between 2030 and 2050, APP results in £320bn of lower modelled power system costs than BAU, alongside 524 Mt higher cumulative domestic power-sector CO_2 emissions. This demonstrates a material trade-off in energy policy between the prioritisation of cost and emissions in both policy pathways.

1. **Impact on power consumption (2030 – 2050):** APP sees slower electricity demand growth caused by the removal of policies that finance or mandate electrification, resulting in -7% (575 TWh) less cumulative consumption between 2030 and 2050. The total change is modest as data centres replace lost demand in other categories. Demand from heat and transport continues to grow, supported by lower electricity costs, but at a slower rate than BAU.

2. **Impact on costs (2030 – 2035):** APP total system costs per unit of electricity are on average -17% lower than BAU in 2035 (-21% lower than 2027 levels), resulting in £44bn in cumulative savings, primarily driven by the removal of the UK ETS in 2031, the early removal of RO payments for wind and solar from 2033, and a reduced rate of network expansion.

3. **Impact on costs (2030 – 2050):** APP total system costs per unit of electricity are on average -20% lower than BAU in 2050 (-31% lower than 2027 levels), resulting in £320bn in cumulative savings. This is driven by lower system costs achieved through the expansion of gas and nuclear capacity in lieu of intermittent renewables, flexible capacity, and other low carbon technologies.

4. **Impact on carbon emissions (2030 – 2050):** APP's average carbon intensity is +64 gCO_2/kWh higher relative to BAU on all electricity produced between 2030 and 2050, resulting in a cumulative increase of +524 Mt in power sector carbon emissions by 2050. The increase in both total emissions and average carbon intensity is explained by the expansion of gas-fired capacity and increased generation.

5. **Total change in carbon intensity by 2050:** APP's average carbon intensity reaches 92 gCO_2/kWh in 2050, representing a +6% increase from 2027 levels. The total change from 2027 levels is limited through downward pressure from a greater rate of nuclear expansion.

1) All monetary values are stated in real 2025 values. 2) All figures stated are rounded to the nearest whole number. 3) Emissions exclude impact outside of the power sector and relate to domestic generation only. 4) System cost savings have been pro-rated to account for lower electricity consumed under APP.

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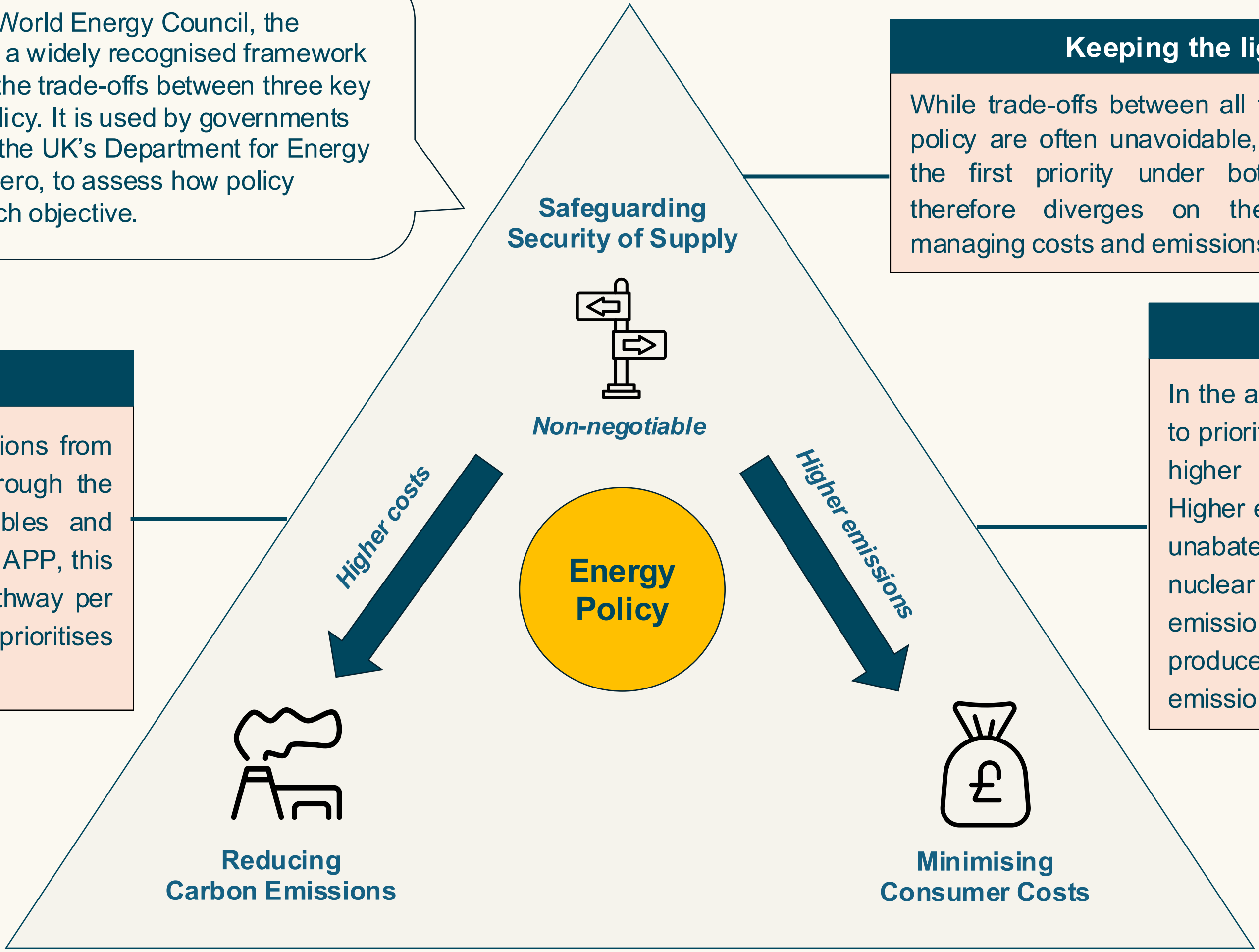
The energy trilemma framework illustrates the inherent trade-off between the two policy pathways

Developed by the World Energy Council, the energy trilemma is a widely recognised framework for understanding the trade-offs between three key goals of energy policy. It is used by governments globally, including the UK's Department for Energy Security and Net Zero, to assess how policy choices impact each objective.

BAU

BAU seeks to eliminate net emissions from the power sector at least cost through the expansion of intermittent renewables and flexible energy sources. Relative to APP, this results in a higher system cost pathway per unit of electricity produced and prioritises decarbonisation over cost.



Keeping the lights on

While trade-offs between all three goals of energy policy are often unavoidable, security of supply is the first priority under both scenarios. Policy therefore diverges on the balance between managing costs and emissions.

APP

In the absence of a net zero target, APP seeks to prioritise cost minimisation at the expense of higher overall emissions, relative to BAU. Higher emissions are driven by the expansion of unabated gas. The increased growth rate of nuclear also exerts downward pressure on emissions at a lower cost per unit of electricity produced. However, any downward pressure on emissions occurs at a slower pace.

Scenarios modelled aim to reflect realistic impacts from a change in policy

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BAU
Current policies with realistic delivery

- The Business as Usual scenario reflects the prevailing UK policy framework and Transira's independent view of likely market developments, taking account of real-world delivery constraints.
- While current Government policy seeks to achieve a clean power system by 2030, BAU does not see this target being achieved until 2045.
- The shortfall on decarbonisation progress against policy ambition reflects the unprecedented scale and pace of investment required across generation, electricity networks, storage and other sources of flexibility, alongside practical constraints relating to planning and consenting, supply chains, skilled labour, financing and grid connections.
- BAU continues to see significant growth in intermittent renewables, alongside energy storage, flexible generation and other emerging low-carbon technologies to support system operation and security of supply.
- Electricity demand grows through continued policy driven electrification of heat, transport and industry.

APP
A change in government and policy from 2029

- The Alternative Policy Pathway begins in 2029, with timing based on an assumed change in government at the next UK general election. The scenario reflects an alternative policy framework developed by Onward, with Transira independently modelling its implementation.
- The Climate Change Act 2008 is repealed and policy shifts to prioritise affordability over decarbonisation of the power sector.
- APP ceases policy-led expansion of intermittent renewable generation from 2030 and implements policies that enable a higher rate of nuclear capacity deployment, alongside reforms that allow for the growth of unabated gas generation to provide firm power.
- The electricity generation sector is removed from the UK Emissions Trading Scheme with new cross border trading arrangements in 2031.
- Policy support and mandates for electrification are removed from 2030, however, the growth of data centre deployment is supported. While overall electricity demand growth is slower than BAU, it continues to rise over the long term driven by lower electricity prices, which strengthen the economic case for electrified alternatives.

Transira's analysis covers six key cost categories that make up over 80% of the average household bill

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Wholesale electricity: Electricity volumes sold in advance over power exchanges and bilaterally to energy suppliers.

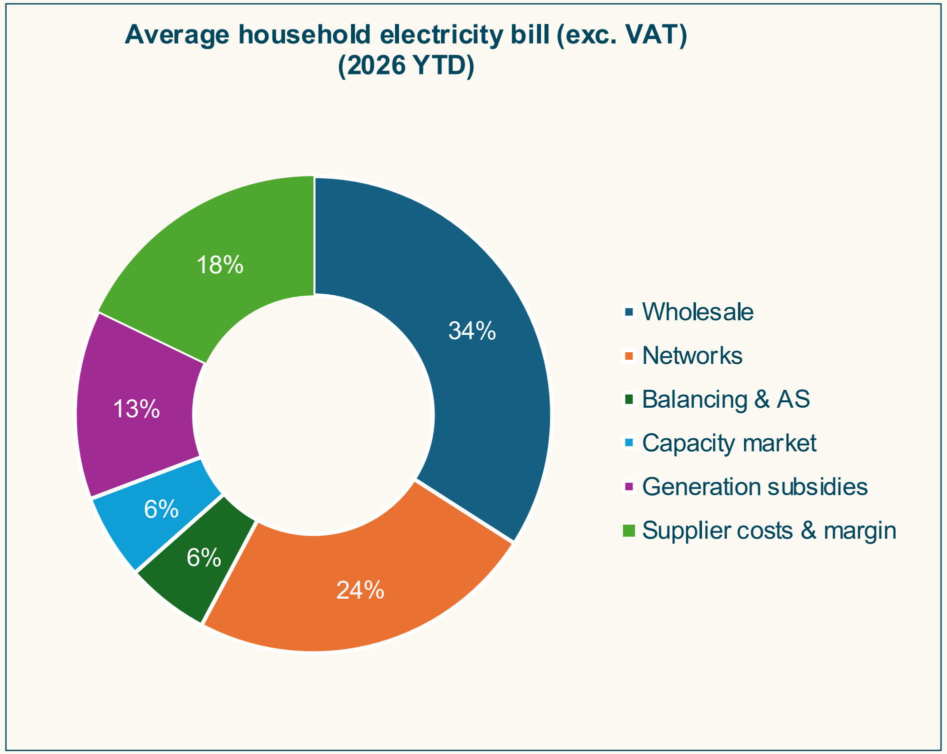
Balancing costs: Electricity volumes sold to the electricity system operator (NESO) in real time to manage demand and supply fluctuations, network congestion, and other critical conditions such as voltage, and inertia.

Networks: Infrastructure charges passed through to consumer bills to maintain and expand high voltage transmission networks, low voltage distribution networks, offshore networks, and interconnector subsidies.

Ancillary services (AS): Various electricity services sold to the electricity system operator (NESO) in advance for balancing, energy security, and other critical operations.

Generation subsidies: Levies on consumer bills to directly fund low-carbon electricity production and capacity market costs.

Capacity market: Levy on consumer bills to directly fund fixed availability payments for dispatchable power plants, in exchange for security of supply guarantees.



Supplier costs excluded from scope.

Source: Ofgem and https://www.electricitybills.uk/ and is calculated as a locational GB average for 3100 kWh single rate metering household. Supplier costs and margins and VAT are excluded from the scope of this report.

APP sees £320 billion in cost savings and emits 524 Mt more carbon over 20 years

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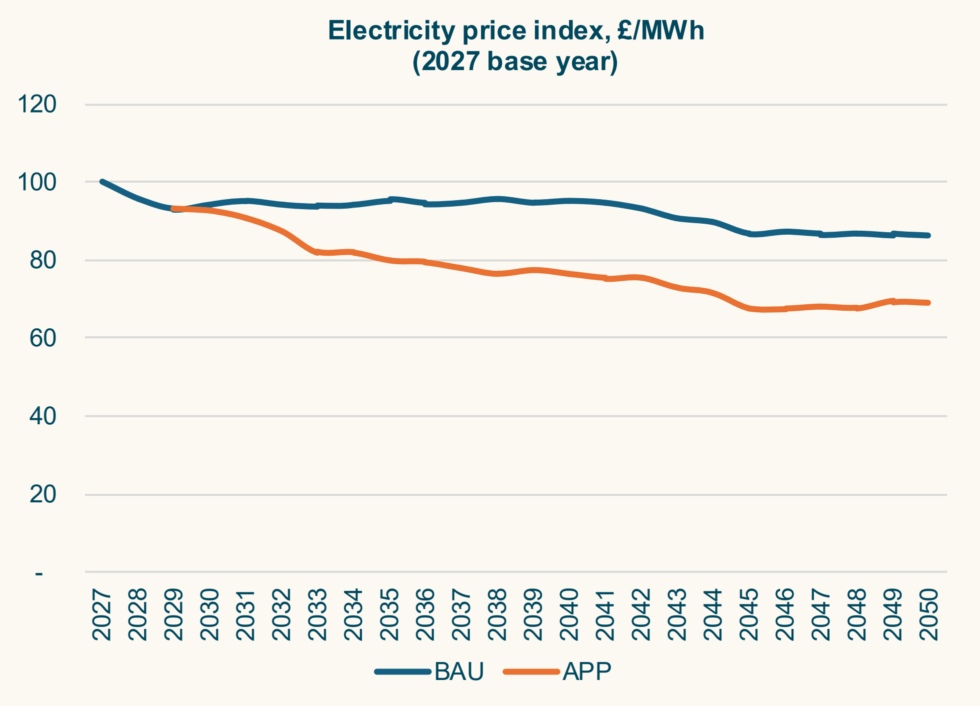
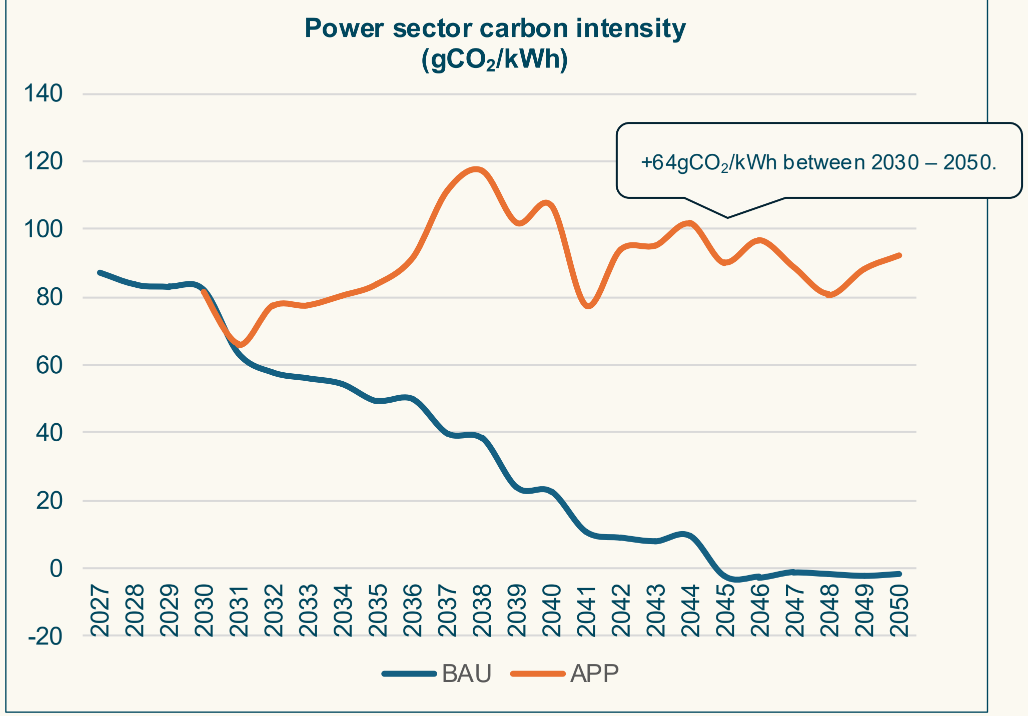
Cost impact



Emissions impact



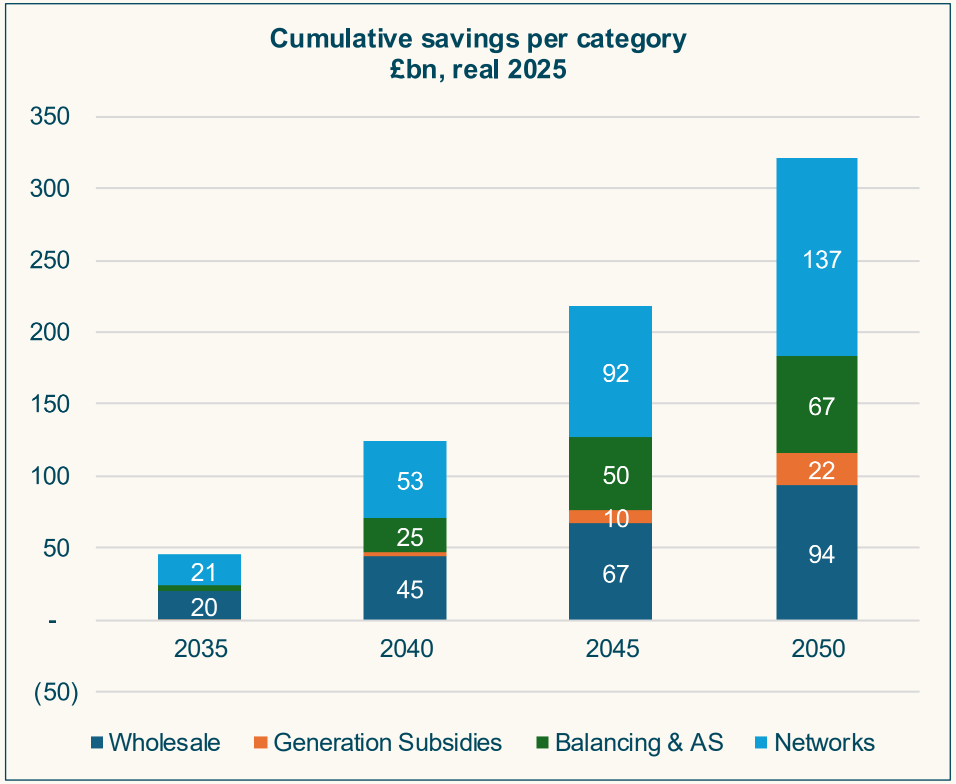
APP reaches £44 billion in cumulative savings on power consumed by 2035, rising to £320 billion by 2050.

APP sees a 33 Mt increase in cumulative carbon emissions on all production to 2035, rising to 524 Mt by 2050.

1) Emissions impact excludes emissions outside of the power sector and relate to domestic generation only. 2) 1Mt = 1 million tonnes. Cost index excludes VAT and downstream supplier costs. 3) GWA = Generation weighted average.

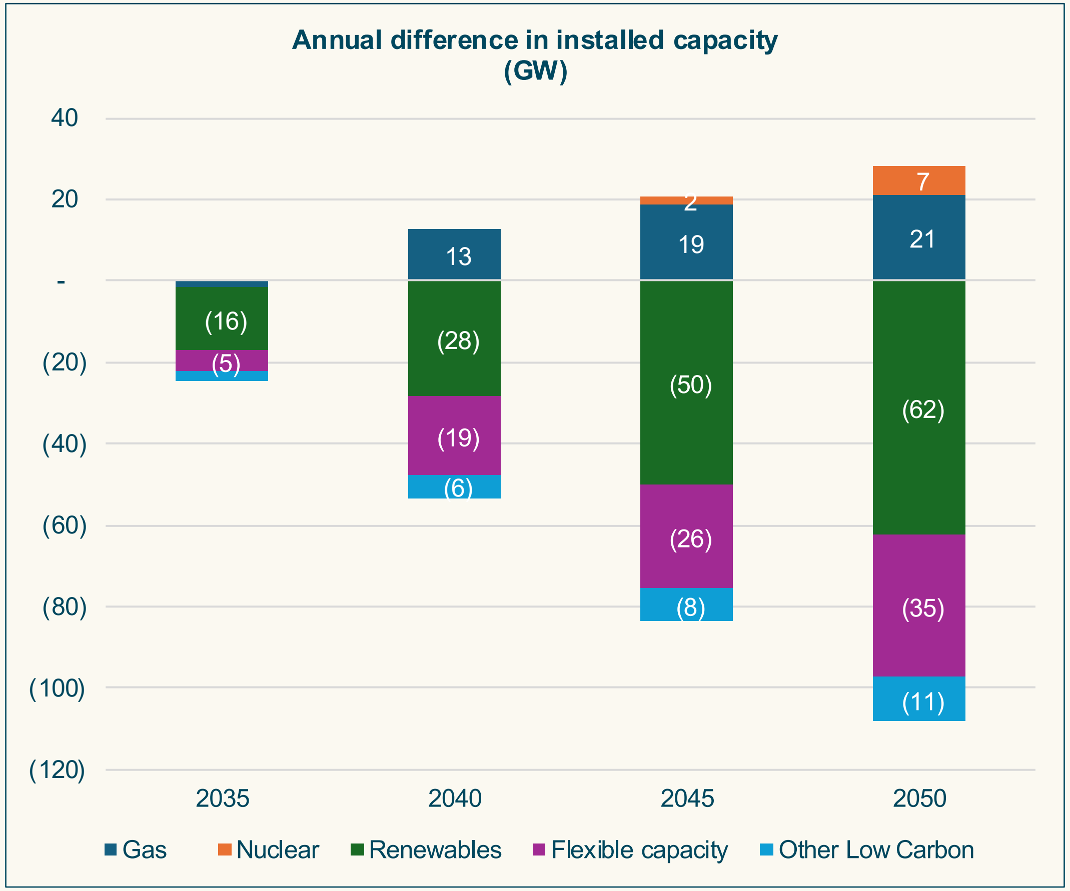
£320 billion is saved across four key areas of the power system by 2050

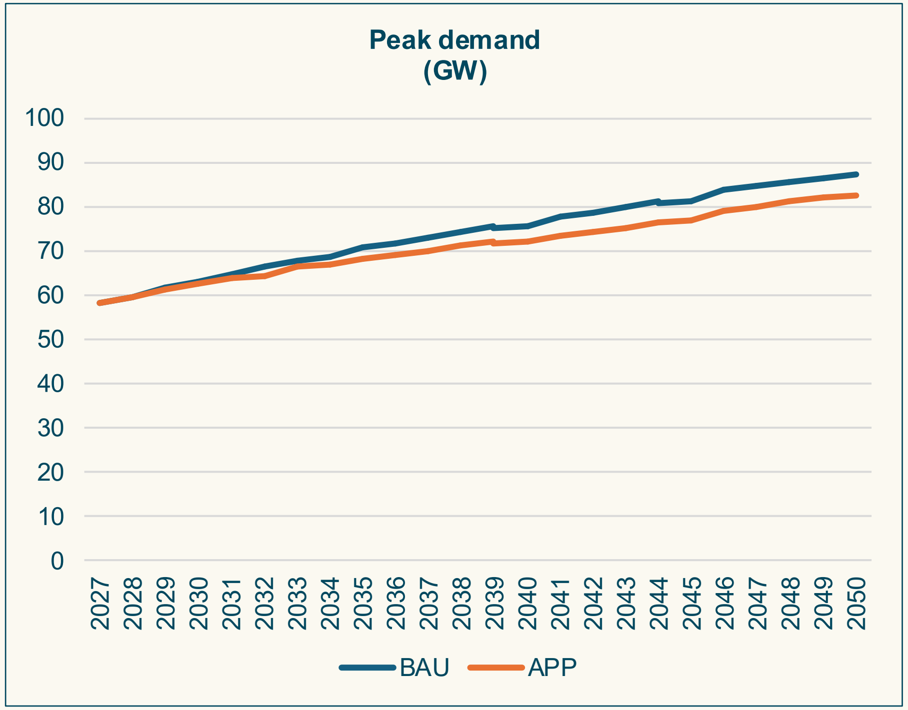
- **Networks:** By 2050, APP's peak demand is ~4.5 GW smaller than BAU, however installs ~80 GW less capacity, which enables material savings on network expansion. This is achieved by moving from a decentralised and geographically dispersed energy system to a centralised energy system with lower network requirements.
- **Wholesale electricity:** Net decrease in electricity prices through the removal of UK ETS carbon prices from all generation.
- **Generation subsidies (inc. capacity market):** Overall reduced government spending by switching spend on intermittent renewables and low-carbon flexible generation to gas and nuclear.
- **Balancing and ancillary services:** Savings primarily made through reduced spending on thermal constraints and reserve costs. These costs are lower as APP's generation mix requires fewer actions to balance the grid.



Source: Transira. 1) Generation subsidies in the above chart include net losses for the capacity market under APP. 2) All figures are rounded to the nearest whole number.

By 2050, APP's peak demand is 5% lower, but its total installed capacity is 33% lower by switching to firm power



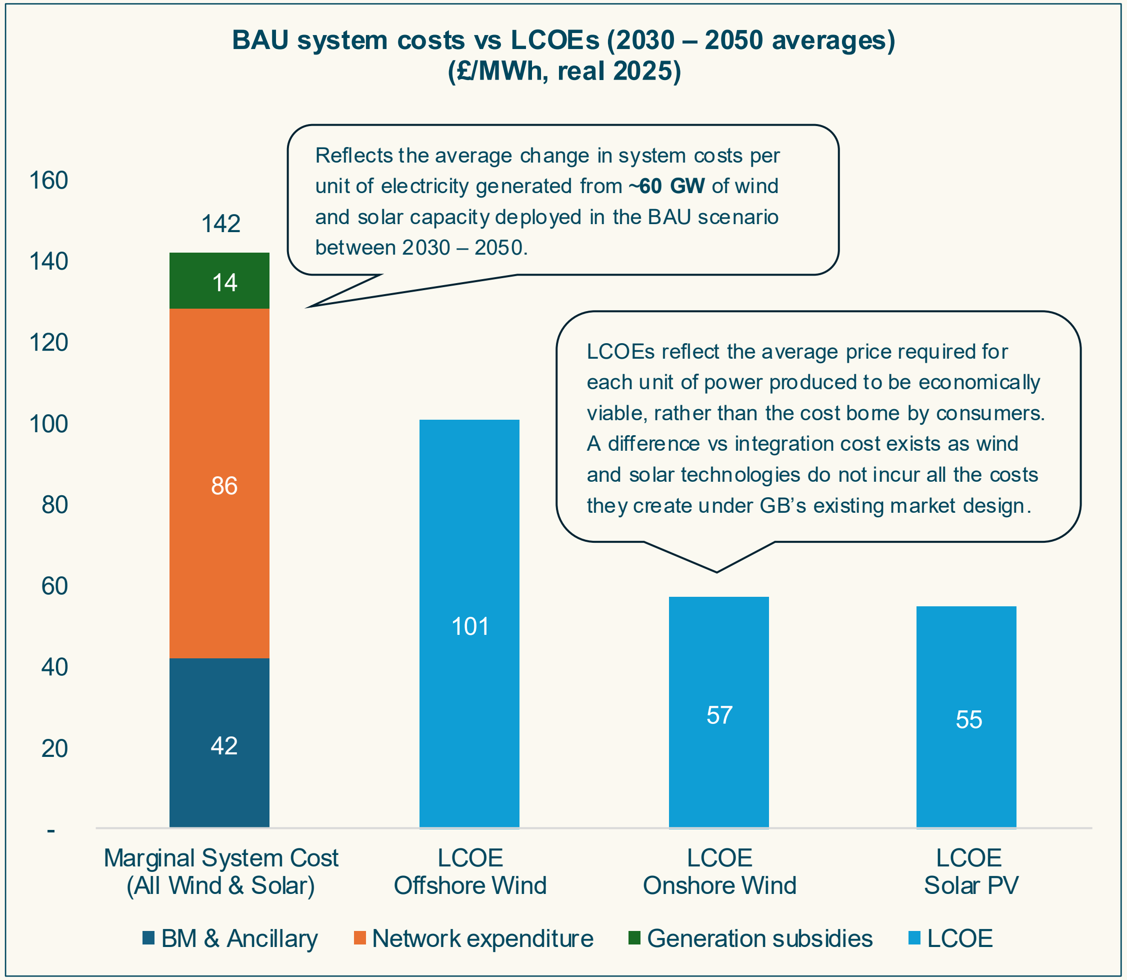


- By 2050, APP has ~80 GW less installed than BAU despite only a ~4.5 GW difference in peak demand. This is explained by the low utilisation of wind, solar, and flexible technologies. The reduction in installed capacity enables material savings on network expansion.

1) Renewables includes wind, solar PV, and other renewables. Other low carbon includes BECCS, Hydrogen CCGT, and Gas CCS. Flexible capacity includes BESS, pumped storage, interconnectors, and DSR.

APP avoids ~£142/MWh of incremental system costs associated with wind and solar deployment in BAU

- **Under current GB market arrangements, many system costs associated with integrating additional wind and solar output are recovered from electricity demand and are not fully reflected in project LCOEs or CfD strike prices.**
- **Network costs**: While locational network charges are intended to be cost reflective, they act as a relative price signal to incentivise behaviour rather than recover the monetary value of incremental network expenditure. Approximately 70 - 90% of transmission network costs are recovered from demand. Additionally, Intermittent generation does not bear the incremental network expenditure for connecting other technologies required for the integration of its production, including energy storage and flexible capacity.
- **Balancing & Ancillary costs:** 100% of costs are recovered from demand via BSUoS charges. This includes payments for lost generation at CfD strike prices, the cost of replacement energy, energy-balancing costs arising from supply volatility, and associated costs for reserve, response and voltage management.
- **Generation subsidies:** Increased spend on additional subsidies to other technologies to compensate for intermittency.
- **Carbon prices:** While wind and solar exert downward pressure on wholesale prices, the inclusion of carbon prices leads to a net increase in wholesale prices.



Sources: Transira, DESNZ, NESO. 1) £142/MWh represents the modelled average incremental system cost difference associated with the difference in wind and solar generation in BAU relative to APP over 2030–2050. It is calculated as the change in cumulative system costs divided by the corresponding change in wind and solar output. Actual cost impacts from wind and solar deployment can vary with location, technology, timing of deployment, co-location of other technologies, network conditions, demand, market design and the wider generation mix. 2) Generation subsidies in the above chart include net losses in the capacity market under APP.

APP total power sector emissions increase by 524 Mt between 2030 and 2050

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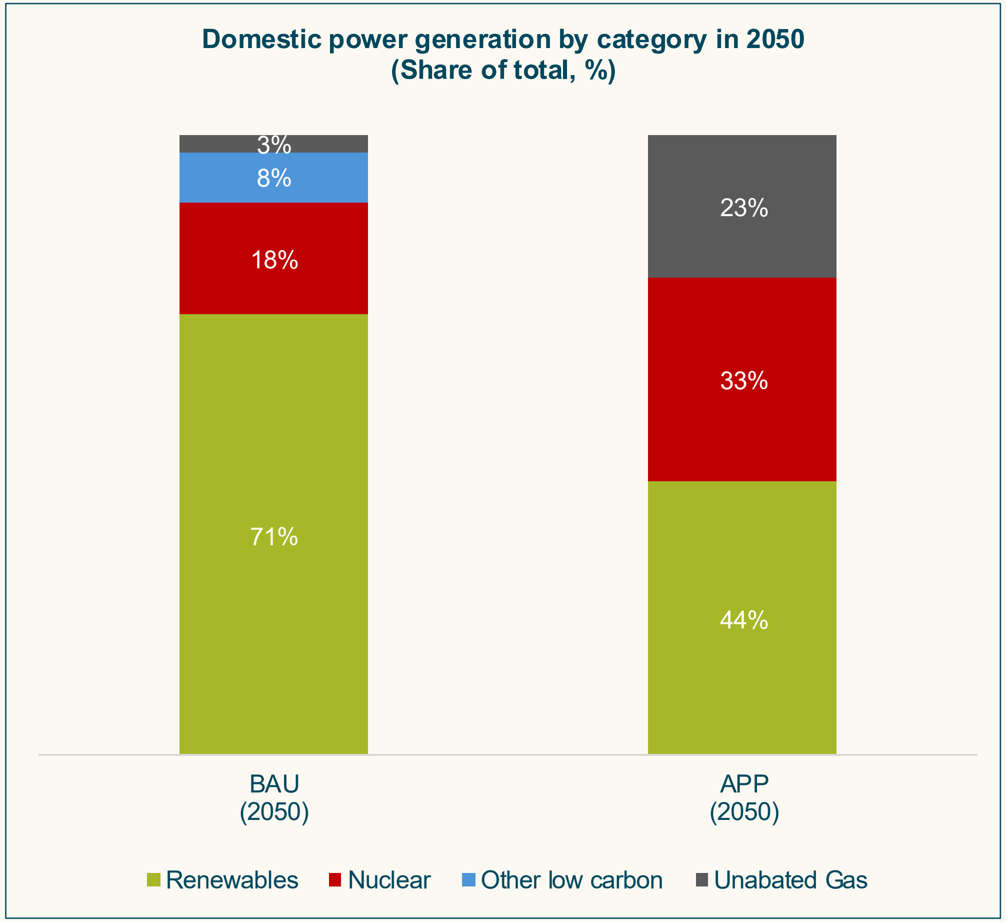
- APP's average carbon intensity increases by 64 gCO_2/kWh on total electricity produced between 2030 and 2050, resulting in a total increase of +524 Mt in power sector emissions by 2050.
- The increase in both total emissions and average carbon intensity is explained by an increased share of unabated gas-fired capacity which represents a +20p.p. difference by 2050.
- The share of nuclear generation is 15p.p. greater in APP which offsets the growth in unabated gas generation and sees APP's total carbon intensity reach 92 gCO_2/kWh in 2050, representing a +6% increase from 2027 levels.



Sources: Transira. 1) Share of generation chart excludes interconnector flows and energy storage to explain carbon emissions. 2) Other low carbon includes BECCS, Hydrogen CCGT, DSR, and Gas CCS. Renewables include all wind and solar technologies, biomass, waste, hydro, landfill gas, and other RES technologies. 3) All figures are rounded to the nearest whole number. 4) Emissions stated relate to domestic generation only.

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Transira combines independent research, PLEXOS modelling, and internally consistent analysis to evaluate costs and emissions

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Transira uses data and inputs for modelling from various data providers and recognised official sources, supplemented by independent research and analysis. PLEXOS is used for simulating dispatch and price formation which incorporates the evolution of supply and demand. The power sector capacity mix evolves over time using both policy-defined capacity assumptions, build constraints, and endogenous investment and retirement decisions.

Scenario Inputs

Key modelling inputs reflect each scenario:

- Electricity demand
- Natural-gas prices
- Carbon tax prices
- Policy support for specific technologies
- Technology build costs
- Build rates / limitations
- Weather patterns

PLEXOS Simulation

PLEXOS simulates various elements, including:

- Operation of wholesale electricity markets at hourly granularity
- Retirements of existing plant
- Endogenous decisions for build of new plant

PLEXOS Outputs

Key outputs include:

- Wholesale prices
- Generation mix
- Emissions
- Capture prices
- Load factors
- Generator earnings (NPV)

System Costs Modelling

PLEXOS outputs drive the modelling of wider system costs on a consistent basis, including:

- Ancillary services expenditure
- Network expenditure
- Capacity and balancing market costs
- Subsidy costs

1) Generation calculated in PLEXOS excludes line losses.

Transira uses in-house modelling of power demand and wider system costs

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Power Demand

- Power demand has been modelled by separating underlying consumption from additional demand associated with electrification and new large loads.
- Annual demand projections are then converted into technology-specific hourly profiles for use within the PLEXOS.

Ancillary services

- Ancillary services and other balancing costs are modelled using historical system data from NESO and scenario-specific assumptions on the generation mix, demand profile and commodity-price environment.
- This includes reserve, response, voltage and other operability services.

Network expenditure

- Transmission and distribution network totex is calculated under a RAB recovery model consistent with the price control framework.
- Totex expenditure reflects Transira’s assessment of the scale, timing and deliverability of network expansion under each pathway.

Generation subsidies

- Existing expenditure is calculated at asset level using contractual terms and modelled generation for FIDER, CfD, RO, FiT schemes.
- Future support costs are modelled using technology specific LCOEs published by DESNZ, applied consistently with generation and wholesale earnings produced by PLEXOS in each scenario.

Capacity market auctions

- Existing expenditure is based on published auction results through 2027.
- Future auction volumes are modelled using PLEXOS outputs, including peak demand, existing capacity, and expected plant revenues. Future clearing prices are solved to allow marginal capacity to achieve its required rate of return.

Energy balancing and thermal constraints

- Energy balancing and thermal constraint costs are modelled in PLEXOS and have been calibrated against NESO’s published outlook for constraint volumes and cost, and the realised deployment rate of capacity contributing to thermal constraints in BAU and APP.

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APP implements a suite of policy changes from 2030

	Policy Area	BAU	APP
1	**Power demand**	▪ Support mechanisms continue for the electrification of heat pumps, transport, industry, and hydrogen.	▪ All support mechanisms and mandates for electrification are removed. ▪ Support for hydrogen electrolysis is removed. ▪ Data centre permitting and connections prioritised to accelerate deployment.

2	**Future RES and low carbon subsidies**	▪ RO and FiT payments continue until planned expiry in 2037
		▪ Continued procurement of renewable technologies through contracts for difference allocation rounds
		▪ Growing procurement of LDES and interconnectors under existing cap and floor schemes
		▪ Anticipated implementation of new support schemes for the deployment of hydrogen and CCS technologies.
			▪ Early retirement of RO payments for wind and solar technologies from 2033.
			▪ No further government support for new intermittent renewables and other technologies which cease growth in:
			    ▪ Wind, solar and other RES
			    ▪ Interconnectors
			    ▪ LDES
			    ▪ CCS technologies

3	**Nuclear subsidies**	▪ Continued procurement of nuclear under RAB scheme	▪ Continuation of RAB scheme. ▪ Targeted support to accelerate and increase nuclear deployment.
4	**Carbon pricing**	▪ UK ETS retained	▪ UK ETS removed from 2031. ▪ Lower TNUoS charges considered for pre-existing offshore wind CfD plants after CfD expiry to avoid early economic retirement.
5	**Capacity market**	▪ Agreements continue at 15 years. ▪ Decreasing auction targets as capacity is increasingly procured through other support mechanisms.	▪ Agreements extended from 15 to 20 years. ▪ Increasing auction targets to meet growing demand. ▪ Removal of new-build interconnectors in auctions.
	Networks	▪ High network expansion driven by growing total capacity and greater de-centralisation of capacity.	▪ Reduced network expansion driven by reducing total capacity and greater centralisation of capacity.

X Deep dive on following slides

1) Carbon Price support ceases in both scenarios from 2028.

1

Demand deep dive: APP reduces policy-driven electrification demand while maintaining support for strategic data centre growth

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Demand growth in APP is driven increasingly by cost driven electrification and government support for strategic industrial loads rather than policy-driven electrification of the economy

Demand category	BAU	APP	APP Impact
Transport	Ban on sale of new ICE vehicles from 2030 supports EV uptake.	ICE vehicle ban 2030 reversed, reducing EV adoption despite lower electricity costs.	⬇
Heating	Continued support for heat pump deployment (e.g. Boiler Upgrade Scheme), CHMM.	Heat pump subsidies and mandates removed. Lower electricity costs drive growth at a slower rate than in BAU.	⬇
Hydrogen production	Electrolysis supported through policy and subsidies.	Electrolysis hydrogen demand falls to zero from 2030.	⬇
Data centres	Growth supported by policy for permitting and prioritisation of grid connections.	Strong growth supported by grid reinforcement and connection prioritisation.	⬆
Base demand	Modest increase driven by population growth.	No change assumed versus BAU.	

⬆ = Increase vs BAU

⬇ = Decrease vs BAU

Sources: NESO, DESNZ, Transira. 1) Heating in the BAU is supported by the Clean Heat Market Mechanism, which runs until at least 2029. 2) Strong growth in data centre demand is facilitated by prioritisation for as much of the circa 50 GW of projects currently in the connection queue requesting capacity. Localised transmission bottlenecks need to be resolved over time, and new data centre projects can have around 4 years to move to needing power to test before full operation. This means that data centre demand will increase progressively. 3) For hydrogen, we assume ~10 GW equivalent demand in 2050, much later than the current policy target of at least 5 GW electrolytic hydrogen by 2030 given the immaturity of the sector, the competition for new grid connections and weak hydrogen off-take demand. APP sees demand cease after 2030 as HAR CfD funding is ceased and grid connection policy favours data centres.

2

Subsidies deep dive: APP ends RO payments for wind and solar in 2033, and ceases new support under other schemes

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Renewables Obligation payments cease for wind and solar from 2033

- APP ends support under the Renewables Obligation for all wind and solar technologies from 2033, and offshore wind under RO payments is assumed to exit the market from this point onwards.
- Three years' notice allows new capacity to come forward, helping to ensure any required capacity is maintained to replace any early closure of capacity.
- Large scale biomass owned by Drax will transition from the RO to a low-carbon dispatchable CfD under both BAU and APP for April 2027 – March 2031. This recognises the importance of its contribution to generation and to system stability.

The Contracts for Difference scheme is discontinued from 2030

- The CfD scheme ends in 2030, which sees no further growth in intermittent renewables and other low carbon technologies under the scheme, which includes:
  - Offshore wind
  - Onshore wind
  - Solar PV
  - Other low-carbon technologies.
- APP does not introduce any replacement support for retiring CfD or RO capacity.
- No change to pre-existing CfD contracts.

Multiple existing and planned support schemes for other low carbon and flexible technologies are discontinued from 2030

- Existing schemes include cap-and-floor schemes for LDES and interconnectors.
- APP discontinues support for less mature and nascent low-carbon technologies including:
  - Hydrogen-fuelled plant
  - Hydrogen electrolysers
  - Gas with carbon capture and storage (CCUS)
  - Bioenergy with Carbon Capture and Storage (BECCS)
  - Long-duration energy storage (LDES)
- No change to pre-existing contracts for all other support schemes.

Nuclear deep dive: APP builds ~7 GW more nuclear capacity by 2050 as nuclear becomes the government's priority

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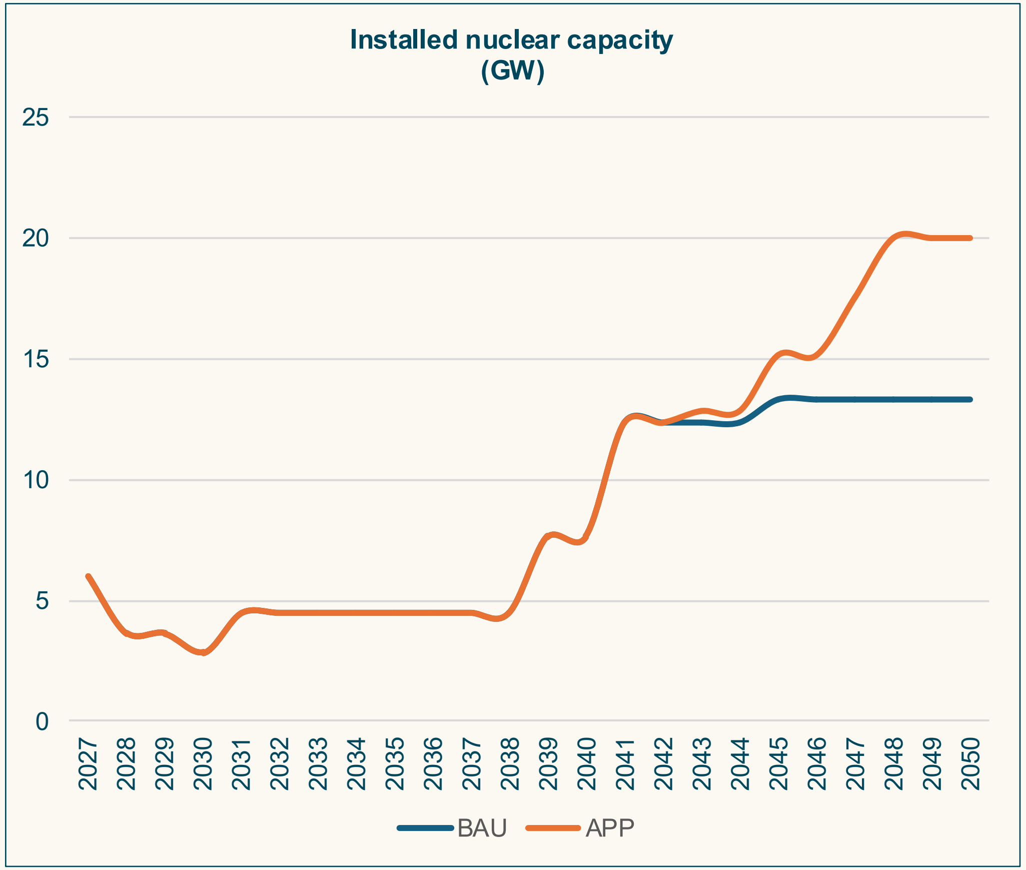
APP policy increases site readiness, reduces development timescales, and prioritises connections for new nuclear

- BAU pursues nuclear build out but does not devote sufficient resources and policy focus to overcoming institutional and delivery-related barriers to nuclear development in GB.
- In APP, there is greater government bandwidth to enable higher nuclear deployment, following the cancellation of multiple government support schemes. Reducing nuclear construction costs and accelerating deployment becomes the core energy priority of the UK government in APP, which introduces reforms aimed at streamlining planning and regulatory processes to tackle the current barriers to nuclear development.
- Great British Energy is funded to buy nuclear sites and reserve grid capacity under powers granted by the Planning and Infrastructure Act. Time is saved by providing nuclear developers with a series of turnkey project sites that are ready for construction start.
- To allow new nuclear to connect quickly, reservation of grid connections would be secured under section 165A of the Energy Act 2023.



Source: Transira. 1) Nuclear barriers as discussed in the Nuclear Regulatory Review 2025 led by John Fingleton. 2) Reservation of grid connections as described in the consultation 'Accelerating electricity network connections for strategic demand' and as inserted by section 18 of the Planning and Infrastructure Act. APP nuclear build-out has assumed the use of sites suitable for new stations as stated in the National Policy Statement for Nuclear Energy Generation (EN-7). These sites include Sizewell, Wylfa, Trawsfynydd, Sellafield, Hartlepool, Heysham, Bradwell, Hunterston, Oldbury, Moorside and Torness. Capacity from new Small and Modular Reactors (SMRs) is also assumed in the APP and could be developed on a wider range of sites compared to those stated in the NPS.

4

Carbon deep dive: APP removes UK ETS from 2031 and implements a carbon reference price for power exports

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The power sector is removed from the UK ETS in 2031

- The UK ETS is removed from 1 January 2031 with the aim of lowering the wholesale price of electricity.
- Its removal directly reduces the production cost of all carbon emitting plants which frequently set wholesale prices under a marginal pricing system.
- Cost savings are subsequently made across all power generation exposed to the wholesale price that is not compensated under a fixed-price subsidy scheme (e.g. contracts-for-difference).
- Cost savings are not made on plants under a CfD contract, as subsidy payments increase to match contracted strike prices.

A Carbon Reference Price is introduced for exports to prevent carbon leakage to the EU

- A 'Carbon Reference Price' is introduced for electricity sold to the European Union to prevent carbon leakage and the distortion of cross-border electricity flows.
- The Carbon Reference Price introduces an effective 'top-up' price for electricity purchased by countries operating under the EU ETS.
- Implementation is assumed by automatically applying the reference price to all wholesale market clearing prices for buyers of GB electricity on relevant day-ahead and intraday electricity exchanges.
- The Carbon Reference Price is assumed to be set monthly by the UK Government. It is calculated by applying the prevailing EU ETS allowance price to the assumed emissions intensity of a representative unabated gas-fired generator.

Network charges adapted to avoid early closure of pre-existing CfD plants

- Under APP, lower wholesale prices directly reduce revenues for all plants exposed to merchant wholesale prices.
- For offshore wind plants in particular, this may be to the extent that they are no longer able to cover their fixed costs of generation in the absence of subsidy support in the form of a CfD, in part driven by high TNUoS charges.
- APP assumes that a review of network use charges will be undertaken with a view to adapting network use tariffs in a targeted manner, to allow expiring offshore wind CfD generators to cover their costs and continue to generate after CfD expiry.

1) The approach for the calculation of the Carbon Reference Price is analogous to the reference-plant methodology used in BEIS' proposed 'Dispatchable Power Agreement' variable-payment mechanism for CCUS technologies, which calculates carbon-cost differentials against an unabated reference plant.

5

APP increases support through the capacity market for dispatchable generation

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Capacity market reforms support new gas plant and remove interconnectors

- Capacity market contracts are extended to 20 years in APP, compared to 15 years for contracts in BAU.
- This enables investors in new gas projects to have greater certainty of revenue flows over a longer part of the asset life and encourage deployment of new firm generation to meet growing power demand in the APP scenario.
- New-build interconnectors will no longer be eligible to participate in the Capacity Market, while existing interconnectors will continue.

Prioritised grid connection enables gas to deploy quickly and serve growing power demand

- Under APP, new gas-fired generation is assumed to receive priority access to the transmission grid connection queue to accelerate the delivery of firm dispatchable capacity.
- This reflects APP's policy objective of maintaining security of supply by ensuring that new thermal generation can connect as quickly as possible where it is required to replace retiring capacity.
- This assumption is motivated by the significant backlog in the GB grid connection queue, where projects have historically faced connection dates extending well into the 2030s.
- Through its connections reform programme, NESO is replacing the previous "first come, first served" approach with a gated process that prioritises projects demonstrating both strategic system need and delivery readiness.
- APP assumes that new gas-fired generation meeting these criteria is designated as strategically important and receives accelerated access to available network capacity ahead of lower-priority generation projects.

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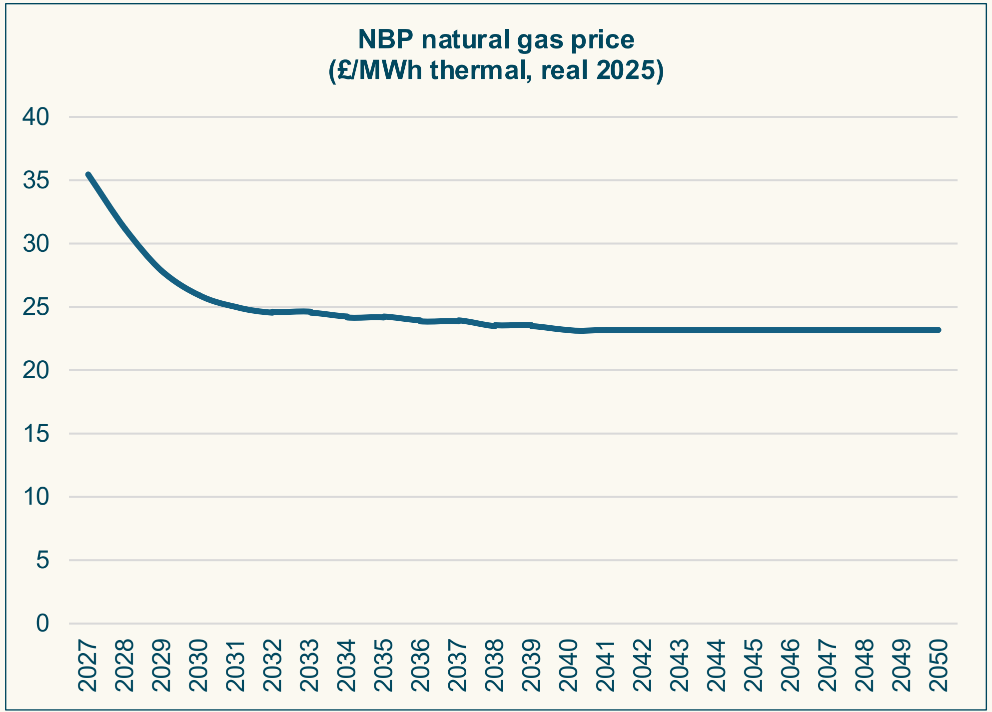
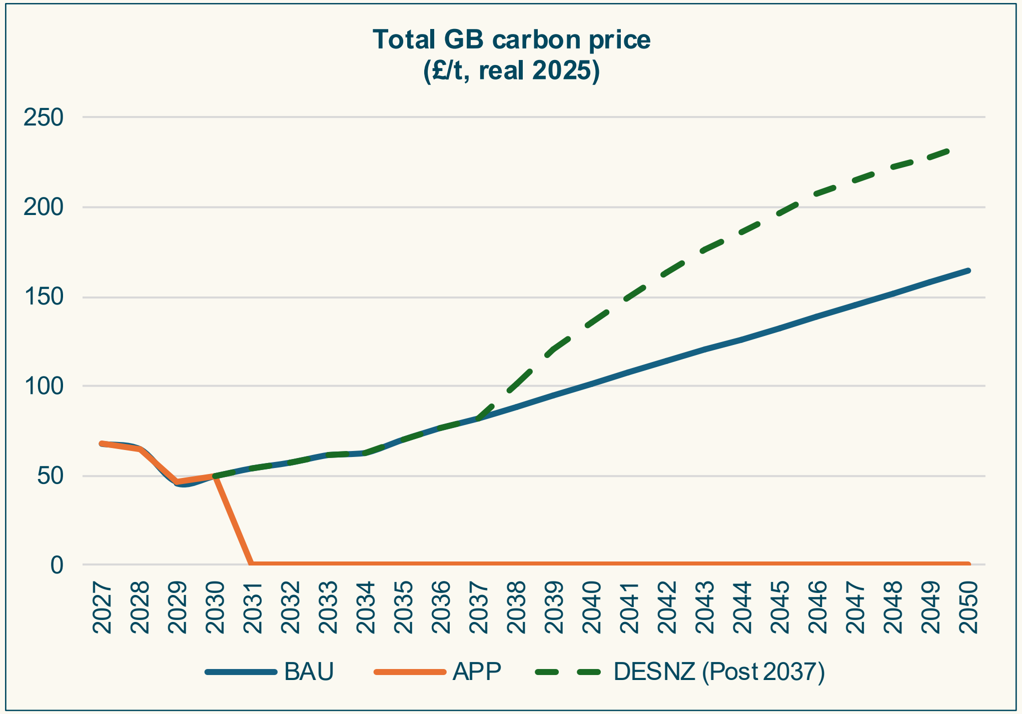
Gas prices are equal in both scenarios; carbon prices diverge following withdrawal of the power sector from the UK ETS



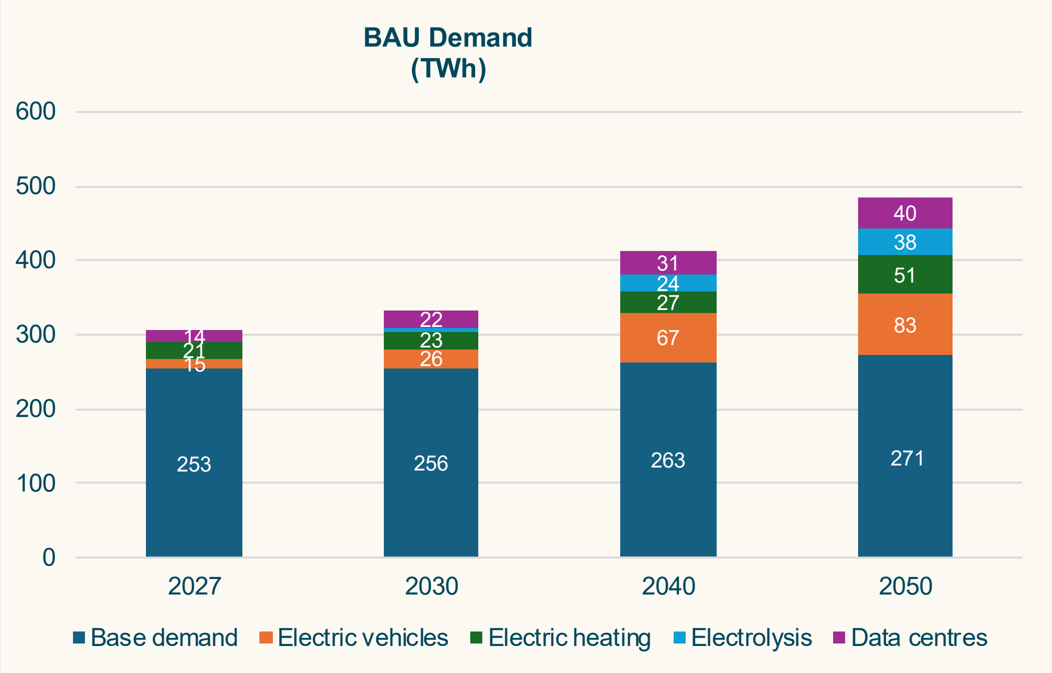
- Gas prices have been blended using values from DESNZ and ICE Futures (taken as of May 2026) until 2030.
- From 2030 onwards, prices are reflected by DESNZ in real 2025 values.
- In all years, gas prices have been profiled at monthly granularity based on research from Transira to reflect seasonal changes in prices throughout the year.

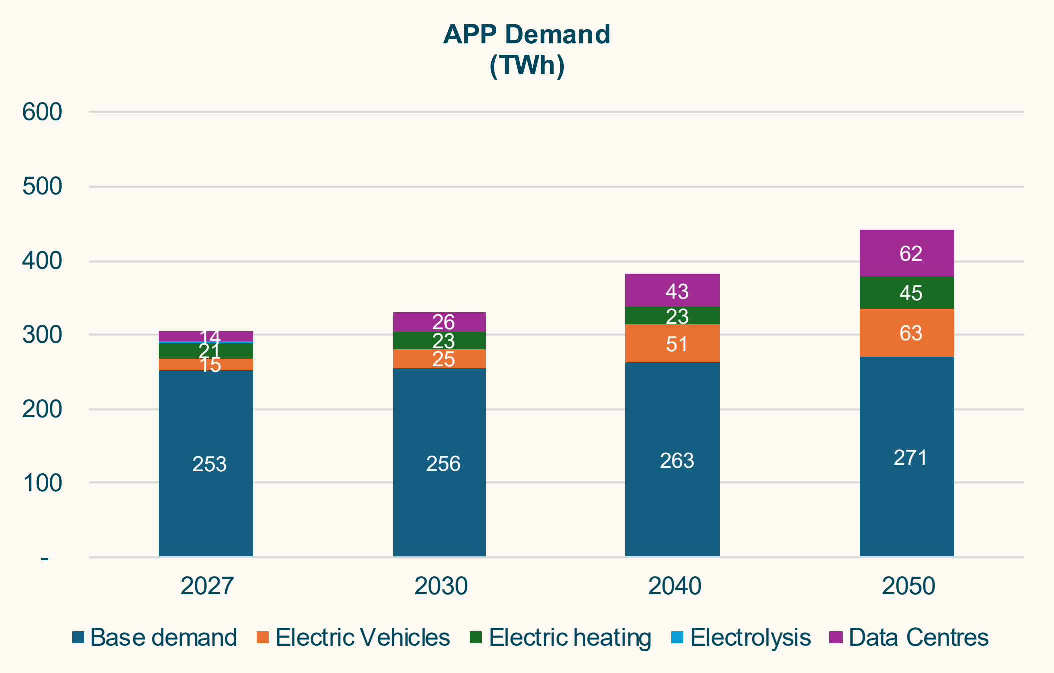


- The GB carbon price reflects the total CPS and UK ETS price. The UK ETS price is removed from 2031 in the APP scenario.
- Until 2030, carbon prices are blended between fundamentally modelled forecast values from DESNZ and UK ETS futures from ICE (taken as of May 2026). Transira assumes a more conservative carbon price than DESNZ from 2037 onwards.

Sources: Transira, DESNZ, ICE. 1) Carbon Price Support is currently £18/tonne CO_2 and is removed from April 2028 in both BAU and APP scenarios.

Total power demand grows faster in BAU driven by electrification policy support, but APP sees strong data centre demand





- BAU power demand grows to **484 TWh** by 2050, driven by support for electrification across heat, transport, and hydrogen production.
- Electric vehicle demand grows materially after 2030, driven by the planned ban on the sale of new petrol and diesel vehicles under current policy. Total EVs reach 42m vehicles in 2050. Heat pump units grow by 7.7m units between 2027 and 2050.

- APP power demand grows to **441 TWh** by 2050, representing 43TWh (~10%) lower consumption versus BAU. Heat and transport growth is lower relative to BAU due to the removal of policy support for electrification, while data centres are higher reflecting the prioritisation for new data centre connections.
- APP assumes the removal of a planned ban on the sale of new petrol and diesel vehicles from 2030, and sees total EVs rise to 32m vehicles in 2050. In addition, APP sees lower heat pump additions than BAU, growing by 6.1m units between 2027 and 2050. By 2050, data centre demand is ~14% of total demand in APP, compared with 8% in BAU.

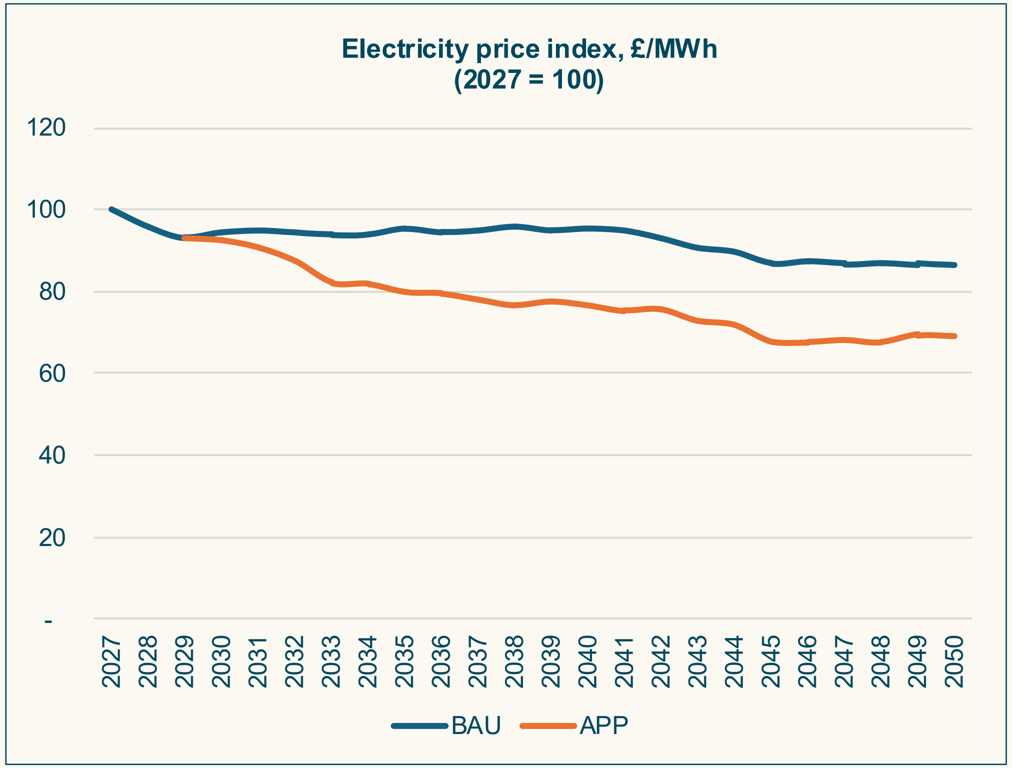
Sources: Climate Change Committee, NESO (FES), Transira. 1) EVs include all forms of fully electric and hybrid vehicles. 2) An EV in a mixed fleet is assumed to consume 2.0 MWh/year/vehicle. 3) Average heat pump consumption assumed is 3.9 MWh/year/unit. 4) All figures are rounded to the nearest whole number.

Technology assumptions

Category	Modelling approach
Asset technical parameters	Technical parameters for each asset class that drives hourly dispatch are based on both proprietary asset level data from Energy Exemplar and research from Transira.
Underlying weather patterns	Weather patterns and their seasonal effects on supply and demand have been provided by Energy Exemplar based on data from ENTSOE (2009).
Existing and pipeline capacity	Existing capacity across all technologies has been defined at asset level based on both proprietary data from Energy Exemplar and independent research from Transira using public data sources, including NESO, Ofgem, and LCCC.
Gas-fired technologies, BESS.	Future growth is determined endogenously by Plexos with lead times and build limits based on research from Transira.
Wind, solar PV, nuclear, DSR, and interconnectors	Continued growth has been exogenously projected by Transira based on the policy parameters of each scenario, taking build constraints into account.
Other low-carbon	Future growth of Gas CCS, BECCS, and hydrogen-fired capacity has been exogenously projected based on the policy parameters of each scenario, and technology readiness.
Asset lifetimes	Asset lifetimes have been based on independent research from Transira for each asset class.

Contents

APP achieves a ~17% saving in average GB costs per unit of electricity produced by 2035, rising to ~20% by 2050

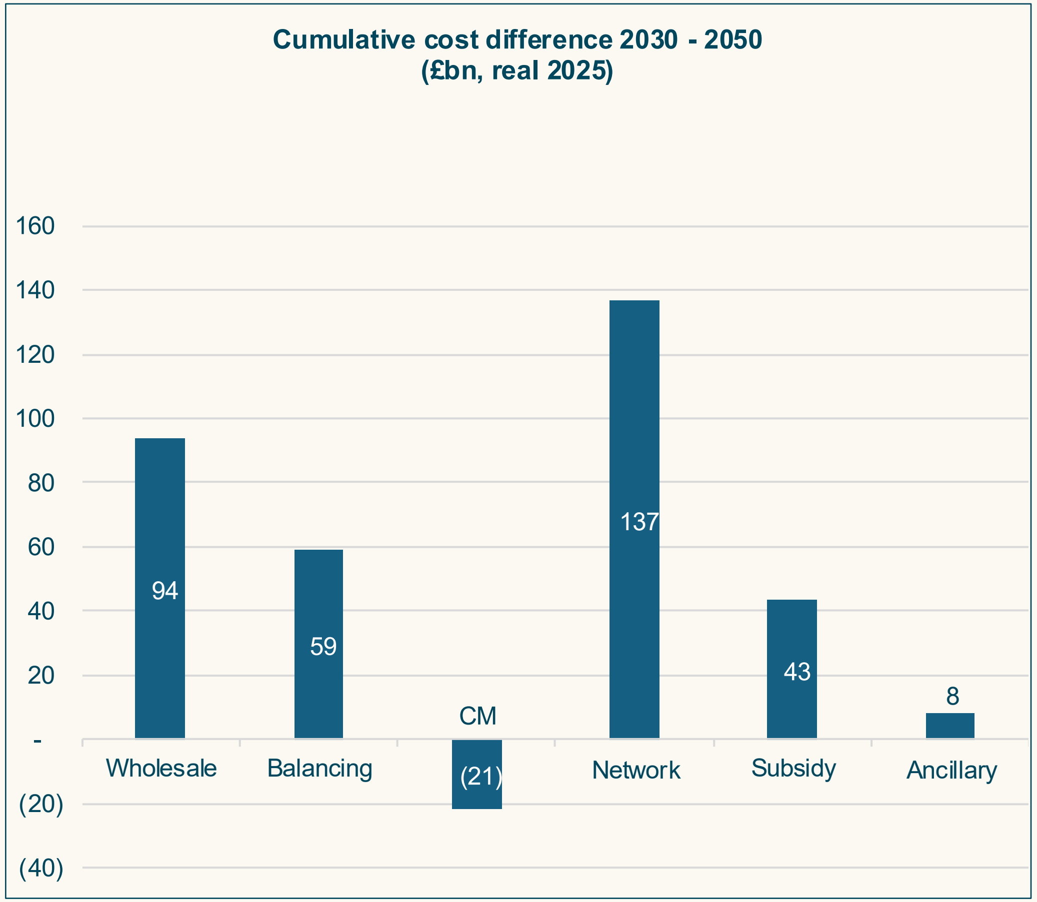


- **2027 to 2030:** Costs in both scenarios decline from 2027 levels to 2030, caused by falling natural gas prices.
- **BAU post 2030:** BAU prices continue to decline after 2030, primarily driven by a growing share of intermittent renewables with declining costs and reflecting declining LCOE assumptions.
- **APP 2030 - 2035:** APP costs decline sharply from 2030, through reduced network spending, the removal of the UK ETS in 2031, and the removal of RO payments for wind and solar capacity from 2033.
- **APP post 2035:** APP sees long-term cost reductions through reduced spending on networks, balancing and ancillary services, resulting from a shift in the underlying technology mix from intermittent renewables to gas and nuclear.

Source: Transira. 1) Electricity prices exclude VAT and downstream supplier costs.

APP sees cumulative system cost savings of £320 bn between 2030-2050

- **Wholesale:** APP reduces wholesale costs primarily through the UK ETS removal.
- **Capacity market (CM):** Total expenditure is higher in APP as it procures more capacity through auctions to meet power demand growth, where BAU procures additional capacity through other schemes.
- **Generation subsidies:** are lower due to the early removal of RO and discontinued support for low carbon technologies, other than nuclear.
- **Balancing and ancillary costs:** are overall lower, driven by reduced intermittent supply, that reduces spending across thermal constraints, energy balancing, and most ancillary services to manage frequency and voltage.
- **Network costs:** are lower in APP as the network does not need to expand to accommodate geographically dispersed wind generation.



Source: Transira

APP's generation mix increases total carbon emissions by 524 $MtCO_2$ between 2030 and 2050

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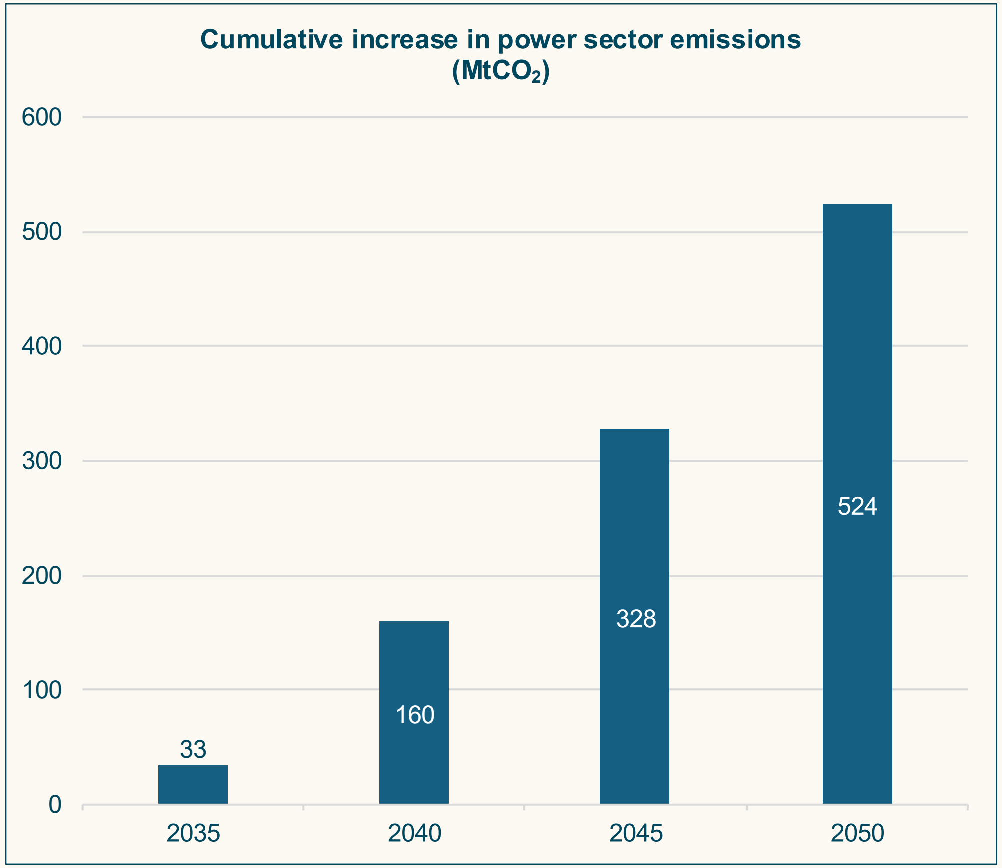
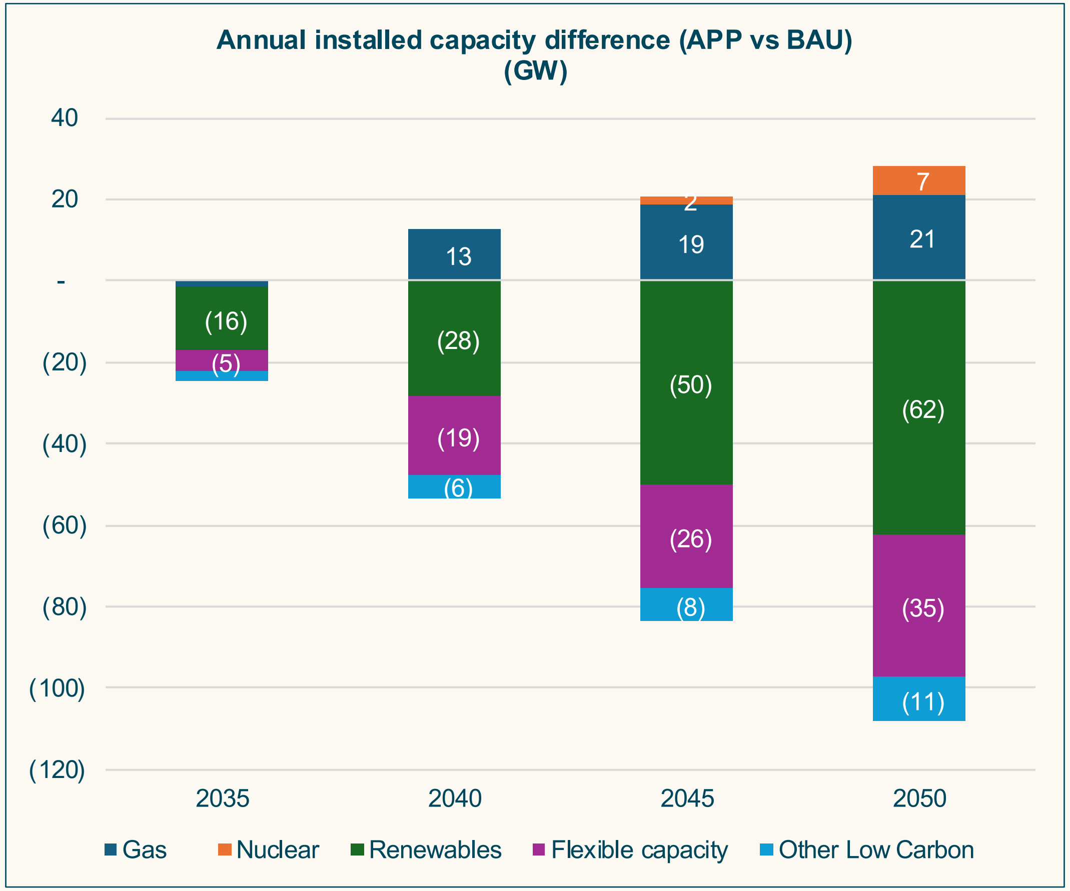
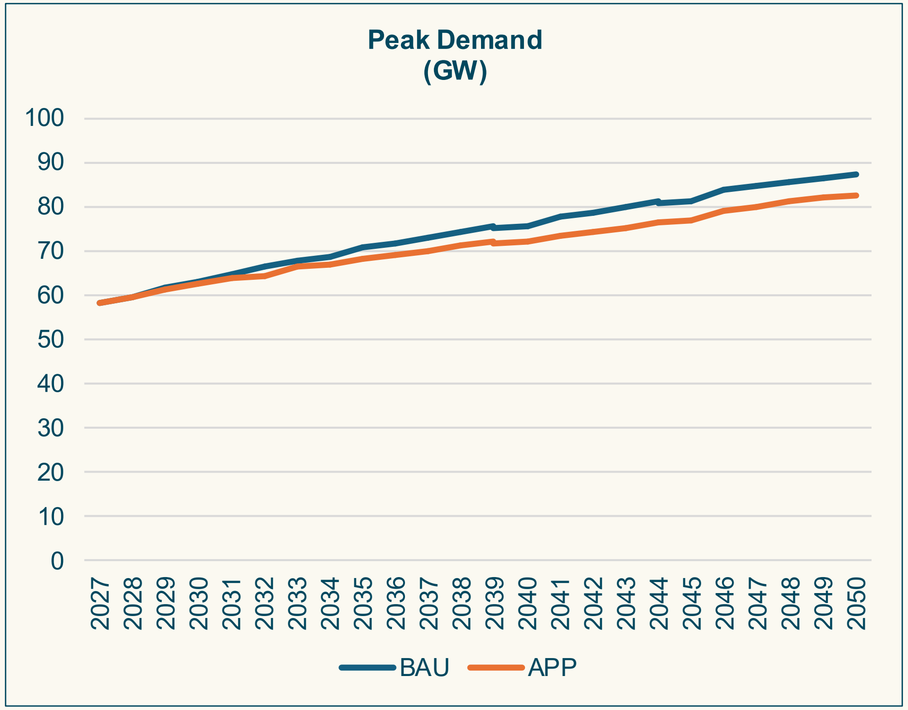


- Both a higher share of gas-fired capacity and growing power demand drive higher carbon emissions in APP compared to declining emissions in BAU.
- In BAU, the large expansion of renewable wind and solar generation, alongside complementary storage, and low carbon generation (including negative emissions BECCS) causes only minimal carbon emissions by 2050.

Sources: Transira. 1) All figures have been rounded to the nearest whole number. 2) Emissions impact excludes changes outside the GB power sector and relate to domestic generation only.

APP installs 80 GW less capacity than BAU by 2050 but only sees a 4.5GW reduction in peak demand

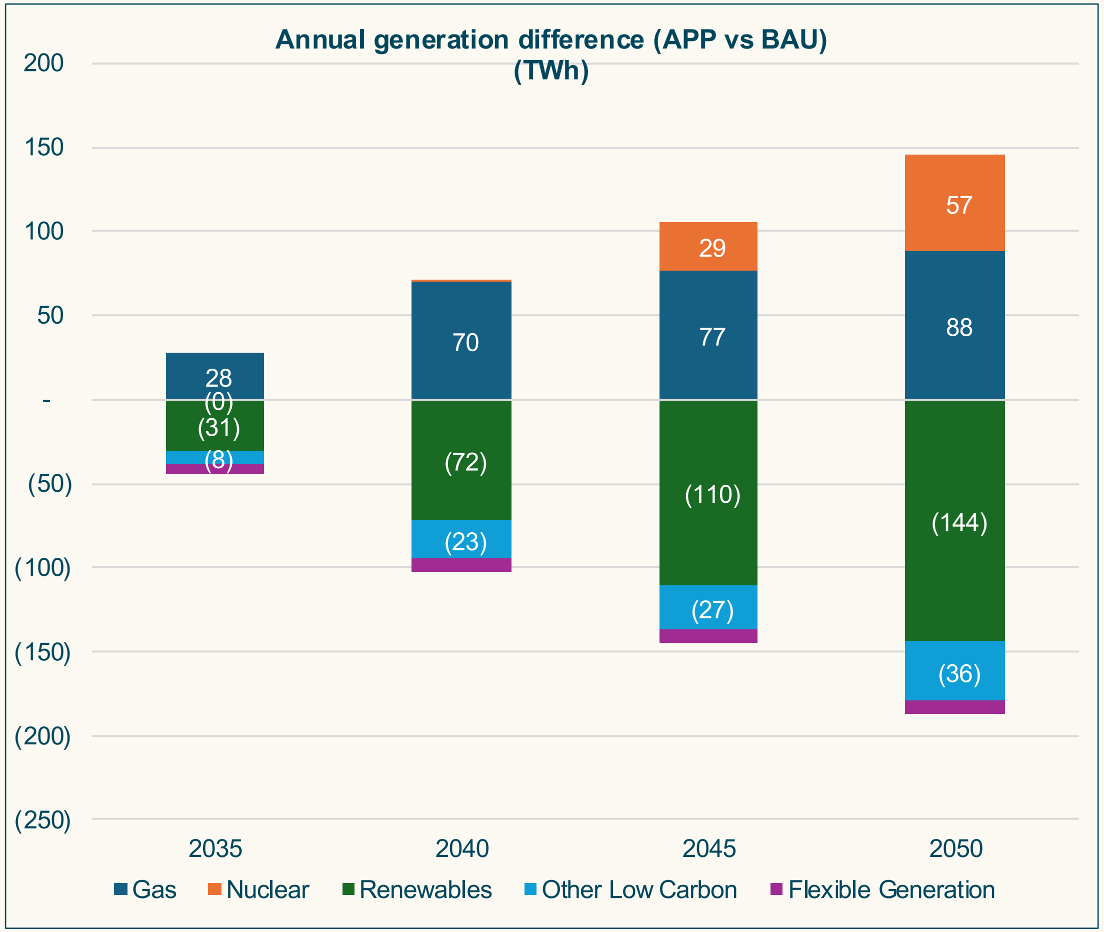




- By 2050, APP has ~80 GW less installed than BAU despite only a ~4.5 GW difference in peak demand. This is explained by the low utilisation of wind, solar, and flexible technologies. The reduction in installed capacity enables material savings on network expansion.

Source: Transira. 1) Renewables includes wind, solar, and other renewables. Low carbon includes BECCS, Hydrogen CCGT, and Gas CCS. Flexible generation includes BESS, pumped storage, interconnectors, and DSR.

APP generation moves towards nuclear and gas, vs BAU where gas is displaced by wind, solar and nuclear



- APP sees a significant reduction in renewables, comprising of wind and solar generation, alongside other low carbon technologies which include hydrogen and carbon capture technologies.
- Flexible generation sees a net decrease as efficiency losses from energy storage are removed.
- By 2050, total electricity supplied in APP is 43 TWh lower than BAU, consistent with lower electricity demand.

Source: Transira. 1) Renewables includes wind, solar, and other renewables. Low carbon includes BECCS, Hydrogen CCGT, and Gas CCS. Flexible generation includes BESS, Interconnectors, storage, and DSR.

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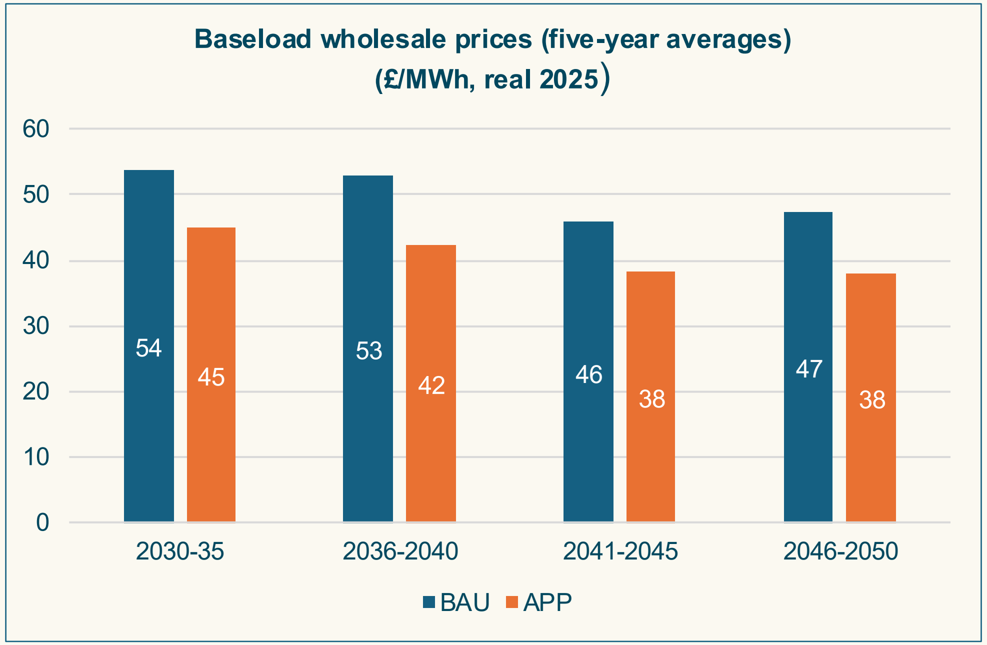
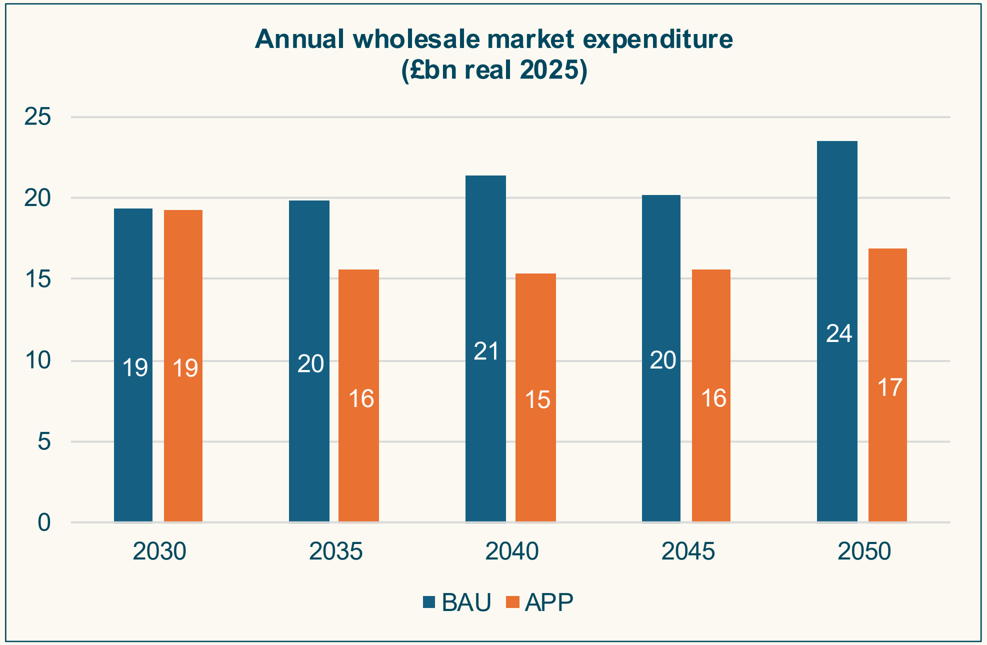
Wholesale prices and expenditure are lower in APP following removal of the UK ETS



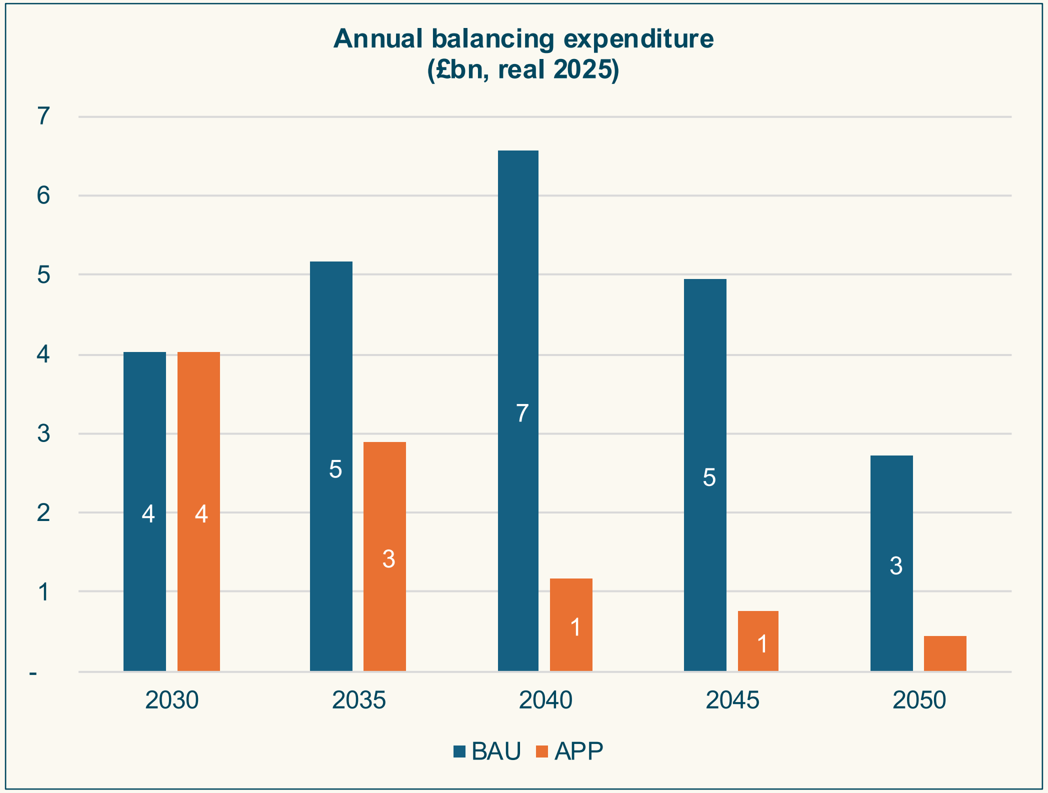


- Until 2030, wholesale prices are similar in BAU and APP. From 2031, prices in the two scenarios diverge more materially driven by the removal of the UK ETS in the APP scenario and the decreasing LCOEs of wind and solar generation in BAU.
- APP prices are 18% lower than BAU over 2030 – 2050.

- From the late 2030s, wholesale market costs in the two scenarios diverge, driven by the difference in wholesale prices and reflecting the higher generation base in BAU.
- The delta in cost peaks in 2050, driven by a combination of the higher wholesale price and higher electricity consumption.

Source: Transira. 1) All figures are rounded to the nearest whole number. 2) Five-year average baseload prices reflect the mean average of annual baseload prices for each five-year period.

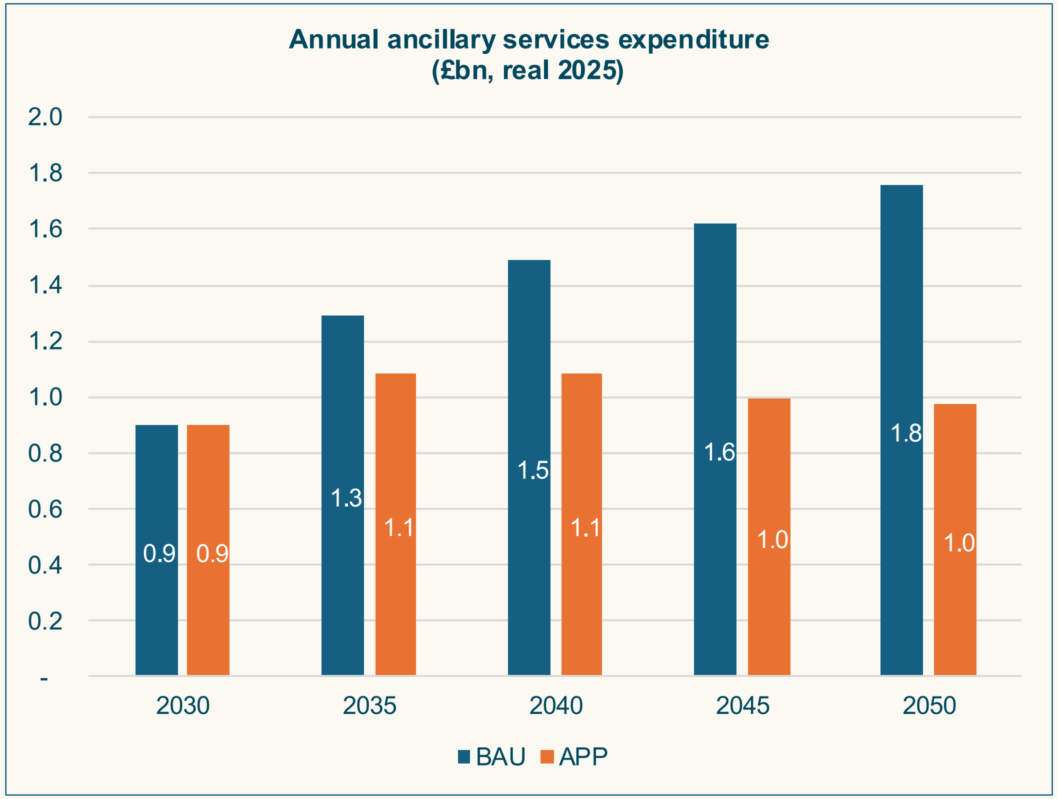
Balancing costs grow aggressively to 2040 in BAU, primarily driven by thermal constraints from wind deployment



- Balancing costs include energy balancing actions and thermal constraint actions taken by NESO to ensure that supply and demand are in equilibrium in real time. The costs related to ancillary services are considered in a separate category in the next slide.
- Balancing costs increase materially in BAU as the generation mix is dominated by intermittent generation that drives greater forecast error, which increases balancing volumes and expenditure.
- Transmission constraints between renewable-high regions (e.g. in Scotland) and demand centres (e.g. in the south of England) increase redispatch costs to solve thermal constraints. The majority of total balancing costs are driven by thermal constraints which consist of both redispatch costs and negative price bidding, which continue to rise as the network becomes increasingly congested, and then gradually fall after 2040 in both scenarios.
- APP sees a material saving in managing thermal constraints, as the share of wind generation declines from 2030.

Source : Transira, 1) Balancing costs above include both spending on actions taken to resolve thermal constraints and energy balancing actions. 2) BAU balancing cost levels in 2030 are lower than projected NESO balancing costs as reported in 2025 annual balancing costs report. 3) All figures are rounded to the nearest whole number.

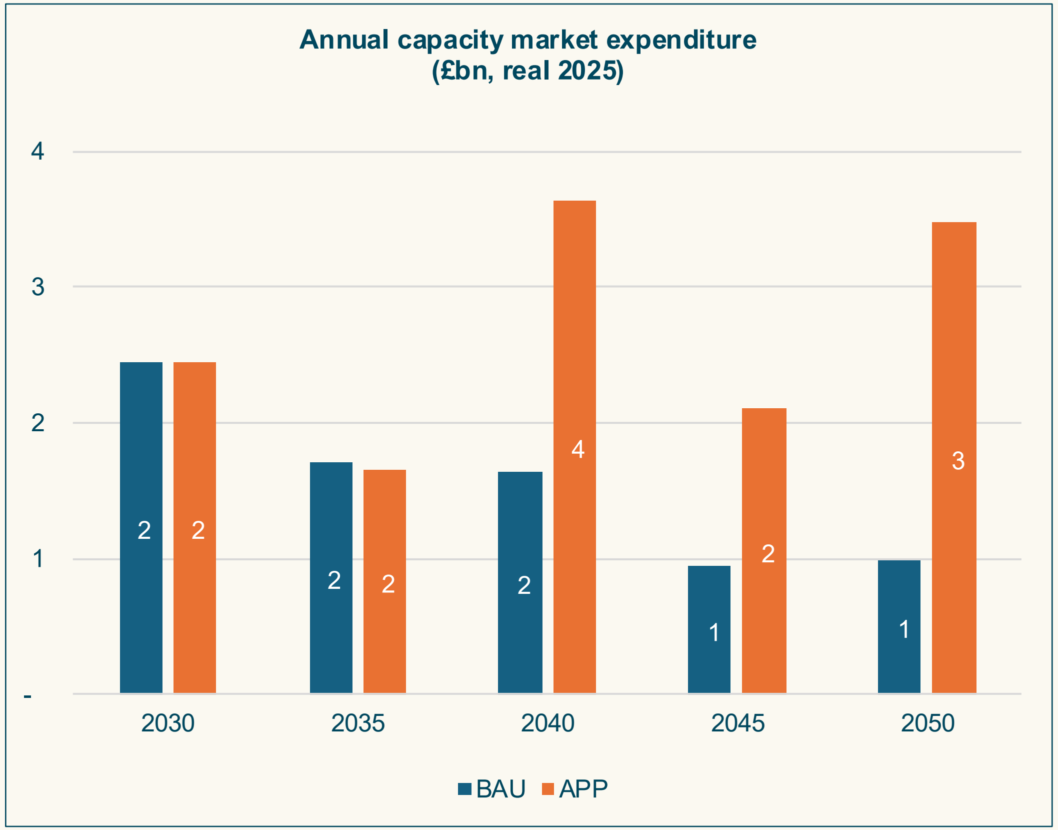
Ancillary services costs grow in BAU, driven by system operability needs to manage a high intermittent system



- The costs that relate to ancillary services include a range of services used to balance power supply and demand, as well as maintain system voltage, inertia, and frequency levels at 50Hz.
- Ancillary services costs are higher in BAU due to the growing share of non-synchronous and intermittent generation from wind and solar technologies. As the total share of wind and solar generation grows, NESO must procure additional volumes of ancillary services to maintain system operability that drives additional expenditure.
- In APP, ancillary service costs are lower than BAU due to its higher share of gas and nuclear generation. High levels of controllable and synchronous generation reduce the required volumes for reserve, response volumes, and voltage management which reduces overall expenditure.

Sources: Transira. 1) Costs above include spending on reserve, response, voltage and other minor components.

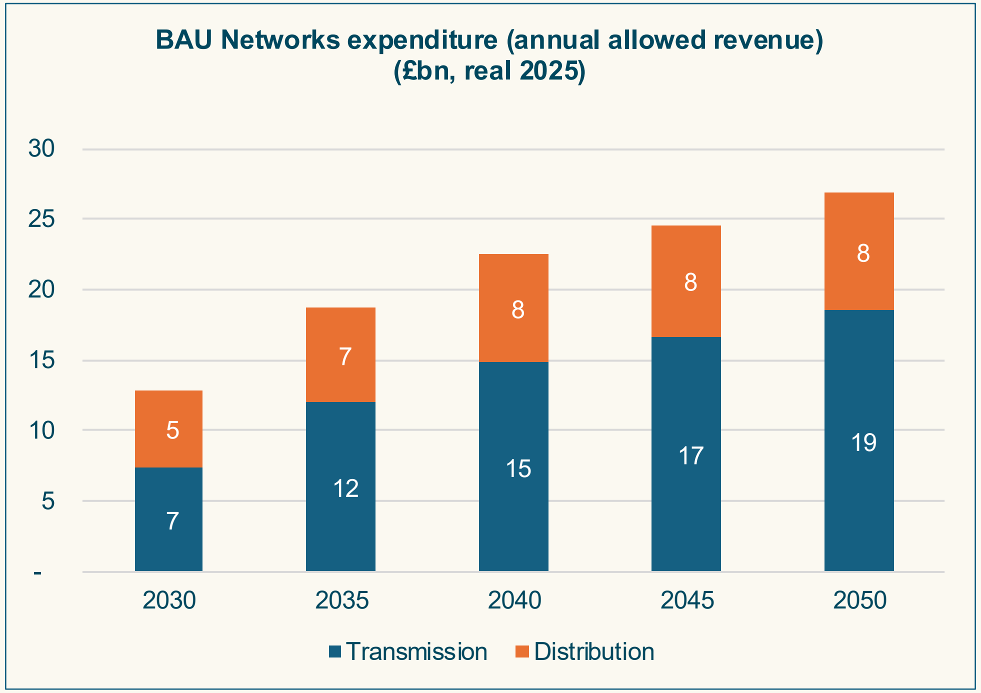
Cumulative APP Capacity market costs are £21 bn higher driven by increased procurement of gas-fired capacity

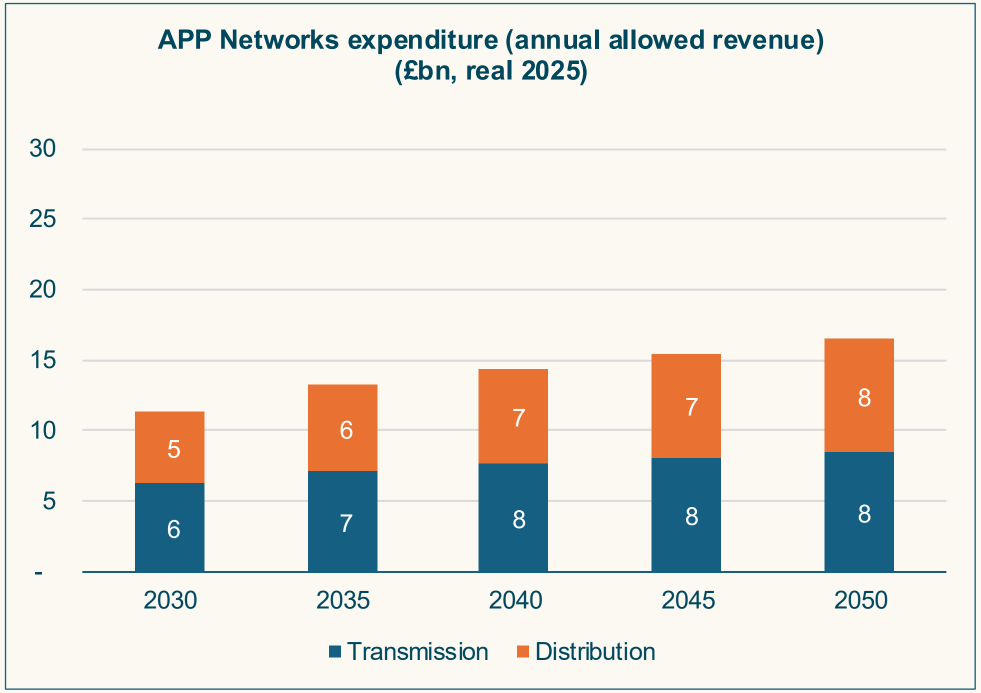


- Capacity market expenditure has been forecast based on auctions taken to date and future auctions in BAU and APP.
- Total capacity market expenditure is higher in APP as it increases the amount of capacity procured through auctions, namely, unabated gas.
- In contrast, BAU reduces the amount of capacity procured through auctions and procures firm capacity through alternative subsidy mechanisms for LDES, CCUS, hydrogen, and BECCS.

Source: Transira. 1) All figures are rounded to the nearest whole number. 2) Modelled capacity market auction clearing prices are set by NPV of new-build or existing plant pre-tax cashflow. Technical parameters for a new-build CCGT are based on an H-class CCGT, capex £650/kW (real 2025), fixed opex £25/kW/yr (real 2025), variable O&M is £5.00/MWh (real 2025). WACC assumed is 8.00% (real) under a 20-year CM contract in APP and 15-year contract under BAU.

BAU costs £10 bn more in network expenditure than in APP in 2050



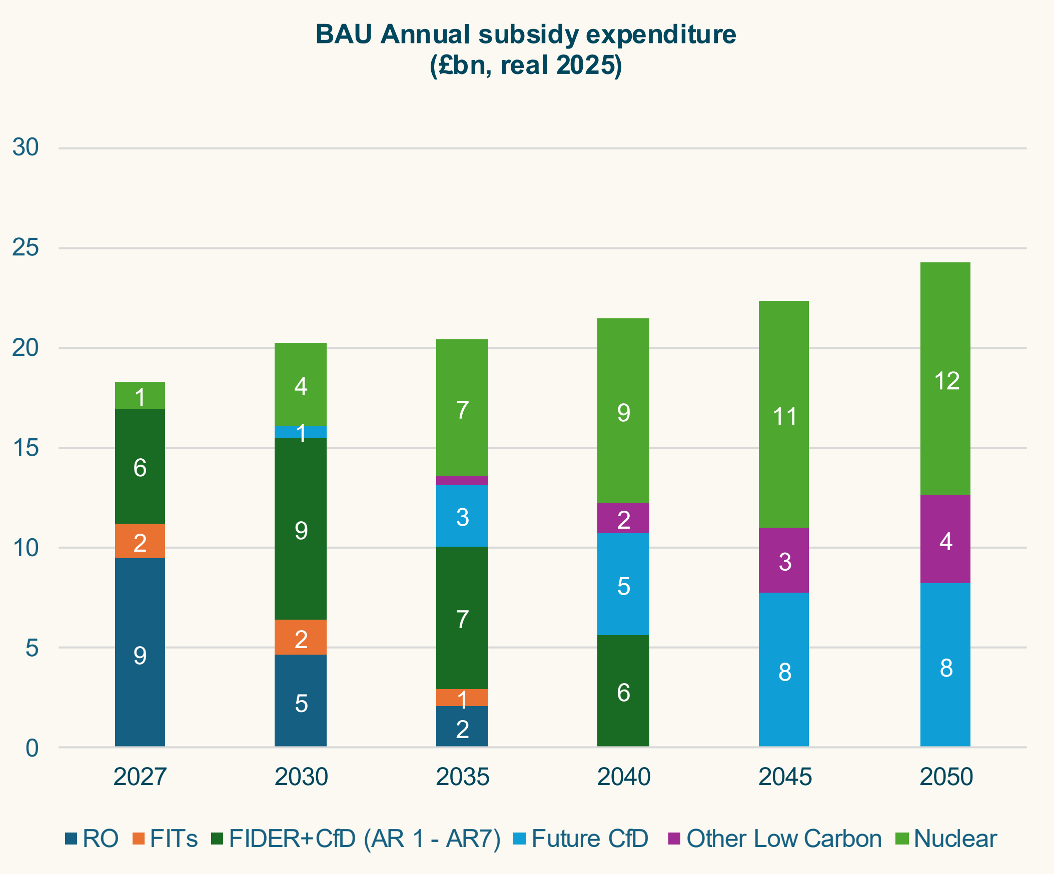


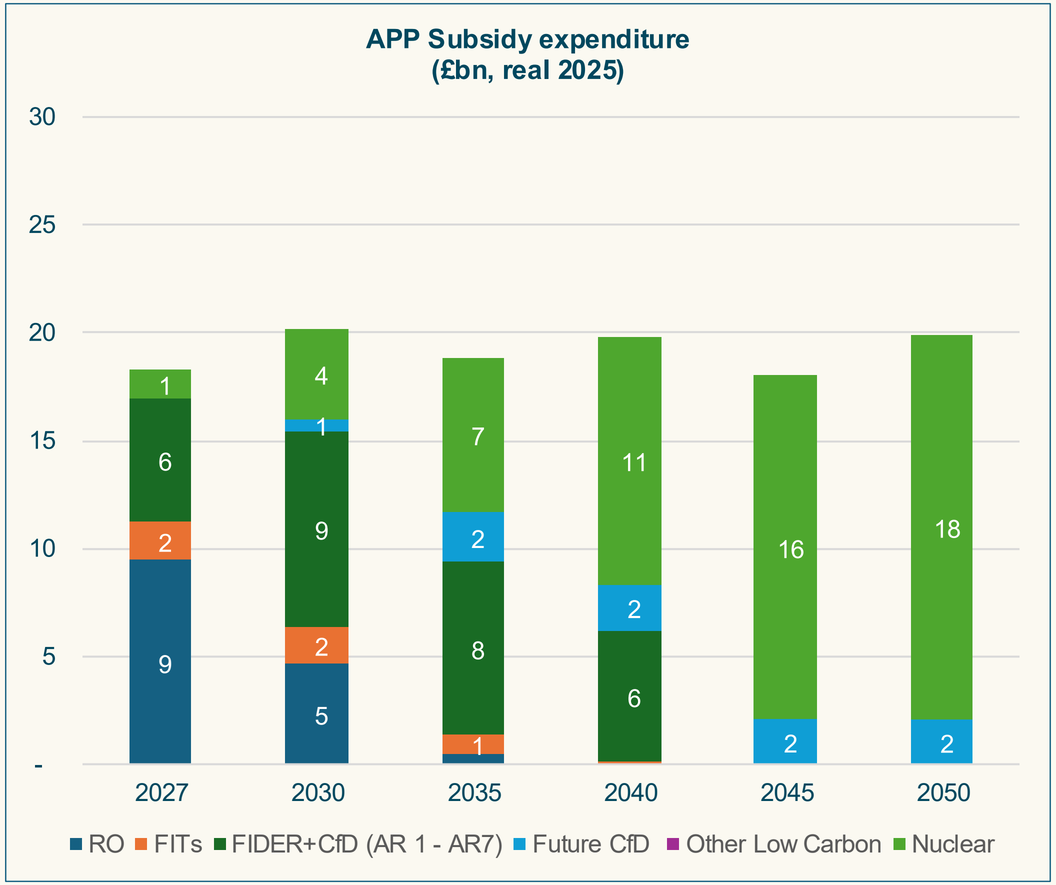
- Transmission spend grows steadily, driven initially by the need for new network build in the 2030s.
- Distribution spend increases at the end of RIIO ED2 and is maintained over the mid 2030s to meet domestic electrification demand and distributed solar connections.
- £137 bn of transmission network assets added to the RAV over 2030-2050 in BAU.

- Transmission spend reflects the cost to maintain the existing network and ensure that new gas and nuclear generation can connect in the APP. It grows more slowly compared to BAU, given the reduced requirement to connect offshore wind in particular. £19 bn of transmission network assets added to the RAV 2030-2050 in APP
- Distribution spend falls gradually from 2030 in APP to focus on meeting a lower level of network reinforcement. From the late 2030s it maintains relatively steady levels to focus on maintaining network health as DNOs have sufficient head room built into the network during ED2.

Sources: Transira, Ofgem RIIO ED2, T2 and T3 Price Control Data. 1) RAV is the Regulatory Asset Value. 2) All figures are rounded to the nearest whole number. 3) Network assets have an assumed life of 45 years. Opening transmission RAV (2026) is £38.25 billion for transmission and £37.98 billion for distribution. We assume a return on RAV of 4.5% and a capitalisation rate of 85% for transmission, and a return on RAV of 3.9% and a capitalisation rate of 70% for distribution. Straight-line depreciation is used for all new assets, including the initial RAV, over the assumed asset life.

Pre-existing CfD payments continue in APP, and all further support is exclusively on nuclear from 2030





- Overall subsidy expansion grows in BAU as it continues to fund intermittent RES, nuclear, LDES, BECCS, hydrogen and gas CCS technologies.

- APP sees the removal of RO payments for wind and solar from 2033, and all further subsidy growth from 2030 is exclusively on nuclear.
- Future CfD payments in APP represent CfD contracts awarded prior to 2030.

Sources: Ofgem, LCCC, Transira. 1) Low carbon includes BECCS, Hydrogen-fuelled generation, and Gas CCS. 2) All figures are rounded to the nearest whole number.

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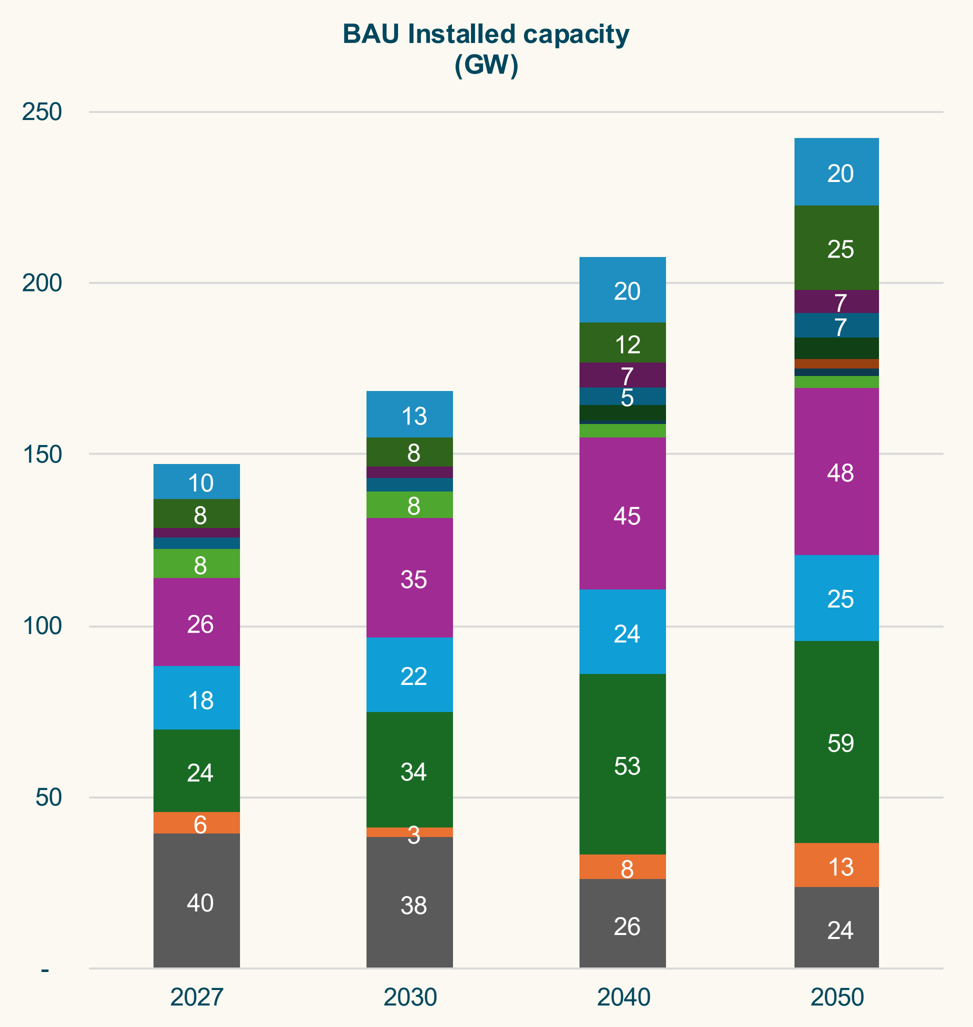
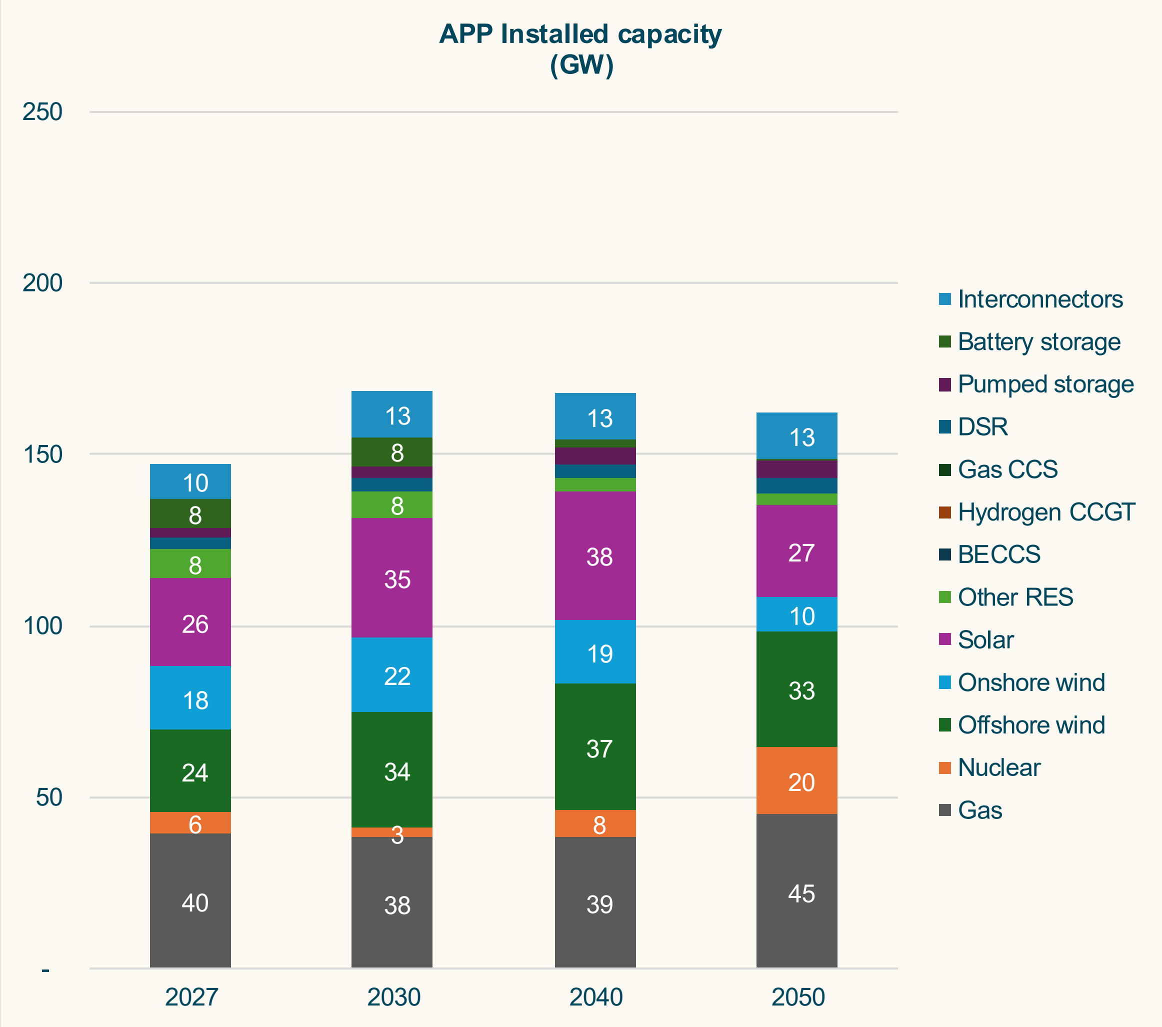
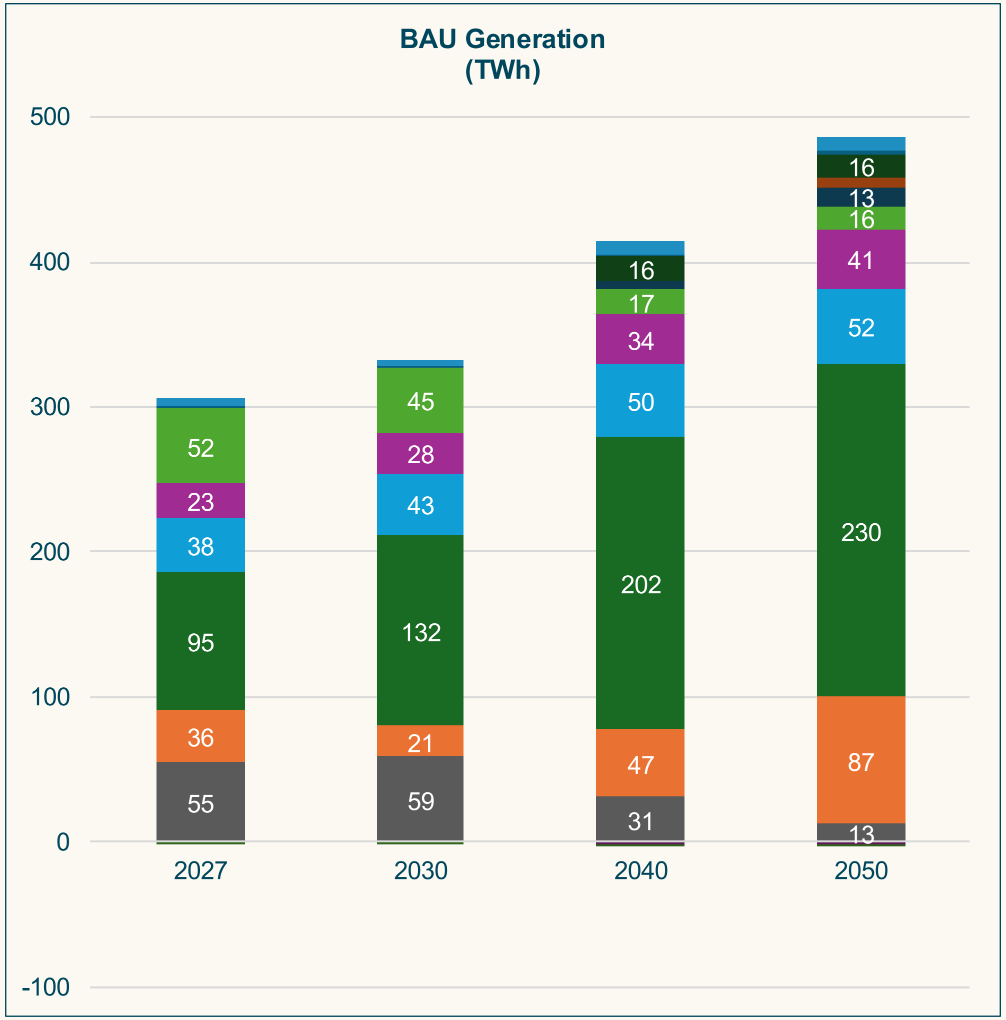
APP capacity is 80 GW lower by 2050 due to a higher share of firm capacity from gas and nuclear

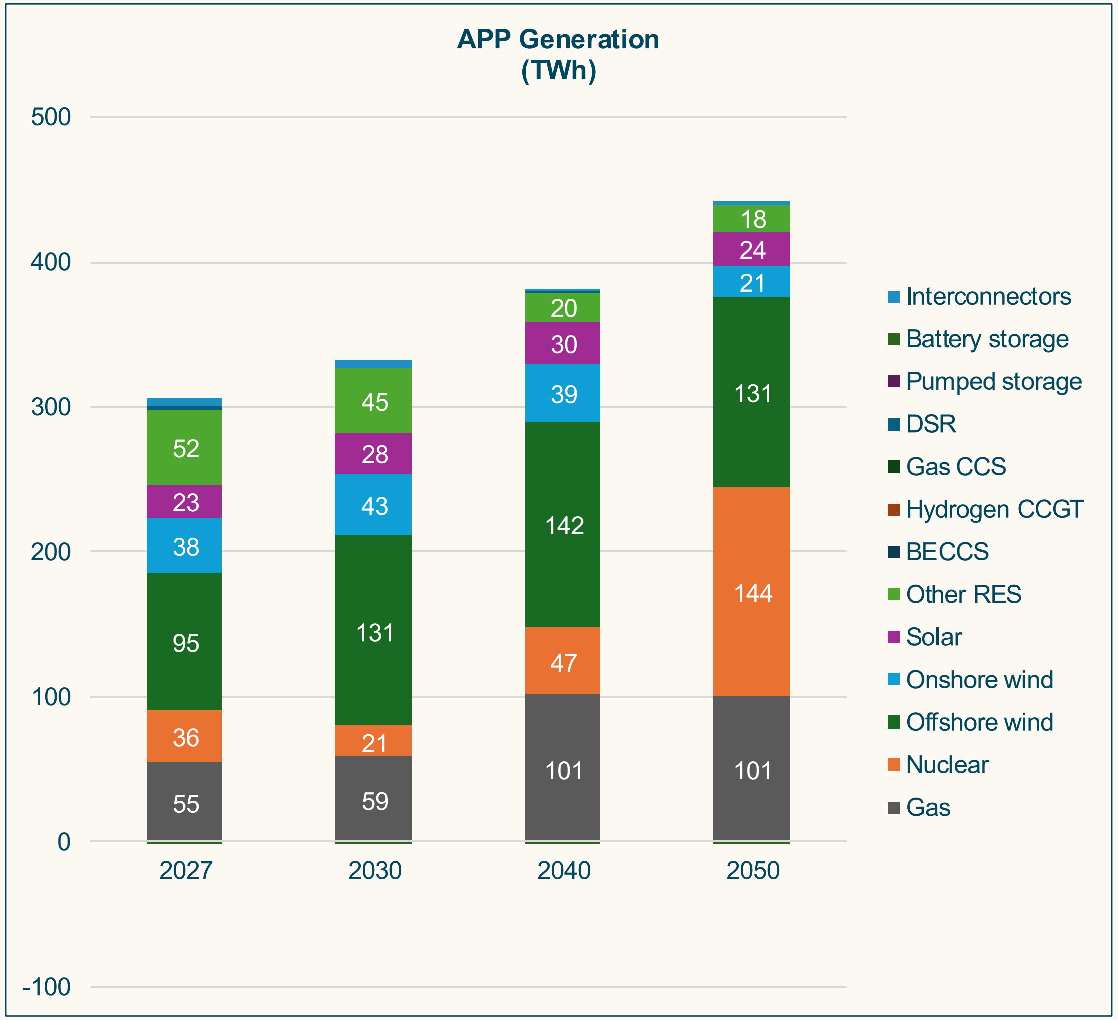




Source: Transira.

APP's generation moves towards nuclear and gas, while BAU materially increases RES generation





Source: Transira.

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Emissions

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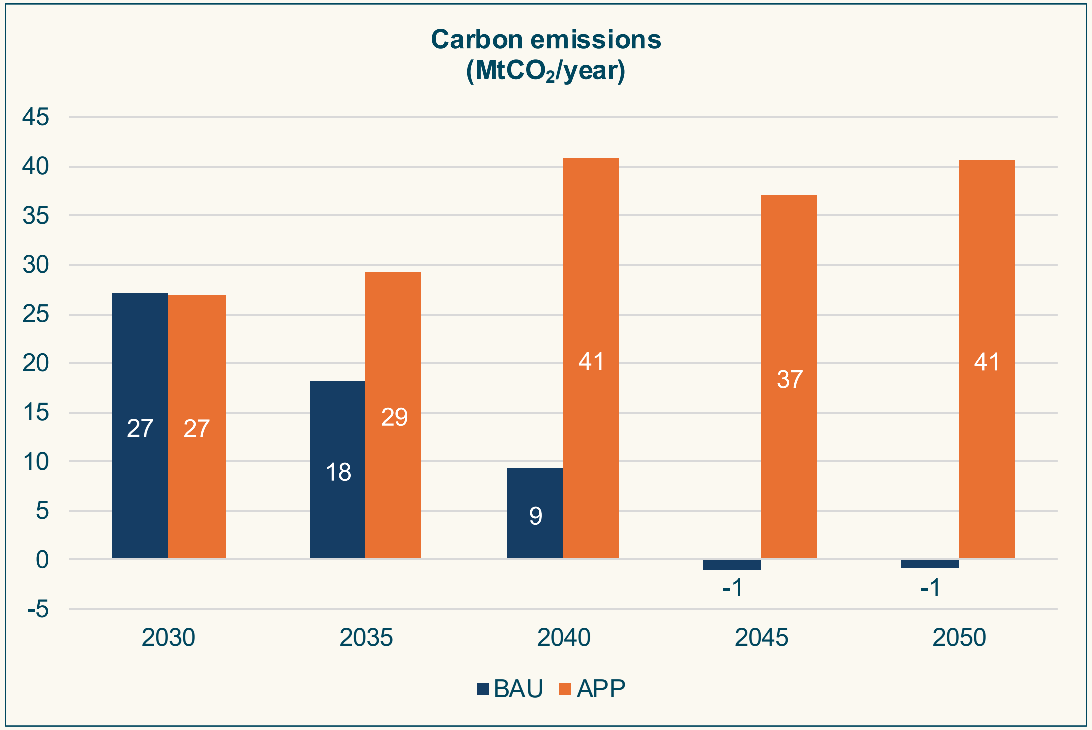

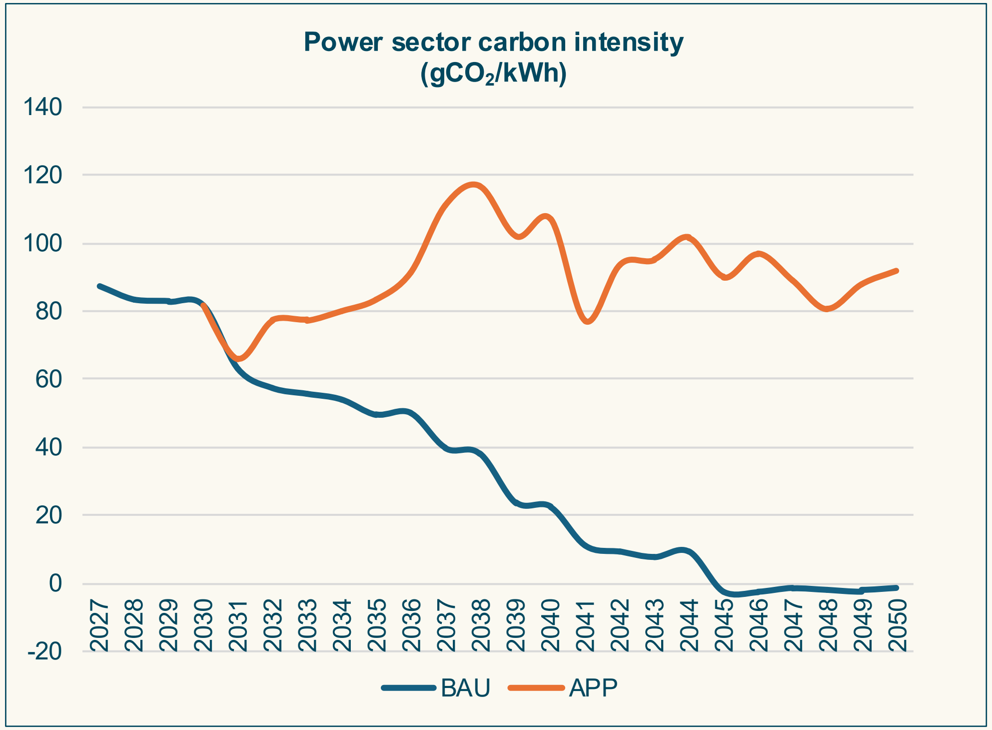

- Total emissions in the two scenarios start to diverge from 2030, in line with the increasing proportion of unabated gas generation in the APP scenario and the increasing proportion of low-carbon generation in the BAU scenario.
- Negative emissions in BAU scenario are driven by BECCS which are assumed to remove -600gCO_2/kWh.

- Carbon emissions intensity peaks in APP in 2038, driven by an increasing amount of gas generation in the mix. The fluctuations are driven by retirements of pre-existing renewables that are not replaced, and staggered growth of new gas and nuclear capacity.
- In contrast, BAU emissions intensity decreases rapidly in the 2030s following the increasing amount of wind and solar generation and becomes negative from 2045.

Source: Transira. 1) All figures are rounded to the nearest whole number. 2) Emissions impact excludes changes outside the GB power sector and relate to domestic generation only.

Modelling notes

- All results are scenario specific estimates rather than forecasts. They are sensitive to assumptions on policy implementation, fuel and carbon prices, technology costs, demand, weather, network delivery, asset lifetimes and financing conditions.
- The analysis covers GB power-system costs and direct operational CO_2 emissions only. It does not quantify effects in heat, transport, industry or the wider economy, and does not forecast household electricity bills, investor returns or economy-wide emissions.
- Network losses are not explicitly modelled. Their impact on system costs may be positive or negative, depending on the scale and geographical distribution of generation and demand, and the resulting network configuration.
- Natural gas and carbon prices are inherently uncertain. Changes in commodity prices can affect wholesale electricity costs in both scenarios presented.
- Future capital costs for technologies such as batteries, electrolysers, SMRs, large nuclear and carbon capture remain uncertain and may alter system costs.

Contents

Detailed subsidy expenditure assumptions (1 / 2)

TRANSIRA ENERGY

Parameter	Value / year of entry	Capacity factor	Sources
LCOE – fixed-bottom / floating offshore wind weighted avg. (£/MWh, real 2025)	£115 (2030) £106 (2035) £99 (2040) £95 (2045) £93 (2050)	40%	DESNZ (LCOE estimates Annex A)
LCOE - onshore wind (£/MWh, real 2025)	£60 (2030) £59 (2035) £57 (2040) £56 (2045) £55 (2050)	25%	DESNZ (LCOE estimates Annex A)
LCOE - solar PV (£/MWh, real 2025)	£62 (2030) £57 (2035) £54 (2040) £53 (2045) £51 (2050)	11%	DESNZ (LCOE estimates Annex A)
LCOE - biomass (Dedicated) (£/MWh, real 2025)	£124 (2030)	60%	DESNZ (LCOE estimates Annex A)
Strike price - nuclear (Hinkley Point C) (£/MWh, real 2025)	£138 (2030)	Not used for subsidy calculation	Transira, DESNZ
Strike price - nuclear (Sizewell C) (£/MWh, real 2025)	£150 (2039)	Not used for subsidy calculation	Transira, DESNZ
LCOE - nuclear - SMR (£/MWh, real 2025)	£138 (2039) £108 (2045)	Not used for subsidy calculation	Transira
LCOE - nuclear - New large-scale (£/MWh, real 2025)	£138 (2041) £122 (2048)	Not used for subsidy calculation	Transira

1) Where stated, Transira uses both LCOEs and capacity factors quoted by DESNZ to calculate required revenues for subsidy expenditure. Capacity factors in generation results are driven by PLEXOS dispatch for all technologies. All subsidy expenditure assumes wholesale revenues at the prevailing capture price for each technology and is deducted from required revenues. 2) Allowed revenue during construction for nuclear has been included for nuclear based on Capex ranging from £10,000/kW to £12,500/kW . 3) Offshore wind LCOEs reflect an 85% fixed-bottom and 15% floating weighted average.

TRANSIRA ENERGY

Detailed subsidy expenditure assumptions (2 / 2)

Parameter	Value / year of entry	Capacity factor	Source
Pumped Hydro (£/MWh, real 2025)	£183 (2030)	15%	DESNZ (LCOE estimates Annex A)
Hydrogen turbine (£/MWh, real 2025)	£333 (2046)	30%	DESNZ, (LCOE estimates Annex A), IEA, ESI
Gas CCS (£/MWh, real 2025)	£188 (2032)	30%	DESNZ (LCOE estimates Annex A), IEAGHG, IEEFA
BECCS (£/MWh, real 2025)	£250 (2037)	50%	IEA, Ember, IEAGHG

1) Where stated, Transira uses both LCOEs and capacity factors quoted by DESNZ to calculate required revenues for subsidy calculations. Capacity factors in generation results are driven by PLEXOS dispatch for all technologies. All subsidy expenditure assumes wholesale revenues at the prevailing capture price for each technology and is deducted from required revenues. 2) Other types of emerging generation technologies and smaller generation technologies that are not seeing any new build in the BAU and APP are not included within this assumption table. This includes landfill and sewage gas, geothermal (deep granite), tidal stream energy, and run of river hydro.

Existing and pipeline nuclear assumptions

Nuclear station name	Capacity (MW)	Retirement / Commission Date	Notes
Hartlepool	1,200	April 2028 (Retiring)	Retiring
Heysham 1	1,185	April 2028 (Retiring)	Retiring
Heysham 2	1,200	April 2030 (Retiring)	Retiring
Sizewell B	1,260	2055 (Retiring)	Assumes 20-year life extension
Torness	1,200	April 2030 (Retiring)	Retiring
Hinkley Point C	3,200	2030 (COD)	Under construction
Sizewell C	3,200	2039 (COD)	Under construction

Sources: EDF Energy, The Guardian. 1) COD = Commercial operation date

Emission intensity per generating technology class

Technology	Carbon intensity (gCO_2/kWh)
Biomass	120
Waste	600
Wind, solar, and other technologies with zero direct operational emissions	0
Nuclear	0
Hydrogen blend fuelled turbine	175
Unabated gas-fired technologies	Based on efficiency at plant level (0.202 tonnes/MWh fuel intensity)
Gas CCGT (CCS)	50
BECCS	-600

Sources: Transira, NESO, IEA, IPCC. 1) Efficiencies for gas fired technologies are defined at asset level based on proprietary data from Energy Exemplar and research by Transira. 2) All emissions stated exclude full lifecycle emissions.

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