Distribution Future Energy Scenarios 2021

South West licence area

Results and assumptions report

regen transforming energy

WESTERN POWER DISTRIBUTION
Serving the Midlands, South West and Wales

This report was produced for	Western Power Distribution
Issue date	06 January 2022
Version	Final
Analysis and report by:	Jonty Haynes and Grace Millman
Approved by:	 Ray Arrell, project director

Regen, Bradninch Court, Castle St, Exeter EX4 3PL

Regen is a trading name of the company Regen SW registered number: 04554636

Table of Contents

Glossary

Acronym	Definition
ACT	Advanced Conversion Technologies
AD	Anaerobic Digestion
ASHP	Air Source Heat Pump
BECCS	Bioenergy with Carbon Capture and Storage
BEIS	Department for Business, Energy and Industrial Strategy
BEV	Battery Electric Vehicles
CCGT	Combined-Cycle Gas Turbine
CCUS	Carbon Capture and Storage
CHP	Combined Heat and Power
DFES	Distribution Future Energy Scenarios
DNO	Distribution Network Operator
EMR	Electricity Market Reform
ENA	Energy Networks Association
EPC	Energy Performance Certificate
ESA	Electricity Supply Area
ESO	Energy System Operator
EV	Electric Vehicle
FES	National Grid ESO Future Energy Scenarios
FHS	Future Homes Standard
GHG	Green House Gases
GIS	Geographic information system
GSHP	Ground Source Heat Pump
GSP	Grid Supply Point
GW	Gigawatt
HGV	Heavy Goods Vehicle
HNDU	Heat Network Delivery Unit
HNIP	Heat Network Investment Project
kW	Kilowatt
LA	Local Authority
LCT	Low Carbon Technology
LGV	Light Goods Vehicle
LPG	Liquefied petroleum gas
LV	Low Voltage
MW	Megawatt
OCGT	Open-Cycle Gas Turbine
PHEV	Plug-in Hybrid Electric Vehicle
PV	Solar Photovoltaics
REPD	Renewable Energy Planning Database
RHI	Renewable Heat Incentive
SCR	Significant Code Review
SMR	Steam Methane Reformation
UKCS	UK Continental Shelf

Introduction to the WPD DFES 2021

Background:

The WPD DFES provides granular scenario projections for generation, demand and storage technologies that are or will be connected to the electricity distribution network, out to 2050. The analysis also includes projections for new housing, commercial and industrial developments, which represent sources of new electricity demand. The projections are directly informed by stakeholder engagement, to reflect local and regional drivers, the needs and plans of local authorities, and views of other sector stakeholders, such as project developers, technology companies and community groups.

For the DNOs, the DFES allows network planners to model and analyse different future load scenarios for their network. This data then informs integrated network planning and investment appraisal processes. The DFES also provides a key data resource and evidence base to enable WPD to appraise different investment options and develop the business case necessary to support future investment, including regulated business plans.

Figure 1 – The WPD DFES annual process

The scope:

The WPD DFES 2021 scope encompasses all technologies that directly connect to or interact with the distribution network in the four WPD licence areas: South Wales, South West, East Midlands, and West Midlands. By definition, this excludes large-scale assets connecting directly to the National Grid transmission network, such as nuclear power, most offshore wind, and many gas-fired power stations.

The DFES analyses technology types which are of a similar scope to the National Grid FES 2021. These are standardised against "building blocks" as reported in the FES 2021, developed by the ENA Open Networks project.

The analysis considers both existing connections and the pipeline of future potential projects aiming to be deployed within WPD's licence areas. This report focusses on those projects within the South West licence area.

The scenarios used for projection purposes extend from 2021 to 2050 and are aligned to the four FES 2021 scenarios: **Consumer Transformation**, **Leading the Way**, **Steady Progression**, and **System Transformation**. In this year's DFES analysis, several new technologies have been included for the first time. These include hydrogen electrolysis, hydrogen-fuelled power generation, and several types of electrified heating. The technology types and assumptions are under constant review and may change with future FES and DFES rounds in line with stakeholder feedback.

The results and assumptions:

The WPD DFES 2021 analysis is produced to granular geographic areas known as Electricity Supply Areas (ESAs), of which there are two types:

- Geographic ESA: the geographical area supplied by a Primary Substation (which contains WPD-owned distribution substations) providing supplies at a voltage below 33 kV,
- Single customer ESA: a customer directly supplied at 132, 66 or 33 kV or by a dedicated Primary Substation'.

These ESAs are also split by local authority boundaries, allowing the data to be aggregated to local authority or primary substation totals.

The DFES provides projections of capacity (MW) and numbers (i.e. number of EVs or heat pumps), but does not include analysis of network loads, load profiles or peak demand etc. This network load analysis is run by WPD network strategy and planning teams. WPD has published the results of this process on their website.

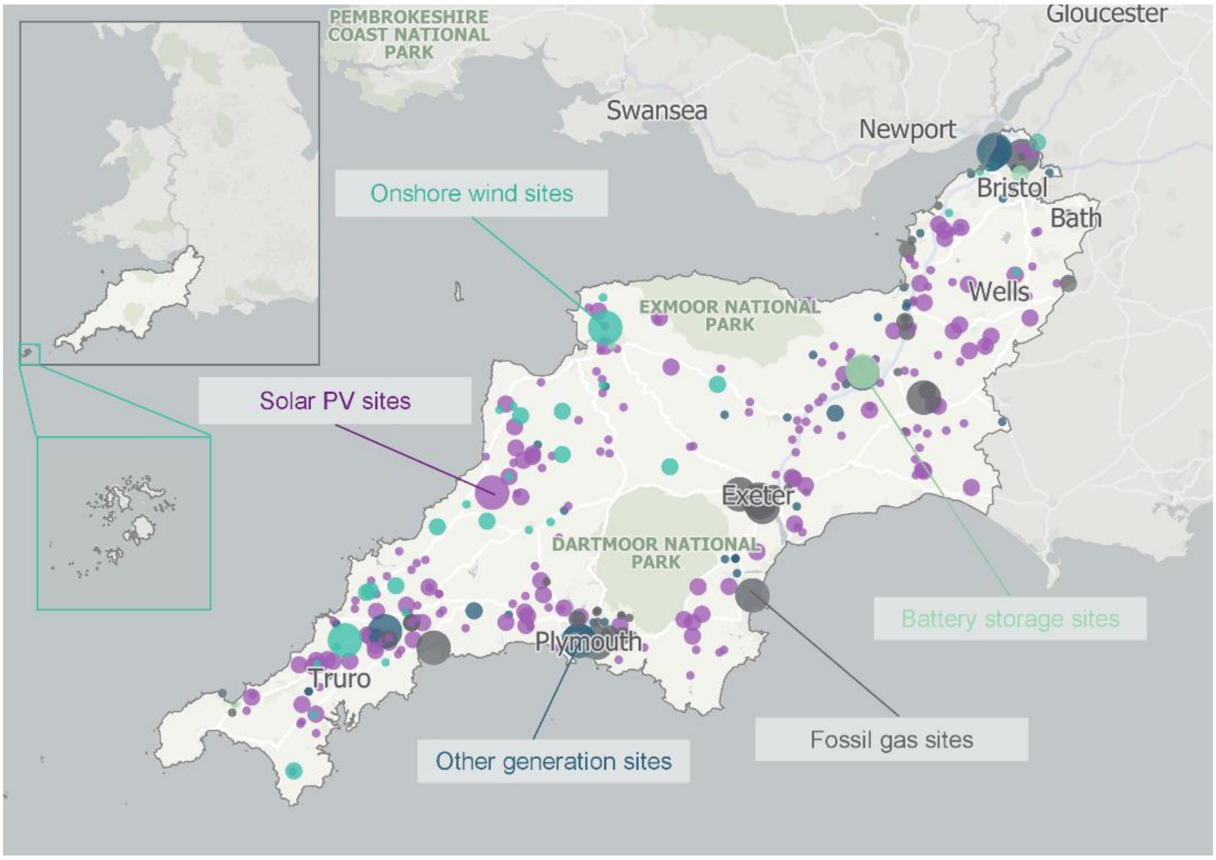
The South West licence area

The WPD South West licence area contains a mixture of more populated areas, including Bristol, Exeter and Plymouth, alongside more sparsely populated rural areas, two national parks and hundreds of miles of coastline.

While there is historical electricity generation in the area, including hydropower sites on Dartmoor and some of the first onshore wind farms in the UK, distributed electricity generation in the area has increased significantly in recent years. Over 50% of generation capacity connected to the distribution network has connected since 2014. The South West licence area has some of the highest levels of solar irradiance in the UK, and several areas of significant wind resource along the north coast of Devon and Cornwall.

In terms of electricity demand, domestic demand has steadily fallen over the last ten years as a result of increasing energy efficiency. However, new low carbon technologies such as electric vehicles and heat pumps are anticipated to increase electricity demand from homes and businesses. While only around 1% of South West homes currently have a heat pump or have an electric vehicle. However, uptake of these technologies could rapidly increase over the coming decades, significantly altering the demand on the electricity distribution network in the region.

Figure 2 - The WPD South West licence area, with the location of large-scale generation and storage sites



Local stakeholder influences

The development of the DFES has enabled WPD to take a more proactive approach to network planning. Stakeholders have been consulted via a series of consultation events, as well as direct engagement with local authority planners, climate emergency officers, project developers, energy technology companies, asset owner/operators and community energy representatives.

The four consultation events, one per licence area, were held online in June 2021. This allowed high levels of attendance and participation across a wide range of local stakeholders, to directly communicate and seek views on the analysis for the various technologies in-scope at a licence-area-specific level. To watch a recording of the stakeholder engagement events, or to read the reports summarising how the feedback has been incorporated into the DFES, visit the WPD DFES website.

Methodology summary

The DFES methodology is summarised below. A more detailed methodology report is available on the WPD DFES website.

Baseline analysis

Existing generation and demand on the distribution network is analysed to produce a baseline for the future scenarios. The baseline year for this year's analysis is up to the end of March 2021. This is based on WPD connection data, supplemented with project and subsidy registers, Department for Transport data, planning data, EMR Delivery Body Capacity Market registers and other national datasets. This produces an accurate starting point for the future scenarios, alongside analysis of historical uptake and location for each technology.

Pipeline analysis

Once a baseline is established, projects that are currently in development are analysed, reflecting the likely changes to generation and demand in the near term. This includes sites that have accepted a connection offer from WPD but that have not yet connected, or sites that are otherwise active, such as applying for or securing planning permission. Where possible, a discussion is held with a developer or relevant organisation to inform the scenario projections for these projects.

Demand from new domestic and non-domestic property developments is also included in the analysis. Local authority planning departments are contacted to verify the information and to provide insight into the rate of development within their planning period (in most cases the next 10-15 years). This consultation with local authorities also identifies where there are plans or strategies for supporting renewable energy deployment, decarbonisation of heat and transport, net zero declarations and any other energy-related plans or ambitions. These local factors are then, where possible, reflected in the scenario analysis and spatial distribution.

Annual cycle

WPD DFES is published on an annual basis, allowing scenario projections to be regularly updated to reflect the most up-to-date information available. The DFES is produced over the summer and published in the autumn, a few months after the release of the National Grid ESO FES publication and data. This allows the DFES to integrate the high-level scenario framework and assumptions from the latest FES, undertake a technology-specific reconciliation at licence area level (where possible) and should allow the outcomes and findings of the DFES to feed into the following year's FES.

The WPD DFES uses the FES as a framework, adopting the same scenario naming convention, broad national societal, technological and economic assumptions. However the DFES is a bottom-up analysis of a changing energy system at a regional and sub-regional level that reflects specific regional and local factors. For most technologies, the national view presented by the FES is not directly reflected at a regional or local level. For example, an increase in onshore wind capacity at a national level will inevitably be reflected more in areas of significant onshore wind resource, such as South Wales, and less so in areas with limited resource, such as the West Midlands. The regular annual cycle allows for data sharing between the WPD DFES and the National Grid ESO FES teams, facilitating continuous improvement of the data quality and processes.

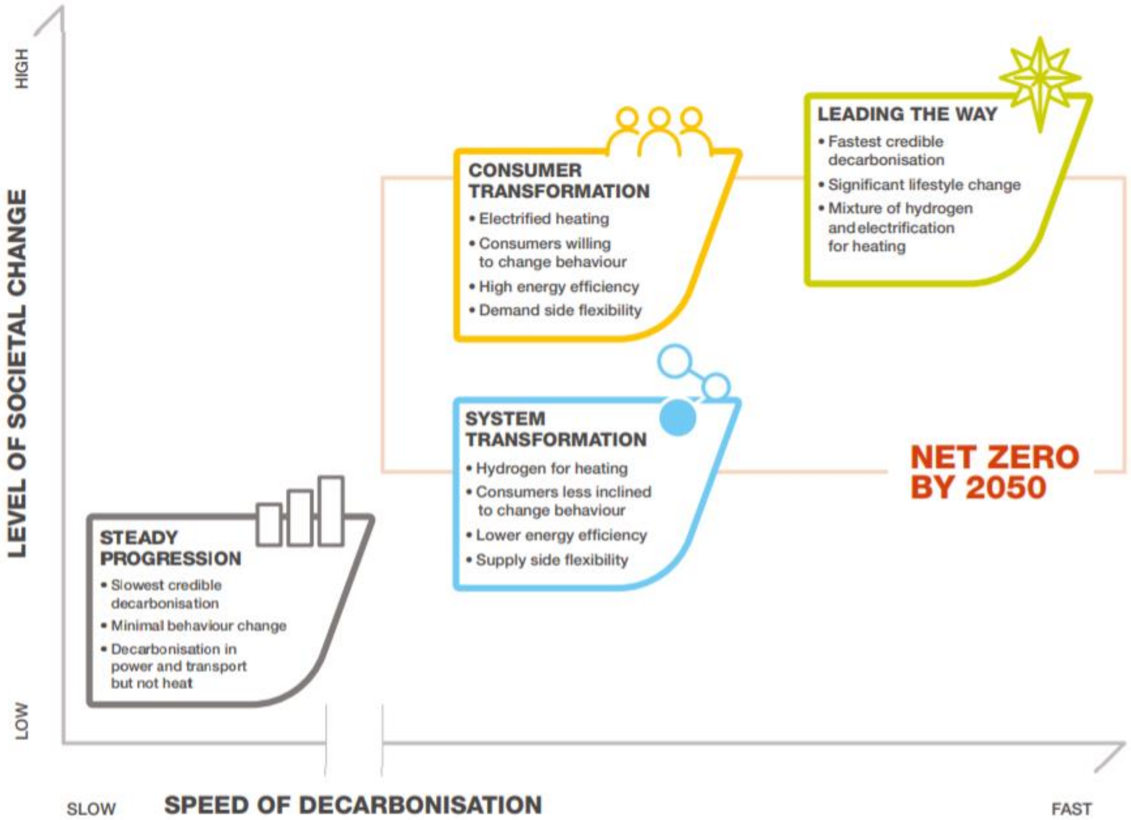
Scenario projections

The WPD DFES 2021 uses the same four future scenarios as the National Grid ESO FES 2021. These are the same scenarios as the 2020 iterations of the DFES and FES, but have been updated to reflect new information, data and policy drivers over the past year. The scenarios reflect various speeds of decarbonisation against levels of societal change, as illustrated in Figure 3.

Of these four scenarios, three (**Leading the Way**, **Consumer Transformation**, and **System Transformation**) meet the government target of net zero emissions by 2050. However, they achieve these emissions reductions in different ways and at different rates. The remaining **Steady Progression** scenario represents a failure to meet net zero carbon emissions by 2050.

Key assumptions from the FES 2021 scenarios have been included in the DFES analysis and are detailed throughout this report. Further assumptions made to inform the DFES projections, including technology costs, spatial factors, the fate of sites in the pipeline etc. are detailed in the technology specific sections of this report.

Figure 3 – The National Grid ESO FES 2021 scenario framework



Access and Forward-looking Charges Significant Code Review

Ofgem announced in summer 2021 some minded to decisions related to the Access SCR[1], in particular the intention to reduce the connection boundary for distribution connections. This means projects could have a lower cost to connect to the distribution network from April 2023. The consultation about these and other changes closed in August 2021, and a final decision is expected before the end of Q1 2022.

At the Charging Futures Forum in September 2021, Ofgem stated that they retain their view that the benefits of these changes will outweigh the increased cost to consumers. Therefore, within this final decision, there is anticipated to be a 'shallow' boundary for demand connections, removing all contribution to network reinforcement. For generation, a 'shallower' boundary for connections is also anticipated, essentially meaning a reduction in the contribution to reinforcement. It will likely consist of limiting the contribution to the required reinforcement based on the voltage level the generation asset is connecting at, and removing any contributions for reinforcement in the voltage level above. This is positive news for project developers, as it is often the 'one above' reinforcement that involves the highest costs.

However, Ofgem have stated that they are developing some 'mitigations' to protect consumers against any particularly high costs that these changes may trigger, which could dampen the benefits for project developers. The details of these mitigations are yet to be clarified.

It is likely that the impact of the changes to demand charging will be most significant for high electricity users, with a lower impact on domestic households, due to the latter being less likely to trigger reinforcement work.

The largest impact would be expected for high electricity demand technologies such as EV chargers. This could lead to a potential pause in connections of high voltage charging hubs, and a slower electrification of transport depots, before April 2023, followed by an equivalent short-term uptick after April 2023. The change will benefit existing industrial or business users looking to electrify demand, heat or processes. Hydrogen electrolysers would also likely benefit significantly from these changes, though significant deployment of electrolyser capacity is not anticipated until after these potential changes would be implemented.

From the generation side, the benefits are likely to be much more project specific, as it will depend on whether there are constraints and resultant reinforcement that will be triggered at the voltage level above that which the project is connecting at. Many generation projects will still be facing high costs for 'sole use assets' and reinforcement at their connection voltage. Given that costs rise with the voltage level, the potential changes would likely result in greater benefits for small LV generators and rooftop solar.

Battery storage connections, with both demand and generation capacity, could also be strongly influenced by the outcome of the SCR.

For the purposes of this DFES analysis, it has been assumed that the minded-to decision is implemented under **Consumer Transformation** and **Leading the Way**.

Retained capacity for decommissioning assets

Across the four DFES scenarios, some technologies will see a level of decommissioning between the baseline year and 2050. This largely consists of technologies that are incompatible with net zero carbon emissions, such as unabated fossil fuel power generation.

However, when an asset ceases conventional operation, the connection agreement held by the operator and the associated contracted export capacity secured with WPD is not automatically relinquished. It is likely that at least some sites will retain their connection capacity, with a view to participating in network ancillary services such as Short Term Operating Reserve, or for the potential future connection of an alternative generation or storage technology that is more compatible with net zero emission targets.

To address this, the DFES 2021 analysis has assumed that any connection capacity 'freed up' by the mothballing of a site, the removal of a generation asset or significantly reduced onsite operating hours, is either retained for ten years, or until a newly commissioned technology has been modelled to take its place, whichever comes sooner. This assumption is based on engagement with stakeholders, and internal network planning teams at WPD.

Example outcomes for decommissioning technologies include:

Decommissioned technology	Alternative technologies	Applied in which scenario
Diesel generation	Battery storage	All scenarios
	Hydrogen-fuelled generation	
	Retained capacity	
Fossil gas generation	Battery storage	Leading the Way
	Hydrogen-fuelled generation	Consumer Transformation
	Retained capacity	System Transformation

List of technology types analysed as part of the WPD DFES 2021:

DFES technology	DFES sub-technology	Equivalent Building block ID number
Biomass & Energy Crops (including CHP)	-	Gen_BB010
CCGTs (non CHP)	-	Gen_BB009
Geothermal	-	Gen_BB019
Hydro	-	Gen_BB018
Hydrogen-fuelled generation	-	Gen_BB023
Marine	Tidal stream	Gen_BB017
Marine	Wave energy	Gen_BB017
Non-renewable CHP	<1MW	Gen_BB001
Non-renewable CHP	>=1MW	Gen_BB002
Non-renewable Engines (non CHP)	Diesel	Gen_BB005
Non-renewable Engines (non CHP)	Gas	Gen_BB006
OCGTs (non CHP)	-	Gen_BB008

Other generation	-	-
Renewable Engines (Landfill Gas, Sewage Gas, Biogas)	-	Gen_BB004
Solar Generation	Commercial rooftop (10kW - 1MW)	Gen_BB012
Solar Generation	Domestic rooftop (<10kW)	Gen_BB013
Solar Generation	Ground mounted (>1MW)	Gen_BB012
Waste Incineration (including CHP)	-	Gen_BB011
Wind	Offshore Wind	Gen_BB014
Wind	Onshore Wind <1MW	Gen_BB016
Wind	Onshore Wind >=1MW	Gen_BB015
Storage	Co-location	Srg_BB001
Storage	Domestic Batteries (G98)	Srg_BB002
Storage	Grid services	Srg_BB001
Storage	High Energy User	Srg_BB001
Storage	Other	Srg_BB004
Domestic	-	Dem_BB001a
Non domestic	A1/A2	Dem_BB002b
Non domestic	A3/A4/A5	Dem_BB002b
Non domestic	B1	Dem_BB002b
Non domestic	B2	Dem_BB002b
Non domestic	B8	Dem_BB002b
Non domestic	C1	Dem_BB002b
Non domestic	C2	Dem_BB002b
Non domestic	D1	Dem_BB002b
Non domestic	D2	Dem_BB002b

Non domestic	Sui Generis	Dem_BB002b
Air conditioning	-	Lct_BB014
Demand	Block load	-
Electric vehicles	Hybrid car (non autonomous)	Lct_BB002
Electric vehicles	Hybrid LGV	Lct_BB004
Electric vehicles	Pure electric bus and coach	Lct_BB003
Electric vehicles	Pure electric car (autonomous)	Lct_BB001
Electric vehicles	Pure electric car (non autonomous)	Lct_BB001
Electric vehicles	Pure electric HGV	Lct_BB003
Electric vehicles	Pure electric LGV	Lct_BB003
Electric vehicles	Pure electric motorcycle	Lct_BB001
EV Charge Point	Car parks	Lct_BB012b, LCT_BB013b
EV Charge Point	Destination	Lct_BB012b, LCT_BB013b
EV Charge Point	Domestic 13A	Lct_BB010b
EV Charge Point	Domestic off-street	Lct_BB010b
EV Charge Point	Domestic on-street	Lct_BB010b
EV Charge Point	En-route / local charging stations	Lct_BB012b, LCT_BB013b
EV Charge Point	En-route national network	Lct_BB012b, LCT_BB013b
EV Charge Point	Fleet/Depot	Lct_BB011b
EV Charge Point	Workplace	Lct_BB011b
Heat pumps	District heating	Lct_BB009
Heat pumps	Domestic –Hybrid	Lct_BB006
Heat pumps	Domestic - Non-hybrid ASHP	Lct_BB005
Heat pumps	Domestic - Non-hybrid GSHP	Lct_BB005

Heat pumps	Domestic - Hybrid + thermal storage	Lct_BB006
Heat pumps	Domestic - Non-hybrid ASHP + thermal storage	Lct_BB005
Heat pumps	Domestic - Non-hybrid GSHP + thermal storage	Lct_BB005
Hydrogen electrolysis	-	Dem_BB009
Resistive electric heating	Direct electric heating	-
Resistive electric heating	Night storage heaters	-

[1] Ofgem Minded to Position on the Access and Forward-looking Charges Significant Code Review

Results and assumptions

Demand technologies

New demand in the South West licence area

Summary of modelling assumptions and results

Technology specification:

New property developments can have a significant impact on local electricity demand and therefore are included in DFES analysis. We categorise new developments as new domestic developments (houses) and non-domestic sites (e.g. factory/warehouse, offices, retail, sports & leisure etc.).

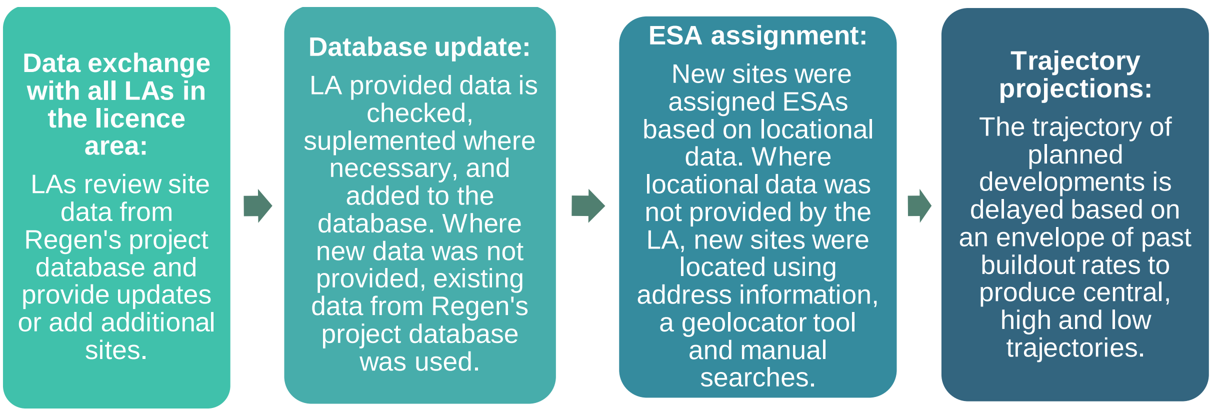
Data on planned domestic and non-domestic developments is gathered through engagement with all local authorities in the licence area. Alongside historic build rates, this is used to inform local-level projections for future housing numbers and non-domestic floorspace (sqm).

Process and assumptions:

Database update and ESA assignment

- Through engagement with the LAs, development plans are verified and used to update a database of new developments. These contain location, size, likely use (for non-domestic), development stage and planned buildout timescale.
- Every LA within the licence area was contacted, with the previously collected data presented for verification or modification. A SharePoint database allowed local authorities to view and update the data themselves. Over half of LAs provided new data through the SharePoint or directly to the project team. For the remaining local authorities, Regen's existing project database was used; this database was developed through previous DFES iterations.

Figure 4 - Summary of methodology for the assessment of new developments



- All sites are assigned an ESA:
  - Most could be carried over from Regen's existing project database.
  - For newly provided developments with locational data, ESAs were assigned using GIS mapping. Large sites near an ESA border were manually checked and split across the neighbouring ESA where appropriate.
  - The remaining sites are assigned ESAs using a geolocator tool and manual searches. The tool runs the names of the developments through the OpenStreetMap search tool and where the search fails, further individual investigation of the development is carried out to locate it.

- Some sites are provided by LAs without a buildout rate. For these sites, an estimate is modelled based on the development stage, type, and typical regional site development rates.
- For non-domestic analysis, LA provided site areas are converted into floorspace (sqm) using a conversion ratio specific to the type of development and derived from historic DFES data.
- The LAs were also asked about existing or draft decarbonisation strategies for energy, transport, waste, and heating in their local area. This data was used to inform analysis within the wider WPD DFES 2021.

Trajectory projections

Delay factors and historic build rates

- Planned developments peak in the medium term; it is likely that a proportion of these developments will be subject to delays. To reflect this, the model applies delay factors to planned buildout timescales. In this way, the location and scale of development is maintained, but the period over which the sites are built is extended.

Table 1 - Domestic delay factors, the percentage of domestic developments which are completed as planned, with the remainder delayed.

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030-2050
High	85%	75%	65%	60%	60%	60%	60%	75%	75%	75%
Central	75%	65%	55%	50%	50%	45%	55%	55%	55%	55%
Low	65%	55%	45%	40%	40%	40%	40%	40%	40%	35%

- Three historic domestic build rates are determined using the past ten years of build out data:
  - 'High' is an average of the three years with the highest build rates.
  - 'Central' is an average of the ten-year period.
  - 'Low' is an average of the three years with the lowest build rates.
- These delay factors and historic housebuilding rates are then used to define a central trajectory, a high growth trajectory and a low growth trajectory.
- There is limited historic build rate data available for non-domestic developments. The delay factors are similarly determined and applied to account for project delays for non-domestic sites.

Table 2 - Non-domestic delay factors, the percentage of non-domestic developments which are completed as planned, with the remainder delayed.

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030-2050
High	90%	90%	90%	90%	90%	70%	50%	55%	55%	55%
Central	80%	80%	80%	70%	70%	45%	35%	35%	35%	35%
Low	70%	70%	70%	60%	60%	35%	20%	20%	20%	20%

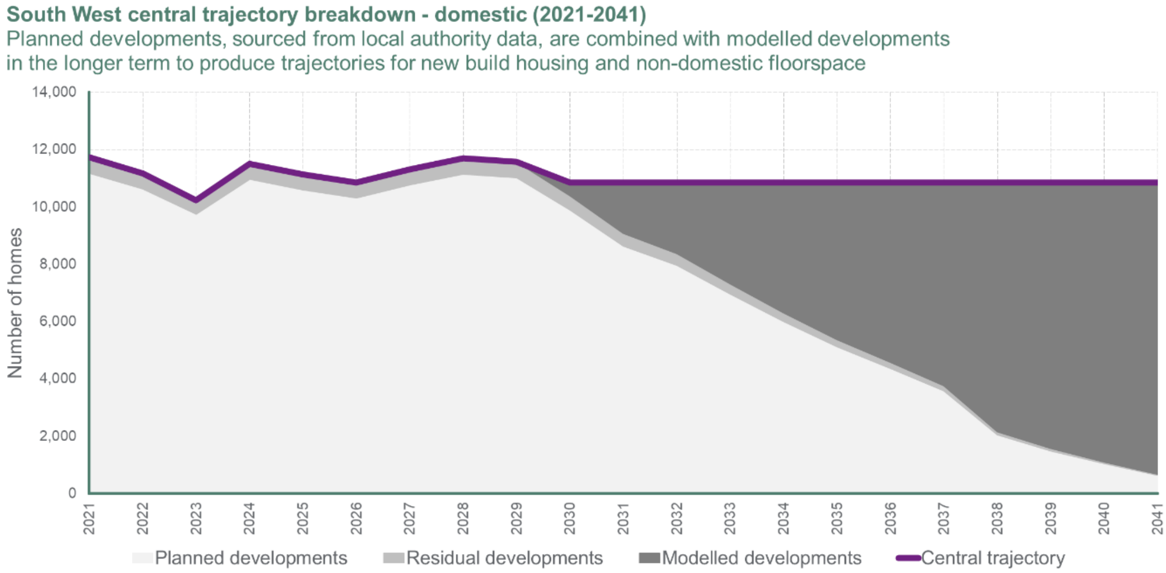
Residual sites and modelled development

- The domestic analysis seeks to capture all significant developments, defined as 20 homes or more. Analysis of previous new developments studies suggests this cut-off leaves about 5% of homes un-recorded, so these 'residual' small-scale sites are modelled and included in the final trajectory.
- There is a natural reduction in the data for planned developments after 2025 given the longer timeframe. Additional domestic developments are modelled post 2025, this 'modelled development' brings the long-term trajectory up to the levels of historic averages.
- There are no residual sites or 'modelled developments' for non-domestic developments.

Assigning trajectories to scenarios

- The 2021 FES shows no variation in new developments across the trajectories. However, for WPD's network planning the analysis applies the trajectories as follows:
  - **Leading the Way** uses the high trajectory.
  - **Consumer Transformation** and **System Transformation** use the central trajectory.
  - **Steady Progression** uses the low trajectory.

Figure 5



Results:

- For the South West licence area, the domestic central trajectory varies around an historic build rate of 11,000 homes annually.
- The non-domestic central trajectory grows from 300,000 sqm of floorspace annually to 600,000 sqm by the mid-20s.
- Of the planned non-domestic developments, 35% is factory and warehouse and 25% is office space.
- The Clyst Honiton ESA has the highest number of domestic developments projected to build out: over 8000 and driven by the ongoing development of Cranbrook town over multiple sites of 1000 homes or greater.
- The Clyst Honiton ESA also has the greatest amount of non-domestic floorspace due to be developed: 460,000 sqm and driven by the Clyst Honiton Skypark (200,000 sqm) and the Exeter Science Park (75,000) both awaiting construction.
- These projections also inform the analysis of domestic technologies such as electric vehicles, heat pumps and rooftop solar PV. The spatial data from the local plans define where on the WPD network these technologies may be located.

Figure 6

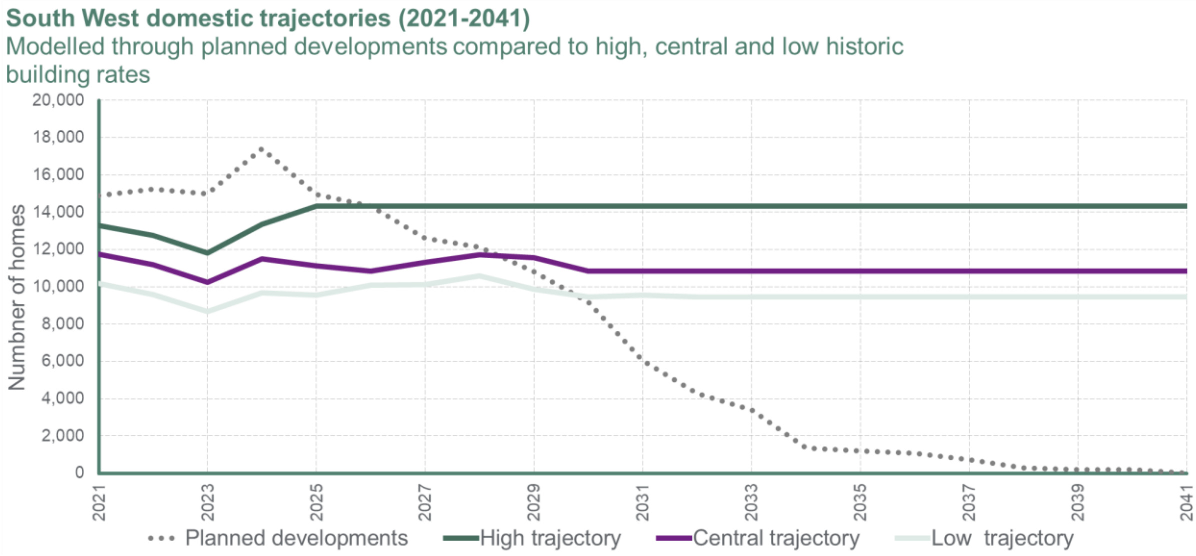
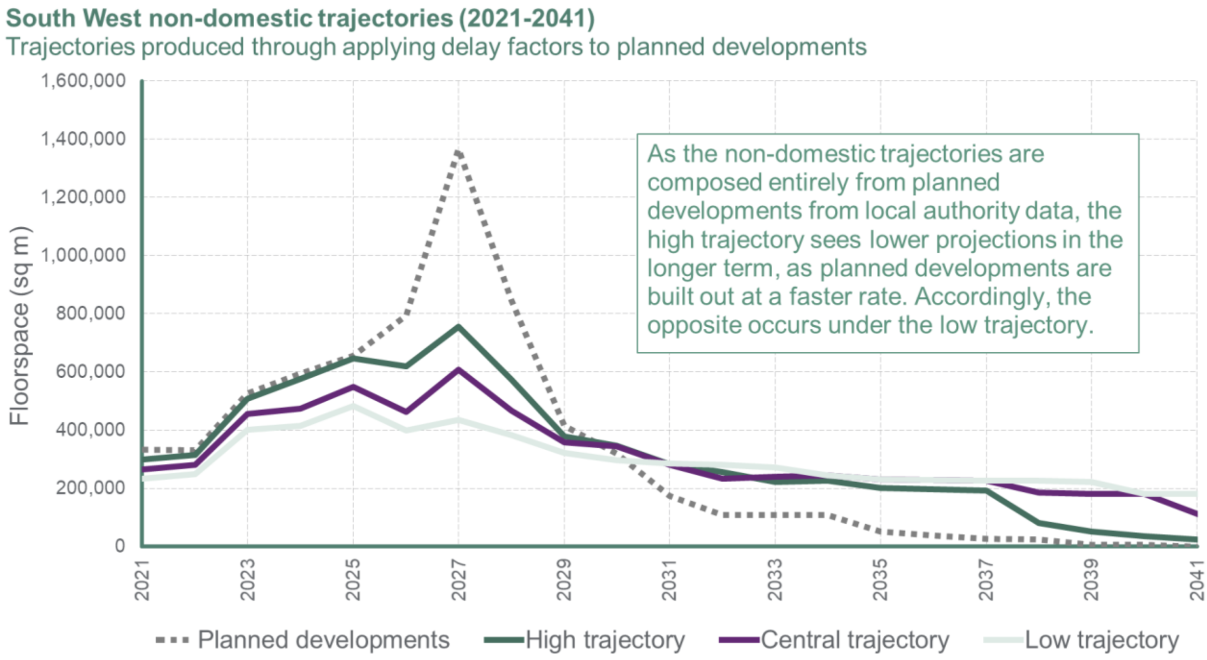


Figure 7



Stakeholder engagement:

- The initial stage of this process is reliant on engagement with LAs in the licence area. Over half of LAs provided new data, through the SharePoint or directly to the project team. For the remaining local authorities, Regen's existing project database was used.
- With many LAs engaging directly with the process, the projections are based on the most accurate and up to date information available.
- Some LAs were not able to provide information within the timeframe of the project, especially due to resourcing pressures as a result of the ongoing COVID-19 pandemic.
- Regen's project database ensured that all LAs were represented with recent high granularity development data.
- Alongside the new developments data exchange, the LAs were also asked about existing or draft decarbonisation strategies for energy, transport, waste, and heating in their local area. This data was used to inform analysis within the wider WPD DFES 2021.

Heat pumps in the South West licence area

Summary of modelling assumptions and results

Technology specification:

Domestic dwellings where a heat pump is the primary source of space heating and hot water. This category is divided into a number of technologies and sub-technologies, based on the heating technology and configurations that represent different loads on the electricity distribution network:

- Non-hybrid heat pumps, powered purely by electricity - Building block Lct_BB005. This is subdivided into:
  - Air source heat pumps without thermal storage
  - Air source heat pumps with thermal storage (in the form of a hot water cylinder or a phase-change material thermal store)
  - Ground source heat pumps without thermal storage
  - Ground source heat pumps with thermal storage
- Hybrid heat pumps, a combination of a heat pump and a secondary non-electric heat source that can be used at times of peak electricity demand or high electricity prices - Building block Lct_BB006.
  - For the purposes of the DFES, the fuel of the secondary heat source, such as biofuel, fossil gas or hydrogen, is not broken out in the projections.
- District heat network heat pumps, specifically houses connected to a network of hot water provided via a large-scale heat pump – Building block Lct_BB009

Data summary for heat pumps in the South West licence area:

Thousands of dwellings		Baseline	2025	2030	2035	2040	2045	2050
Non-hybrid air source heat pumps (of which have thermal storage)	**Steady Progression**	16 (0)	29 (6)	100 (21)	199 (41)	311 (63)	361 (74)	402 (82)
	System Transformation		39 (7)	74 (15)	139 (33)	223 (58)	312 (94)	357 (110)
	Consumer Transformation		55 (9)	216 (40)	449 (87)	741 (159)	921 (220)	960 (253)
	Leading the Way		126 (24)	376 (91)	597 (157)	749 (248)	778 (299)	801 (321)
Non-hybrid ground source heat pumps (of which have thermal storage)	**Steady Progression**	4 (0)	12 (3)	32 (8)	65 (18)	106 (33)	145 (46)	171 (58)
	System Transformation		12 (3)	34 (8)	54 (12)	77 (18)	84 (21)	89 (24)
	Consumer Transformation		18 (3)	64 (15)	185 (60)	327 (125)	439 (184)	521 (234)
	Leading the Way		37 (9)	137 (45)	244 (92)	339 (154)	415 (220)	448 (232)

Hybrid heat pumps	Steady Progression	0	0	7	16	26	27	27
	System Transformation		2	5	29	120	221	314
	Consumer Transformation		3	8	34	65	92	106
	Leading the Way		4	29	67	124	152	173
District heat network heat pumps	Steady Progression	0	5	8	8	9	10	11
	System Transformation		5	9	20	33	45	48
	Consumer Transformation		6	10	23	42	59	69
	Leading the Way		5	9	21	40	57	68

Summary:

- The South West licence area has a much higher proportion of off-gas homes compared to the national average, with an accordingly higher proportion of homes on oil, LPG and resistive electric heating. This results in an accelerated uptake of heat pumps in the near term, as off-gas homes are targeted at a national level.
- In line with potential options for decarbonising heat nationally, there is a dramatic shift to low carbon heating in the South West licence area in all three of the net zero scenarios. Under **Consumer Transformation** and **Leading the Way**, this results in heat pumps becoming the predominant domestic heating technology in the South West by 2050.
- Under **System Transformation**, decarbonisation of heat on a national level is driven by hydrogen, either through standalone boilers or hybrid heat pumps. However, the higher proportion of off-gas homes in the South West results in higher uptake of non-hybrid heat pumps, as availability of hydrogen from domestic heating is assumed to be in-line with the current availability of fossil gas heating.
- Bristol, the largest population centre in the South West licence area, sees roll-out of a number of planned heat networks[2], significantly influencing the uptake of district heat network heat pumps in the licence area in the near term. This is expanded across Bristol, and other urban centres in the licence area such as Exeter and Plymouth under the three net zero scenarios.

Modelling assumptions and results:

Baseline

- The South West licence area has an estimated 20,000 dwellings heated via a heat pump, of which 16,000 are thought to be on air source heat pumps, with the remaining 4,000 on ground source heat pumps.
- This baseline has been derived through analysis of EPC records, RHI data and WPD data on heat pump installations.
- Due to lack of evidence, the modelling assumes no thermal storage for existing heat pumps.
- The modelling suggests that around 1.3% of homes in the South West are heated by a heat pump. This is twice the national average of 0.6% of homes.
- This is most likely due to higher levels of off-gas housing, detached and semi-detached homes, and owner-occupied homes.
- The primary deployment driver for domestic heat pumps in existing homes in recent years has been the domestic RHI. 15% of heat pumps accredited by the RHI have been in the South West licence area.

Near-term (April 2021 to March 2025)

- All six forms of domestic heat pump heating have modelled holistically at a national and regional level, alongside resistive electric heating and non-electric heating. This has been achieved through applying scenario trajectories to 36 dwelling archetypes, based on current heating technology, building type, tenure and district heating potential.

Non-hybrid heat pumps

- In the near term, heat pump deployment ramps up in every net zero scenario, as the UK government looks to achieve 600,000 heat pump installations annually by 2028[3]. This ambition is achieved in the **Consumer Transformation** scenario, and exceeded under **Leading the Way**.
- As per the UK government's consultation on future support for low carbon heat[4], off-gas buildings are likely to be targeted in the near-term, supported through schemes such as the Clean Heat Grant[5]. As a result, the uptake of heat pumps in the South West licence area is ahead of the national trajectory.
- Heat pumps are assumed to be combined with thermal storage in 30% of new installations in all scenarios unless the heat pump is combined with a resistive electric back-up element instead. This is based on the proportion of homes with a hot water cylinder, as per the English Housing Survey[6], and weighted towards larger houses due to the greater average floorspace.
- In the near-term, most new build homes are expected to continue installation of fossil gas and resistive electric heating systems in all scenarios. However, under **Consumer Transformation** and **Leading the Way**, heat pump installations in new builds increase ahead of the Future Homes Standard implementation in 2025.

Hybrid heat pumps

- Hybrid heat pumps see minimal uptake in the near-term. Fully electric solutions are preferred under **Consumer Transformation** and **Leading the Way**, while existing gas, oil and LPG heating systems remain installed under **System Transformation** and **Steady Progression**.

District heating heat pumps

- Near-term modelling of district heating heat pumps directly uses data from HNDU and HNIP[7], the Heat Networks Planning Database[8], and direct engagement with local authority planners.

- Over ten district heating pipeline projects were identified, including in Bristol, Exeter, Plymouth, East Devon and Bath.
- However, only seven of these projects were planning to be heated via a heat pump, with the remainder heated by waste heat, Energy from Waste CHP or fossil gas CHP.
- The location and numbers of domestic customers for each pipeline heat network were ascertained, and directly reflected in every scenario.

Medium-term (April 2025 to March 2035)

Non-hybrid heat pumps

- Non-hybrid heat pumps continue to be installed in off-gas homes throughout the 2020s. In larger or less well-insulated houses, both air source and ground source heat pumps are installed alongside thermal storage.
- In areas of denser population, such as terraced houses and flats, GSHP installations are likely to connect to shared ground loops. This reduces the installation cost on a per-home basis, compared to each dwelling having an individual borehole or slinky loop[9].
- The FHS[10] is modelled to be implemented from 2025 under two scenarios, preventing new-build homes from connecting to the fossil gas network:
    - Under **Consumer Transformation** and **Leading the Way** the FHS is implemented as anticipated, resulting in heat pumps becoming the heating technology of choice for the vast majority of new builds. This is spread roughly equally across ASHPs, GSHPs on communal loops, and district heating heat pumps.
    - Under **System Transformation**, the FHS is implemented but circumvented through new build homes installing hydrogen-ready boilers, in anticipation of conversion of the fossil gas network to low carbon hydrogen in this scenario. As a result, heat pump uptake in new builds remains low.
    - Under **Steady Progression**, the FHS is not implemented. As such, the majority of new builds continue to install fossil gas boilers, and heat pump uptake in new builds remains low.

Hybrid heat pumps

- Hybrid heat pump uptake accelerates in the 2030s under the three net zero scenarios, as heat decarbonisation is targeted across the entire building stock.
- Under **Consumer Transformation** and **Leading the Way**, hybrid heat pumps are predominantly installed in off-gas houses, combined with a biofuel backup heater, and on-gas houses combined with a fossil gas or hydrogen boiler. Uptake is projected to be minimal in flats, owing to lower heat demand and space constraints preventing installation of two heating systems in a small home.
- Under **System Transformation**, hybrid heating systems are installed in some homes as mitigation against the higher price of distributed hydrogen compared to fossil gas.

District heating heat pumps

- Medium-term modelling of district heating heat pumps follows national trends, based on BEIS' 'Opportunity areas for district heating networks in the UK'[11] combined with housing density. The BEIS study correlates hotspots of heat demand with potential heat sources, which could be upgraded via a large-scale heat pump.
- This results in uptake in urban areas in the medium term where heat demand is particularly dense, such as Bristol and Plymouth.

Long-term (April 2035 to March 2050)

Non-hybrid heat pumps

- Under **Consumer Transformation** and **Leading the Way**, heat pumps become the dominant form of domestic heating in the UK. This includes a wholesale shift from fossil gas boilers to heat pumps in the 2030s and 2040s.
    - In the South West licence area, this results in around 1.5 million non-hybrid heat pumps by 2050 under **Consumer Transformation**, and 1.25 million under **Leading the Way**.
    - In both scenarios, ASHPs make up approximately 60% of non-hybrid heat pumps, with GSHPs making up the remaining 40%.
- Under **System Transformation** and **Steady Progression**, non-hybrid heat pump uptake is more limited.
    - Under **System Transformation**, this is due to the presence of hydrogen boilers and hybrid heat pumps as the primary low carbon heating technologies, which replace the majority of current fossil gas heating.
    - Under **Steady Progression**, progress towards heat decarbonisation is slow, with many homes still heated by fossil gas in 2050 as the UK fails to meet its net zero target.
- Thermal storage has potential to increase in all scenarios, especially as new phase-change thermal stores come to market and consumers become more engaged with energy consumption. By 2050, over half of retrofit non-hybrid heat pumps are alongside a form of thermal storage under **Consumer Transformation** and **Leading the Way**. This includes retrofitting of thermal storage onto heat pump installations that were previously installed without.
- For new build homes, the medium-term assumptions continue to 2050. In developments in more densely populated areas, district heating heat pumps are favoured over standalone non-hybrid heat pumps.

Hybrid heat pumps

- Hybrid heat pumps see rapid uptake under **System Transformation** as hydrogen becomes available as a heating fuel on a national level, replacing the fossil gas network.
    - In this scenario, the majority of hydrogen is produced through reformation of natural gas. As a result of losses during the conversion and delivery of blue hydrogen, it is anticipated to be substantially more expensive than fossil gas for the end consumer.
    - This results in high levels of hybrid heat pump uptake, as heating via a heat pump is anticipated to be more cost-effective outside of the winter heating season than a standalone hydrogen boiler in many cases.

District heating heat pumps

- As per the medium-term, district heating heat pumps are deployed in denser urban areas and new housing developments under the net zero scenarios.

Figure 8

Number of domestic air source heat pumps by scenario
For the South West licence area

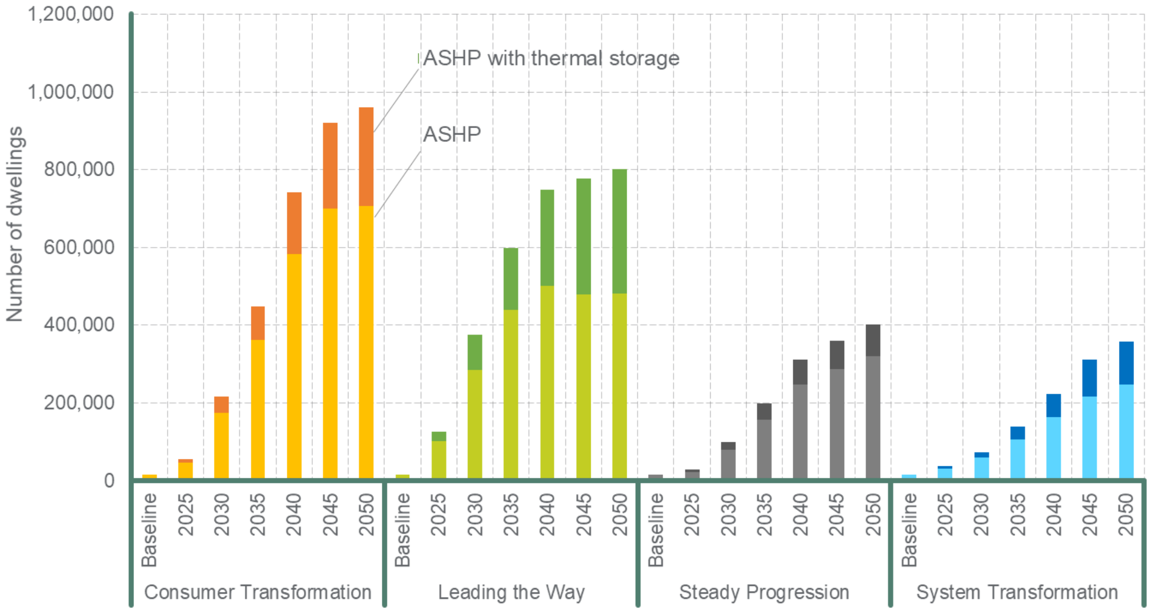


Figure 9

Number of domestic ground source heat pumps by scenario
For the South West licence area

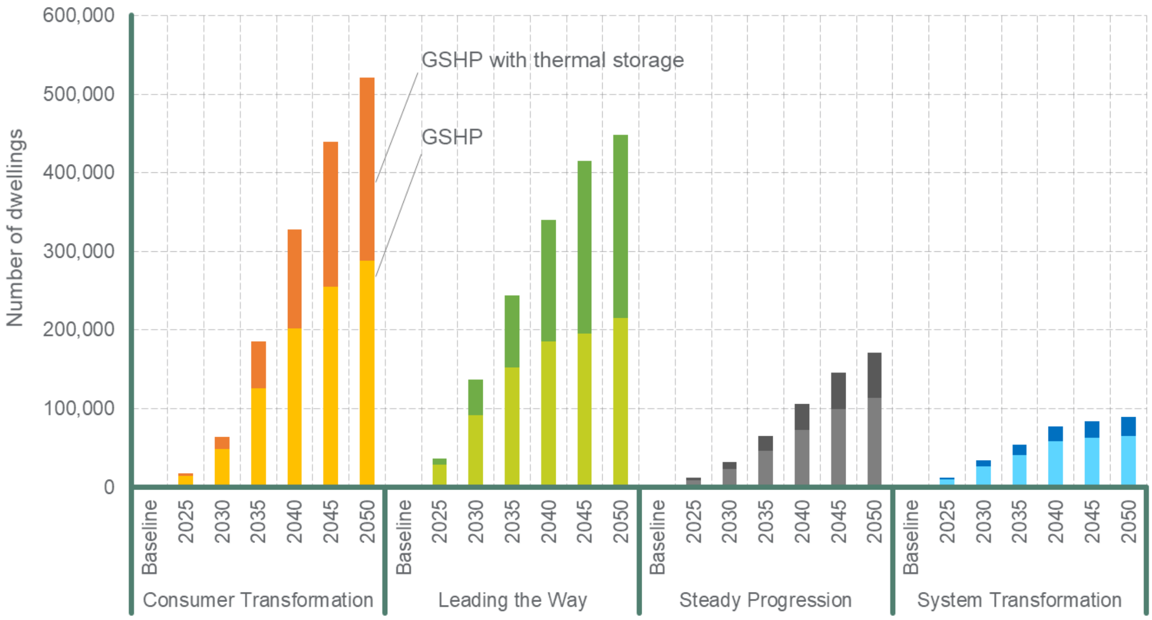


Figure 10

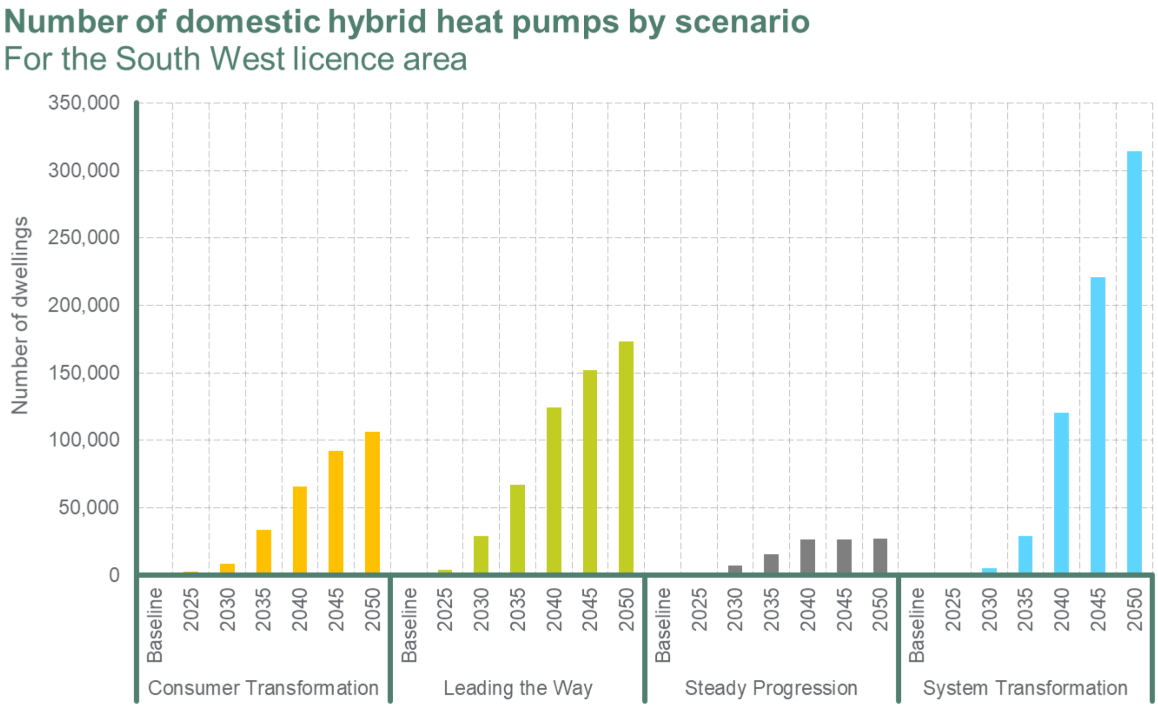
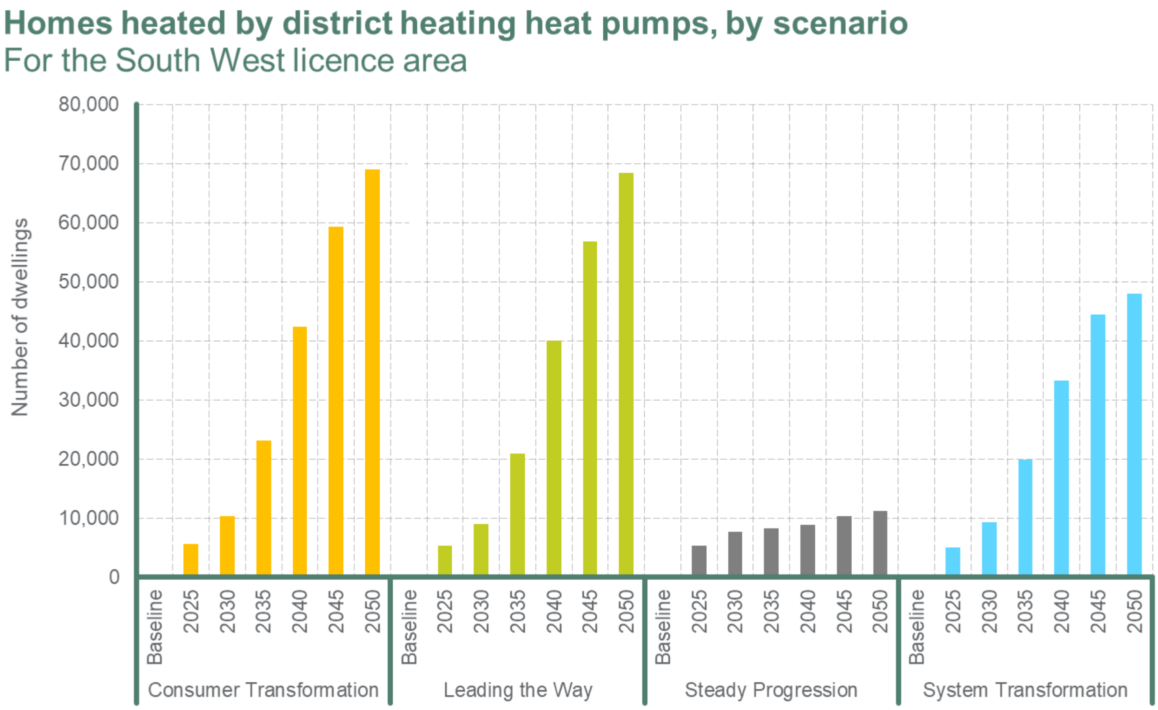
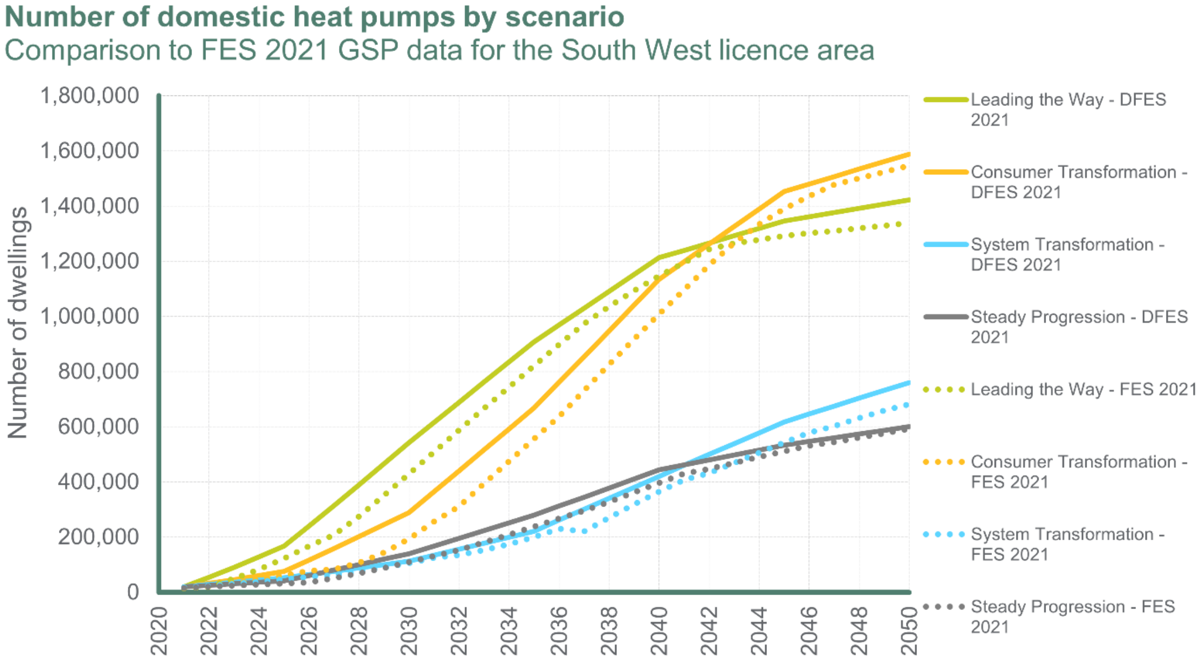


Figure 11



Reconciliation with National Grid FES 2021:

Figure 12



Results in this section relate to the FES 2021 data for the relevant GSPs within the South West licence area.

In the available GSP-level data, the National Grid FES 2021 does not split out district heating driven by heat pumps from other forms of district heating, such as biomass, gas CHP and waste heat. As a result, a direct reconciliation has not been undertaken.

The Building Block data provided in the FES 2021 classifies an 'ASHP with a resistive heating element' as a hybrid heat pump (Lct_BB006), whereas the DFES analysis considers this to be a variation of a non-hybrid heat pump (Lct_BB005). Accordingly, the reconciliation has been undertaken using combined figures for both non-hybrid and hybrid heat pumps.

- The rate of heat pump uptake, the type of heat pump, and the availability of alternative low carbon heating technologies are key, national-level assumptions that underpin much of the variance between the four scenarios.
- As a result, the DFES analysis has not looked to model these scenarios at a national level, but instead analysed how these scenarios may look on a regional and local level. Therefore, the analysis has strongly leant on the national FES outcomes for each heating technology as a starting point.
- In the near term, uptake of heat pumps in the South West is more ambitious in the DFES. The archetype-based heat modelling favours heat pump uptake in off-gas dwellings, houses, and owner-occupied or socially rented homes. In most of these metrics, the South West is above the national average.
- In the longer term, the DFES analysis aligns with the National Grid FES, reflecting national 2050 heat decarbonisation outcomes in the scenarios.
- The breakdown of thermal storage is not directly detailed in the FES. However, it is stated that 60% of heat pumps have thermal storage by 2050 under **Leading the Way**, versus just 30% under **Steady Progression**. This range has been reflected in the modelling of non-hybrid heat pumps at 40% under **System Transformation** and 50% under **Consumer Transformation**.

Factors that will affect deployment at a local level:

- The spatial distribution of heating technologies has been modelled holistically based on the existing heat technology in the home, the building type, the tenure of the household in question and the district heating potential of each geographic ESA.
- Heat pump uptake increases throughout each scenario. In the nearer term, the distribution of heat pumps is weighted more heavily towards houses rather than flats, and owner-occupied and socially rented dwellings rather than privately rented dwellings. However, all dwelling archetypes see heat pump uptake in all scenarios.
- Analysis of dwelling archetypes have been used to model the spatial distribution of each heat pump sub-technology. For example:
  - Owner-occupied detached and semi-detached houses are considered more likely to have thermal storage alongside a heat pump, as this type of dwelling is most likely to already host a hot water cylinder or have space to install any form of thermal store.
  - Terraced houses and flats are considered more likely to host a ground-source heat pump, due to the potential to connect to a shared ambient ground-loop in more densely packed residential areas.
  - Private rented houses and flats are modelled to see slower uptake of heat pumps compared to owner-occupied and socially rented dwellings, which typically have a greater impetus to install building improvements.
- Additionally, homes located where existing district heat networks are sited or planned, or located within areas with potential for district heating, see focussed uptake of district heating heat pumps.
  - A near-term pipeline of district heat projects was identified through data from HNDU and HNIP, alongside the Heat Networks Planning Database.
  - The potential for district heating heat pumps in the longer term was derived from BEIS' 'Opportunity areas for district heating networks in the UK', combined with Output Area-level data on housing density.
- Regen's engagement with local authorities has been used to weight near-term and medium-term projections towards authority areas with clear heat decarbonisation strategies. For example, ambition above the national trajectory for both standalone and district heating heat pumps in Bristol[12] has been reflected in the analysis.
- New build housing is also a key influencer of local deployment. New housing developments are modelled specifically based on local planning data, using the exact location of each development.

Relevant assumptions from National Grid FES 2021:

Assumption number	3.1.3 – Heat pump adoption rates
Steady Progression	Low disposable income and low willingness to change lifestyle means consumers buy similar appliances to today
System Transformation	Medium disposable income, an increase in energy prices relative to today through carbon price but low willingness to change lifestyle and consumer preference is to minimise disruption to existing technologies
Consumer Transformation	Medium disposable income, high energy prices relative to today through carbon price incentives and a change in zeitgeist drive behavioural change to adopt new heating technologies
Leading the Way	High disposable income, high energy prices relative to today through carbon price incentives and a change in zeitgeist drive behavioural change to rapidly adopt and experiment with new heating technologies
Assumption number	**4.2.27 – Uptake of hybrid heating system units***
Steady Progression	Gas boilers still dominant and very low levels of hybridization
System Transformation	Hydrogen boilers dominant and very low levels of hybridization
Consumer Transformation	Moderate levels of heating hybridization. Even in a highly electrified heat landscape the availability of other fuels makes hybridization cost optimal in certain localities
Leading the Way	The drive to get to net zero early means taking the best from each fuel source and each technology to achieve optimum overall outcome for individual consumers and the system at large

* note that this assumption relates to the National Grid FES definition of hybrid heat pumps. This includes ASHPs with a resistive electric back-up heater, which are considered as non-hybrid heat pumps in the DFES.

Stakeholder feedback overview:

Heat pumps	
Your comments to us	Our response
Stakeholders said that off-gas fossil fuel-heated homes and new build homes would be most strongly targeted for heat pump deployment over the next decade, with on-gas homes and households in fuel poverty the least targeted. However, all options were considered likely to be targeted to some degree.	We have used these factors in the distribution of heat pumps between the baseline and 2028, considering current heating technologies, fuel access and demographic factors for each licence area.

Stakeholders noted that WPD may not have sight of all installed heat pumps.	We construct a baseline of low carbon technologies such as heat pumps from an array of sources, including WPD data, RHI data and Energy Performance Certificates. We believe this yields a reasonably accurate baseline.
Stakeholders noted that the condition of the building stock is likely to play a significant role in the uptake of heat pumps in the near term, with local authorities encouraged to tackle the worst-performing stock via whole-house retrofit.	We have modelled heat pump uptake across all types of housing, with an accelerated uptake in dwelling archetypes that see higher rates of fuel poverty and poor energy efficiency.
Stakeholders asked whether new build housing would be designed to avoid the need for significant space heating.	As it stands, the Future Homes Standard would not achieve levels of efficiency akin to the Passivhaus standard, where space heating demand is minimised. As a result, we have modelled new build housing as still requiring some form of space heating, typically via a heat pump.

References:

EPC data, Census 2011, RHI data, English Housing Survey, Regen consultation with local stakeholders.

Resistive electric heating in the South West licence area

Summary of modelling assumptions and results

Technology specification:

A system using resistive electricity to provide primary space heat and hot water to domestic buildings, rather than driven by a heat pump. This has been subdivided into:

- Night storage heaters – dwellings heated by resistive electric heaters combined with a thermal store such as ceramic bricks, which are heated overnight on off-peak electricity and radiate stored heat during the daytime.
- Direct electric heaters – dwellings heated by electric heaters that directly radiate heat when required, also known as panel heaters.

There are no Open Networks Building Blocks for resistive electric heating.

Data summary for resistive electric heating in the South West licence area:

Thousands of dwellings		Baseline	2025	2030	2035	2040	2045	2050
Night storage heaters	Steady Progression	181	172	152	134	120	109	104
	System Transformation		178	158	136	96	54	39
	Consumer Transformation		178	152	132	105	77	70
	Leading the Way		153	133	108	102	112	123
Direct electric heaters	Steady Progression	86	82	68	59	48	36	28
	System Transformation		84	69	55	39	22	13
	Consumer Transformation		85	65	51	34	13	6
	Leading the Way		80	68	48	34	22	21

Summary:

- Resistive electric heating, particularly direct electric heating, has historically been much more expensive to run than heating via gas, oil or an electric heat pump. Households on resistive electric heating are disproportionately likely to be in fuel poverty, as a result.
- The number of households on resistive electric heating decreases in all scenarios, with more affordable to run options such as heat pumps and district heating coming forward. Direct electric heating, as the least affordable heating method, is targeted more in the near term. There is a shift from direct electric heating to night storage heating in homes where a wet heating system, like a boiler or heat pump, is not feasible.
- There are homes remaining on resistive electric heating in 2050 in every scenario, despite its decreasing number. In dwellings where heat demand is low, such as well-insulated flats and small houses, it may not be economical to install more capital intensive wet heating system such as a heat pump. There may also be homes where resistive electric heating is the only electrified option, such as due to planning or structural constraints in select listed buildings and high-rise apartments.

Modelling assumptions and results:

Baseline

- The South West licence area has an estimated 267,000 dwellings heated via some form of resistive electric heating, of which 181,000 are thought to be on night storage heaters, with the remaining 86,000 on direct electric heating.
- This baseline has been derived through analysis of EPC records, Census 2011 data and WPD data on domestic customers connected to an Economy 7 meter.
- Resistive electric heating is much more common in the South West compared to the national average, heating 17% of homes compared to 11% nationally.
- This is due to a combination of rural areas not connected to the fossil gas network, and highly urban areas such as Bristol, which features many high-rise apartment blocks heated electrically.
- Resistive heated houses (as opposed to flats) are particularly prevalent in the licence area, making up 10% of dwellings compared to 4% nationally. The South West is the only licence area where resistive heated houses outweigh resistive heated flats. This is in part due to the more remote nature of the licence area, with some significant population centres in Devon and Cornwall not connected to the gas network.

Near-term (April 2021 to March 2026)

- All domestic heating technologies, such as resistive heating, heat pumps and non-electric boilers, are modelled holistically at a national and regional level. This has been achieved through applying scenario trajectories to 36 dwelling archetypes, based on current heating technology, building type, tenure and district heating potential.
- The number of dwellings on resistive electric heating decreases in the near term in all scenarios, as households look to or are supported to switch to more economic forms of domestic heating.
- There is some flux in resistive electric heating in the near term, such as homes converting to gas heating through the Fuel Poor Network Extension Scheme[13], homes upgrading to more modern night storage heaters through the Energy Company Obligation[14], and homes converting to more efficient electric heating such as heat pumps and district heating.
- Under **Consumer Transformation** and **Leading the Way**, higher heat pump and district heat deployment in the near term relates directly to a greater decrease in resistive electric heating.
- **Leading the Way** sees particularly strong uptake of heat pumps in the near term, with the UK meeting and exceeding its target of 600,000 heat pump installations per year by 2028. This predominantly targets off-gas and new-build housing. The modelling assumes up to 15% of night storage heated houses are converted to heat pumps in the near term under this scenario. With this archetype especially prominent in the South West, this results in a strong decline in night storage heaters.
- Around 10% of new build properties currently install resistive electric heating, particularly new build flats and apartment blocks. This is projected to remain steady throughout the near term, regardless of the anticipated ban on gas connections in new build homes from 2025.

Medium-term (April 2026 to March 2035)

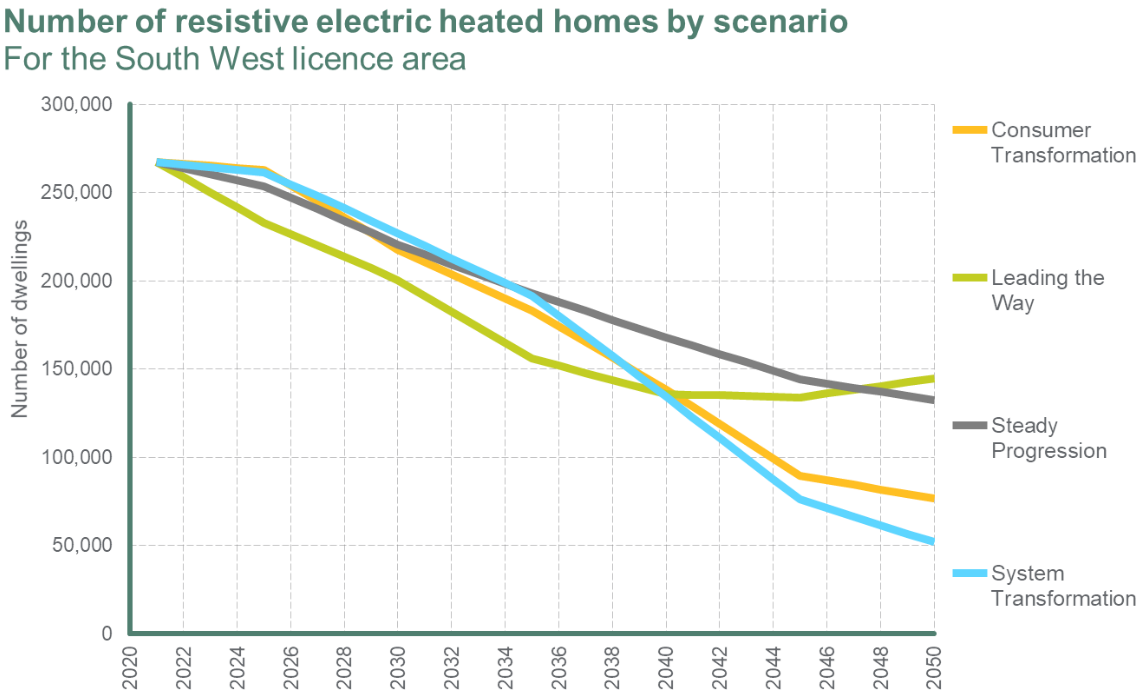
- Under **Consumer Transformation** and **Leading the Way**, accelerating heat pump and district heat deployment in the medium term results in further decreasing numbers of homes on resistive electric heating. This particularly impacts direct electric heating, as the most expensive from of electric heat.
- Under **Steady Progression** and **System Transformation**, more modest heat pump uptake is augmented by continued expansion of the fossil gas network and the rollout of a future hydrogen network respectively, similarly impacting resistive electric heating levels.

- By 2035, direct electric heating is reduced by between 31% under **Steady Progression** to 44% under **Leading the Way**.
- Under **Consumer Transformation** and **Leading the Way**, improvements to new 'phase-change' thermal storage results in up to 30% of direct electric heated homes converting to new, smart night storage heaters.
- By 2035, night storage heating is reduced by between 25% under **System Transformation** to 41% under **Leading the Way**. Over half of baseline night storage heaters convert to an alternative heating system by this point under **Leading the Way**. However, this is contrasted by new installations in new builds and conversions from direct electric heating.
- Direct electric heating is assumed to no longer be installed in new build homes beyond the near term in all scenarios, but night storage heating is still installed in a small minority of new developments. This decreases under the three net zero scenarios, as district heating and communal loop ground source heat pumps are preferred for denser new developments.

Long-term (April 2035 to March 2050)

- Direct electric heating continues to be marginal in all scenarios in the long term due to more affordable alternatives for low carbon heating. By 2050, direct electric heating levels are only 7% of the baseline under **Consumer Transformation**, compared to 33% of the baseline under **Steady Progression**.
- Under **Steady Progression**, the continued provision of the fossil gas network for heating results in a steady move away from resistive electric heating, despite the higher carbon emissions associated with fossil gas heating.
- Under **System Transformation**, the prevalence of hydrogen for domestic heating accelerates the move away from resistive electric heating in the longer term. As a result, this scenario has the least resistive electric heating by 2050.
- Under **Consumer Transformation**, continued roll-out of heat pumps accelerates the move away from resistive heating. This includes district heating and communal loop ground source heat pumps in flats and urban areas, where resistive electric heating is more common.
- **Leading the Way** has the highest level of societal engagement, energy efficiency and technological advances in smart, phase-change storage heating. This results in next-generation storage heating becoming a more affordable form of domestic heating in the longer term, and a source of demand-side response flexibility through smart heaters and Time Of Use Tariffs. As a result, this scenario sees an uptick in night storage heating in the latter years of the scenario timeframe.

Figure 13



Reconciliation with National Grid FES 2021:

There are no resistive electric heating numbers presented at a GSP level in the FES 2021. Therefore, reconciliation has been undertaken in relation to national FES 2021 results for resistive electric heating.

The domestic heat modelling has been calibrated against the FES scenarios. As a result, differences on a regional level are directly related to the existing housing stock and new build development rates in the licence area.

In the case of the South West licence area, direct electric heating and night storage heating reduce to a greater extent than the national trajectory. This is due to hosting higher levels of resistive electric heated houses, rather than flats, and lower levels of new house building.

Factors that will affect deployment at a local level:

- The spatial distribution of heating technologies has been modelled holistically based on the existing heat technology in the home, the building type, the tenure of the household in question and the district heating potential of each ESA.
- The distribution of homes replacing their resistive electric heating system is weighted more heavily towards houses rather than flats, and owner-occupied and socially rented dwellings rather than privately rented dwellings.
- New build housing is also a key influencer of local deployment of future smart storage heating. New housing developments are modelled specifically based on local planning data.

Relevant assumptions from National Grid FES 2021:

There are no assumptions in the FES 2021 that directly detail resistive electric heating. Assumptions around heat pump uptake, which strongly influences resistive electric heating, can be found in the Heat Pumps technology summary sheet.

Stakeholder feedback overview:

Resistive electric heating	
Your comments to us	Our response
Stakeholders said that resistive electric heating was most likely to remain in smaller houses and flats in the net zero future, rather than being replaced by heat pumps.	We have modelled resistive electric heating based on housing stock, existing heat technology and location, particularly accounting for the potential for district heating in urban rather than rural areas and the potential for resistive heat to remain in flats and smaller homes.
Stakeholders said that resistive electric heating would be replaced with heat pumps and district heating over time.	

References:

EPC data, Census 2011, English Housing Survey, Regen consultation with local stakeholders.

Electric vehicles in the South West licence area

Summary of modelling assumptions and results

Technology specification:

Electric vehicles (EVs) – including cars, buses and coaches, HGVs, LGVs and motorcycles, including Battery EVs and Plug-in Hybrid EVs.

Data summary for EVs in the South West licence area:

Thousands of EVs		Baseline	2025	2030	2035	2040	2045	2050
Battery EVs	Steady Progression	12	66	261	734	1,466	2,012	2,173
	System Transformation		85	382	1,154	1,951	2,113	1,989
	Consumer Transformation		159	706	1,646	2,042	2,048	1,924
	Leading the Way		157	790	1,778	2,062	1,926	1,543
Plug-in Hybrid EVs	Steady Progression	8	26	64	120	162	102	25
	System Transformation		26	60	90	61	16	0
	Consumer Transformation		19	37	49	28	2	0
	Leading the Way		26	53	40	14	0	0

Summary:

- At present, EVs (including Battery EVs and Plug-in Hybrid EVs) represent approximately 0.9% of all vehicles in the South West licence area. The GB average is 1.2%; therefore, the area currently has a below average uptake of EVs. The area is projected to increase uptake in line with the GB average by the late 2020s as EVs become ubiquitous in the net zero scenarios.
- The number of Plug-in Hybrid EVs in the licence area is 63% of the number of Battery EVs; this proportion is projected to reduce further in all scenarios, as Battery EVs become the dominant form of EV in the near term. The number of Plug-in Hybrids peaks in the 2030s in all net zero scenarios, followed by a decline to 2050.
- In the latter years of the scenarios, some autonomous EVs are projected. This is strongly dependent on technological advances and societal change, and as such have been directly aligned with national projections.

Modelling assumptions and results:

Baseline

- There are a total of 12,060 Battery EV cars in the South West licence area.
- There are a total of 7,600 Plug-in Hybrid EV cars in the South West licence area.

Near term (April 2021 – March 2025)

- The estimated uptake of EVs places the existing baseline at the bottom of a hockey stick curve of future uptake. Across all scenarios the uptake of EVs is expected to increase dramatically by 2025.
- It is projected that by 2025, there could be between around 66,000 Battery EVs in **Steady Progression** to 159,000 in **Consumer Transformation** – potentially up to a thirteen-fold increase by 2025.

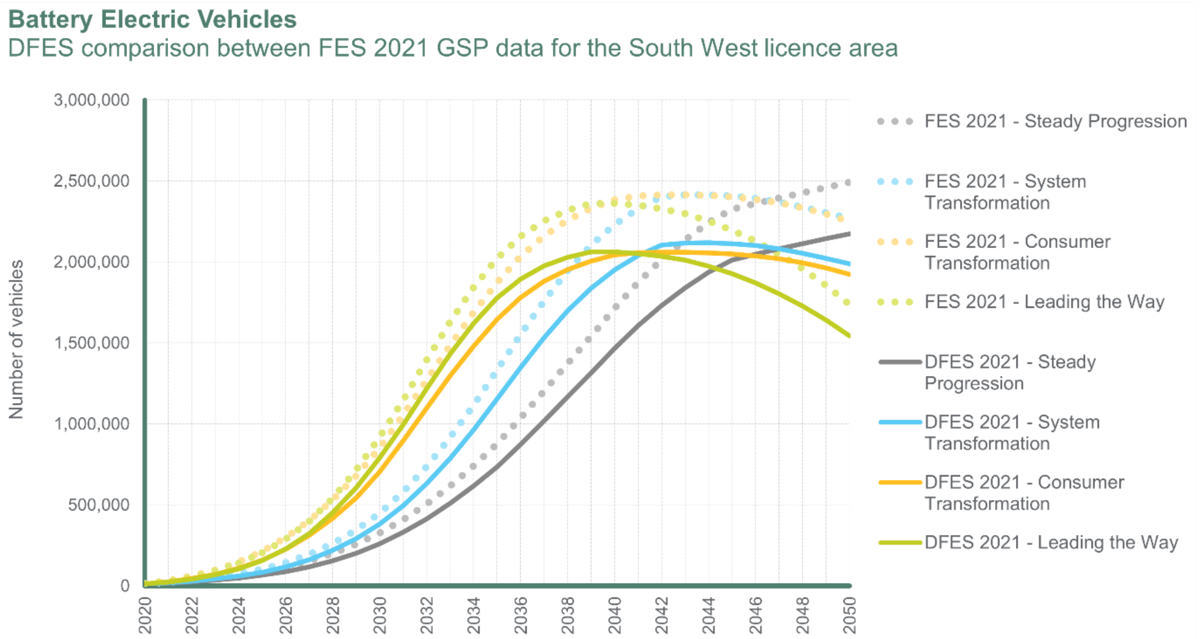
Medium term (April 2025 – March 2035)

- The uptake of EVs is expected to continue accelerating between 2025 and 2035 across all scenarios.
- **Steady Progression** is the scenario with the fewest estimated Battery EVs in 2035, with nearly 0.7 million. **Leading the Way** remains the scenario with the most, with nearly 1.8 million Battery EVs by 2035.
- EV uptake begins to slow in the mid-2030s as EV adoption approaches saturation, and only the hardest-to-electrify vehicle categories remain fossil-fuelled, such as HGVs. Furthermore, other factors contribute to uptake slowing, including the total number of vehicles on the road reducing, due to an increased use of public transport, vehicle sharing and active travel. These factors become more significant in the long term.

Long term (April 2035 – March 2050)

- The uptake of EVs continues to increase in **Steady Progression** in the long term. In this scenario Battery EVs total nearly 2.2 million by 2050.
- In **System Transformation**, the uptake of Battery EVs approximately flatlines from the early 2040s at just over 1.9 million.
- In **Leading the Way** and **Consumer Transformation**, the numbers of EVs reduces from the late 2030s and mid 2040s respectively. High levels of societal change in these scenarios, including an increased use of shared private vehicles and widespread switching to public and active travel, results in many homes opting to have one car, or no car at all.
- In **Leading the Way**, the number of Battery EVs and total vehicles reduces substantially, peaking at nearly 2 million before reducing to 1.5 million in 2050.

Figure 14



Reconciliation with National Grid FES 2021:

- The WPD DFES 2021 projections are broadly in line in the near term with the FES 2021 projections for this licence area, as reported for the Building Block ID numbers Lct_BB001, Lct_BB002, Lct_BB003, Lct_BB004'. However, in the medium and long term there is a lower peak in the DFES projections compared to the FES. Regen's total vehicle numbers are based on the number of vehicles in the South West licence area, using local DfT data.

Factors that will affect deployment at a local level:

- The spatial distribution of EVs in the near term is based on affluence, rurality, existing vehicle baselines and the distribution of on and off-street parking. However, in the late 2020s under all net zero scenarios uptake is assumed to be ubiquitous, and almost all consumers are assumed to have the same likelihood of adopting an electric vehicle, though the distribution will necessarily be weighted towards those customers who have yet to purchase an EV.

Relevant assumptions from National Grid FES 2021:

Assumption number	3.3.5 - Uptake of battery electric vehicles 4.1.25 - The rate of uptake of plug-in hybrid electric vehicles
Steady Progression	Battery EV adoption is slow and does not meet policy ambitions. Sales ban of petrol & diesel cars is pushed back to 2035, and vans to 2040, to protect UK car industry sales. Low uptake of BEVs in the Bus and HGV sectors out to 2050. Availability from manufacturers to meet EU emissions standards is met from demand by fleets looking to gradually reduce emissions (through PHEVs) and drivers who are unwilling to shift to BEVs. New PHEV sales banned in 2040.
System Transformation	The right conditions are not fully achieved to create the consumer confidence needed for the market to achieve the government's 2030 ban on petrol & diesel cars and vans. The bans for cars and vans are pushed back to 2032 and 2035 respectively. Uptake in (BEV) HGV and Bus sector is limited by strong Hydrogen Fuel Cell Vehicle uptake. Higher demand for Plug-in Hybrid EVs as a transitional vehicle due to a higher proportion of consumers reluctant to transition to BEVs. New Plug-in Hybrid EV sales banned in 2035
Consumer Transformation	The government target to ban sales of petrol & diesel cars and vans by 2030 is met. There is significant uptake in the bus sector and across suitable HGVs. Subsidy environment, falling battery costs and increased consumer willingness to accept BEVs limits PHEV growth. New (PHEV) sales banned in 2035.
Leading the Way	The government target to ban sales of petrol & diesel cars and vans by 2030 is met. Uptake in the HGV sector is limited by strong Hydrogen Fuel Cell Vehicle uptake. There is significant uptake in the bus sector. Subsidy environment, falling battery costs and increased consumer willingness to accept BEVs limits PHEV growth. New (PHEV) sales banned in 2035.

References:

Department for Transport data, Climate Emergency declaration data, Regen consultation with local stakeholders, Census 2011.

Electric vehicle chargers in the South West licence area

Summary of modelling assumptions and results

Technology specification:

Electric vehicle (EV) chargers – including eight charger archetypes of off-street domestic, on-street residential, car parks, destination, workplace, fleet/depot, en-route local and en-route national.

This relates to building blocks Lct_BB010a to Lct_BB013b.

Data summary for EV chargers in the South West licence area:

EV chargers		Baseline	2025	2030	2035	2040	2045	2050
Domestic off-street EV chargers (Thousands of chargers)	Steady Progression	9	30	127	384	749	998	1,051
	System Transformation		42	225	688	1,086	1,144	1,144
	Consumer Transformation		71	322	788	968	971	971
	Leading the Way		77	451	1,007	1,102	1,102	1,102
Domestic on-street EV chargers (Thousands of chargers)	Steady Progression	0	1	6	17	33	44	46
	System Transformation		1	5	16	30	33	34
	Consumer Transformation		3	18	42	54	57	60
	Leading the Way		2	13	35	49	60	72
Non-domestic EV chargers (Thousands of chargers)	Steady Progression	1	1	4	12	27	41	49
	System Transformation		1	6	21	41	51	55
	Consumer Transformation		3	11	28	36	42	46
	Leading the Way		3	11	28	36	42	47

Summary:

- At present, the licence area has a slightly above average level of non-domestic charging availability per electric vehicle. As EVs become more widespread, in the 2020s and 2030s, the installation rate of charging points accelerates nationwide, though some regional differences in the type and level of charging that is available are projected to be maintained.
- These projections aim to represent the envelope of the possible spread and rate of deployment of EV chargers. In many modelling areas, there is a lack of behavioural evidence and so interim assumptions have been made.

Modelling assumptions and results:

Baseline

- There is an estimated total of c. 1,000 public EV chargers in the South West licence area
- It is estimated that there are over 8,500 domestic EV chargers in the South West licence area, the vast majority of which are off-street chargers.
- The baseline is based on based on public EV charger registers combined with WPD data, and DfT vehicle registration data to model domestic chargers . Changes to EV registration data from DfT since WPD DFES 2020 has led to baseline changes in some areas.

Near term (April 2021 – March 2025)

- The estimated uptake of EV chargers places the existing baseline at the bottom of a hockey stick curve of future uptake. Across all scenarios, the uptake of EV changers is expected to increase dramatically in the near term.
- It is projected that by 2025, there could be between around 30,000 domestic off-street chargers under **Steady Progression** to 77,000 under **Leading the Way**, alongside several thousand domestic on-street chargers in each scenario.
- The highest scenario for non-domestic chargers, **Consumer Transformation**, sees 2,900 non-domestic chargers by 2025, totalling 128 MW of capacity. This encompasses public chargers, as well as private chargers for workplaces or vehicle fleets.
- As part of the **Leading the Way** scenario, Ofgem's 'minded to' decision on network charging[15] has a short-term effect of public charger installations. It is assumed that a proportion of EV chargers that are projected to be developed in 2022 will wait until the network charging rules change in 2023.

Medium term (April 2025 – March 2035)

- Charger installation rates are expected to continue accelerating between 2025 and 2035 across all scenarios.
- **Steady Progression** is the scenario with the lowest estimated EV charger capacity in 2035, with around 0.4 million domestic EV chargers and 12,000 non-domestic chargers. **Leading the Way** becomes the scenario with the highest number of domestic EV chargers, totalling over 1 million, while **Consumer Transformation** has the most non-domestic chargers, totalling c. 28,000 with a capacity of 1.1 GW.
- EV uptake begins to slow in the mid-2030s as EV adoption approaches saturation and only the hardest-to-electrify vehicles remain fossil-fuelled, such as HGVs. As a result, the installation rate of EV chargers also slows. Homes with multiple EVs are assumed not to purchase a second charger at the same rate as the first, and the demand for additional public charging reduces as most vehicles are now electrified in the net zero scenarios.

Long term (April 2035 – March 2050)

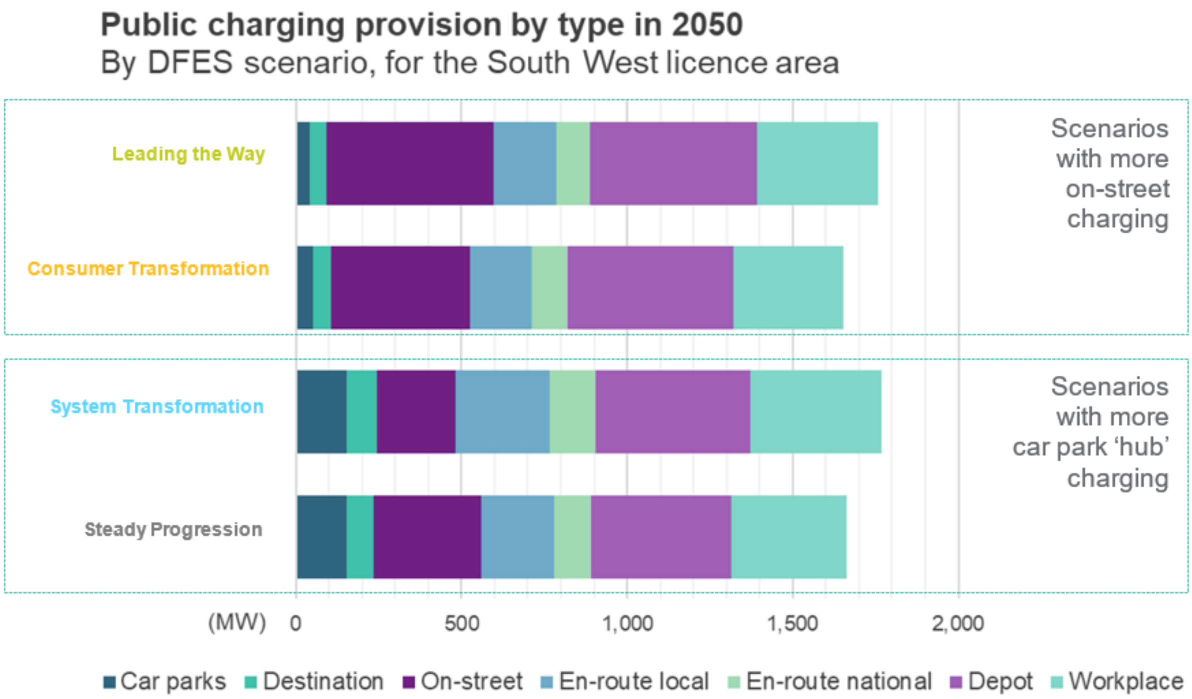
- While the uptake of EVs slows and then reduces in some scenarios in the long term, it is assumed that the number of off-street EV chargers will not reduce in line with EVs. An assumption is made that EV charger capacity will remain at the peak achieved in the years around 2040-2045, depending on scenario, rather than chargers decommissioning.
- The uptake of EVs and EV chargers continues to increase in **Steady Progression**, right up until 2050 when there are 1 million domestic EV chargers.
- In **Leading the Way** and **Consumer Transformation**, from the late 2030s and mid-2040s respectively as EVs approach market saturation and their numbers flat line, the capacity of domestic EV chargers similarly flat lines.
- In all scenarios, the modelled energy demand of EVs continues to increase through the 2040s, despite a reduction in EV numbers. This is predominantly due to increasing total mileage of vehicles. Therefore, non-domestic EV charging capacity also continues to increase.

Reconciliation with National Grid FES 2021:

- The EV charger building blocks are not included in the FES 2021 data at a GSP or national level. The bespoke EV charger projections in the DFES analysis are made using Regen's Net Zero Transport model that make use of FES EV projections and other assumptions where possible.
- Assumptions have been made as to the behaviour of EV and use of EV chargers based on stakeholder engagement that Regen has conducted with industry for several years. As more behavioural data and other evidence becomes available, these assumptions will be further refined in the future. These assumptions include:
  - Where each EV category will charge (at which EV charger archetype).
  - The predominant business models and EV charger utilisation at each charger archetype. For vehicle efficiencies, mileage and vehicle numbers, FES projections and assumptions were used.

Figure 15

Non-domestic and on-street EV charger capacity results, by scenario



regen transforming energy

WESTERN POWER DISTRIBUTION Serving the Midlands, South West and Wales

Factors that will affect deployment at a local level:

- Domestic off-street charger distribution is based on the uptake of domestic electric vehicles. As a result, the distribution of vehicles associated with on and off-street parking was evaluated, with the anticipated result that a feeder is more likely to see domestic off-street EV charging in more rural and more affluent areas where off-street parking exists.
- The spatial distribution of non-domestic chargers was analysed in a different manner for each archetype. En-route local and national charging locations were evaluated based on the density of local housing, the volume of local traffic, the distribution of existing petrol stations and the road classification the site is located on. Car parks, workplace and fleet depot locations were analysed from Ordnance Survey AddressBase data.
- The distribution analysis uses affluence as one of the key factors driving the uptake of EV chargers in the near term. For the more ambitious scenarios, from the mid to late 2020s, the underlying assumption is that EVs will become ubiquitous. Therefore, the growth in demand for EVs and EV chargers across all areas aligns in the longer term, regardless of affluence, off-street parking provision, rurality or other near-term factors.

Relevant assumptions from National Grid FES 2021:

Assumption number	4.2.13 - Level of Home Charging and other stated assumptions
Steady Progression	Charging at home is limited by a lack of via solution for those without off-street parking.
System Transformation	Emphasis on public rollout of fast chargers to allow rapid charging. More rapid and fast public charging is demanded from consumers.
Consumer Transformation	Charging predominately happens at home. Emphasis on home chargers, taking advantage of consumer engagement levels in flexibility. Leads to some disruption (e.g. reinforcing local networks).
Leading the Way	Charging happens similarly to how it happens today, with various types receiving investment to support an accelerated uptake of electric vehicles. Accelerated rollout of charging infrastructure at home and in public places. BEV cars smart charge at home or at the office, frequently pairing with on-site EV and batteries to encourage self-consumption.

References:

Department for Transport data, Climate Emergency declaration data, Regen consultation with local stakeholders, Census 2011,

Hydrogen electrolysis in the South West licence area

Summary of modelling assumptions and results

Technology specification:

This analysis covers the capacity of hydrogen electrolysers connected to the distribution network in the South West licence area. The analysis does not include electrolysers that are directly powered by renewable energy without a dedicated grid connection ('behind-the-meter') or large-scale electrolysers connected to the transmission network. Nor does it include CCUS-enabled hydrogen produced via the reformation of natural gas or other fossil fuels.

This technology pertains to Building Block ID number Dem_BB009 in the FES 2021 data; however, due to a lack of GSP level data for this building block, WPD DFES 2021 projections have been compared to FES 2021 figures at a national level.

Data summary for hydrogen electrolysis in the South West licence area:

Installed capacity (MW)	Baseline	2025	2030	2035	2040	2045	2050
Steady Progression	0	1	23	56	56	56	56
System Transformation		6	22	72	117	195	250
Consumer Transformation		2	21	323	499	1,085	1,584
Leading the Way		10	212	455	616	842	1,086

Summary:

- There is significant uncertainty around the development of hydrogen electrolysis as an emerging technology. The main sources of uncertainty are:
  - The split of capacity on the distribution network compared to the transmission network
  - The contribution of electrolytic hydrogen to national hydrogen aims, compared to CCUS-enabled hydrogen
  - The range of end-uses for hydrogen, including transport, industrial processes, aviation and shipping, power generation, and heating
  - Major government policy decisions that are still to be finalised
  - How far and how quickly hydrogen costs will fall
- There is a current lack of funding for hydrogen electrolysers, which may delay any 'first-of-a-kind' developments; however, this could change in light of the UK Hydrogen Strategy.
- Despite significant development not anticipated until after 2025, Ofgem's announcement of their minded-to decisions related to the Access SCR could be beneficial for hydrogen electrolysers, due to reduced network charges. This is modelled to be a factor under **Leading the Way** and **Consumer Transformation**.

- The South West licence area is not currently a focus area for hydrogen trial projects and there are no active hydrogen production facilities in the region. However, there is significant potential for future hydrogen electrolysis capacity due to strong renewable energy resources and the significant maritime sector in the South West[16], including Plymouth which has been granted "free port" status.
- The South West is a hub for maritime activity, with numerous ports along its coastline. In 2017, the maritime industry in the South West employed 76,700 people and had Gross Value Added of c. £3 bn[17]. The sector includes research organisations, luxury yacht builders, ports and dockyards, and offshore renewable energy expertise, which are all well suited to capitalise on the opportunity presented by hydrogen electrolysis.
- "Hydrogenesis"[18], a hydrogen powered ferry, operates on Bristol's floating harbour. This project initially included a hydrogen refuelling station on the dock; however, this has since been removed and instead hydrogen is purchased locally.
- The largest capacity of distribution-connected hydrogen electrolysers is projected under **Consumer Transformation** (1 GW) and **Leading the Way** (1.6 GW), due to a focus on electrolytic-hydrogen as a widespread zero carbon fuel for use in transport, industrial processes and heating.
- In contrast, the least capacity is modelled under **Steady Progression** (56 MW) reflecting limited government policy support for this technology and the assumption that high construction, production and construction costs limit the rollout of electrolysis.

Modelling assumptions and results:

Baseline (up to 31st March 2021)

- There is no capacity currently connected to the distribution network in the South West licence area.

Near term (April 2021 – March 2025)

- In the near term, **Leading the Way** and **System Transformation** dominate due to strong government support for hydrogen. This will likely be focussed on transport, including the introduction of hydrogen buses and HGVs.
- There are no proposed production projects in the South West licence area; however, there is activity linked to hydrogen research and development across the region:
    - Cornwall Marine Hydrogen Centre[19] – a new research and development facility in Falmouth. The 18-month project funded by the European Development Fund will explore the optimum setup for the storage and conversion of hydrogen into electricity, in the context of marine vessels
    - Undercover zero[20], a research and development centre based in Camborne, looking to establish a pilot laundry that produces and uses green hydrogen onsite
    - Research institutions including the Universities of Exeter, Bristol and Plymouth exploring the production and use of low carbon hydrogen.

Medium term (April 2025 – March 2035)

- Electrolytic hydrogen will be used for transport across all scenarios, favoured over CCUS-enabled hydrogen due to its purity.
- As a result, hydrogen electrolyser capacity is likely to increase in the medium term across all scenarios, driven by the uptake of hydrogen-fuelled heavy vehicle fleets and the introduction of mainstream hydrogen fuel cell public transport. This transition to low carbon heavy vehicles will be further incentivised by wider transport decarbonisation policy measures, such as the ban on the sale of new petrol and diesel cars by 2030.
- Under **Consumer Transformation** and **Leading the Way**, it is expected that hydrogen electrolysis will achieve cost parity with CCUS-enabled hydrogen by the mid-2030s.

- From consultation with electrolyser manufacturers, 5 MW and 10 MW electrolyser units are anticipated to become commercially viable in the medium term. This will allow existing and new sites to scale up their installed capacity.
- **System Transformation** does not see electrolysis reaching cost parity in the same timeframe, so CCUS-enabled hydrogen is the favoured production method, particularly for decarbonising industrial clusters.
- Under **Steady Progression**, there is very little policy support for hydrogen production in general.
- As a result of these sector developments, **Consumer Transformation** and **Leading the Way** see unprecedented growth in capacity between 2025 and 2035, with 321 MW and 445 MW of additional capacity, respectively. This growth in capacity is in line with the UK government's target of 5 GW clean hydrogen capacity by 2030.
- In contrast, **System Transformation** and **Steady Progression** see limited growth in capacity in the medium term, with 66 MW and 55 MW of additional capacity, respectively.

Long term (April 2035 – March 2050)

- In the long term, electrolysers are expected to scale their capacity by increasing the number of modules connecting to a compressor, which means that the development of new sites is likely to slow, and instead, existing locations are likely to be expanded to cater for higher demand.
- **Leading the Way** and **Consumer Transformation** continue to experience significant growth in hydrogen electrolyser deployment, seeing more than a doubling of capacity in each scenario between 2035 and 2050.
- This is due to a number of factors, including:
  - wider hydrogen sector developments, i.e., the repurposing of large-scale storage facilities for hydrogen and a decrease in upfront costs, as hydrogen electrolyser capacity increases across the UK
  - demand for electrolytic hydrogen from a variety of sectors, including heating, industrial demand, road transport, power, shipping, and aviation
  - the coupling of hydrogen electrolysis with renewable generation in these high-renewables scenarios.
- In **Consumer Transformation**, electrolysers are located close to demand as a national hydrogen network is not expected. This results in more, small-scale electrolysers connecting to the distribution network, close to demand. In 2050, electrolyser capacity reaches 1.4 GW, the highest of the four scenarios.
- The South West licence area has Triassic salt field basins around Somerset that could be used for hydrogen storage in the future. If, upon exploration, these are found to be suitable, large-scale hydrogen production facilities could locate in these areas, as this would reduce the hydrogen supply chain and ultimately reduce the cost of hydrogen. This is most likely to influence the location of hydrogen electrolysis capacity under **Consumer Transformation**.
- In **Leading the Way**, a national hydrogen transmission network allows production capacity to increase rapidly. This could favour transmission-scale production, so the growth of hydrogen electrolyser capacity on the distribution network is likely to taper off from 2035, resulting in 1 GW connected by 2050.
- **System Transformation** and **Steady Progression** have significantly lower electrolyser capacity connecting by 2050, due to a focus on CCUS-enabled hydrogen.

Key modelling assumptions:

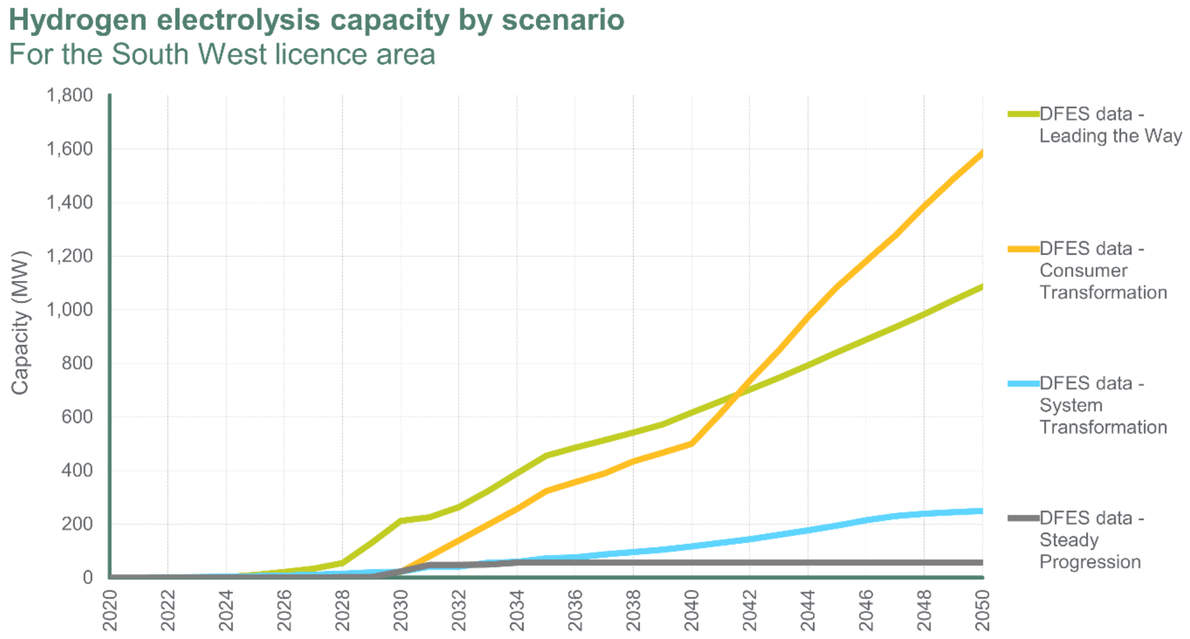
- **Leading the Way**, **Consumer Transformation** and **System Transformation** have been modelled with total GB capacity split between the transmission and distribution networks. In 2050, distribution connected capacity is modelled to account for 25%, 70% and 10% of the total capacity, respectively.
- **Steady Progression** is the only scenario to have all grid-connected hydrogen electrolysis capacity (100%) modelled on the distribution network.
- All scenarios project electrolytic hydrogen to be used in transport applications. Hydrogen refuelling infrastructure is likely to be co-located with existing petrol stations, particularly ones with large HGV fuelling demand.
- In scenarios where CCUS-enabled hydrogen is also present in the energy mix, it is assumed this is used to decarbonise existing high-carbon hydrogen production and the majority of industrial clusters.
- As a new technology, it is not clear how electrolysers co-located with renewable generation will connect to the grid. It is therefore assumed that hydrogen production co-located with renewable generation will connect to the same network as the renewable generation site itself.
- Storage is an important factor in the scaling up of hydrogen production; however, co-locating with large-scale storage facilities is more likely to result in transmission scale hydrogen electrolysers, thus this factor is not as heavily weighted as others for distribution-scale electrolysis.

From engaging electrolyser developers, a number of factors influencing the location of sites were identified, as seen in Table 3. These factors were weighted based on the assumptions underpinning the four FES scenarios and used to create licence area projections.

Table 3 - Locational factors used in the modelling of hydrogen electrolysis capacity, by scenario

Factor	Leading the Way	Consumer Transformation	System Transformation	Steady Progression
Industrial energy demand/clusters	X	X		
Heavy transport demand (HGVs)	X	X	X	X
Large-scale hydrogen storage options	X	X	X	
Location of major ports and maritime activity	X	X	X	
Access to the gas network	X		X	X
Distributed wind generation	X	X	X	
Distributed solar generation	X	X	X	
Rail network and associated infrastructure	X	X	X	
Existing grey hydrogen production	X	X		
Innovation/production projects	X	X	X	X

Figure 16



Reconciliation with National Grid FES 2021:

This technology pertains to Building Block ID number Dem_BB009 in the FES 2021 data; however, due to a lack of GSP level data for this building block, reconciliation is difficult. Instead, WPD DFES 2021 projections have been calculated as the distribution network proportion of FES 2021 grid-connected hydrogen electrolysis capacity at a national level. These were calculated based on the locational factors outline in Table 3, including the location of existing hydrogen production sites, large industrial clusters and heavy transport demand.

- Under **Leading the Way**, WPD DFES 2021 models 2% of the FES 2021 national grid-connection hydrogen electrolysis capacity to be connected to the distribution network in the South West licence area. **Consumer Transformation** (4%) and **System Transformation** (1%) have assumed there is capacity on both the transmission and distribution networks.
- **Steady Progression** models 4% of FES national capacity to be connected to the distribution network in the South West licence area, with all capacity assumed to be connected to the distribution network.

Factors that will affect deployment at a local level:

The spatial distribution of hydrogen electrolysers is highly uncertain, due to a number of factors, including:

- the potential for hydrogen electrolysers to be co-located with existing or new distributed renewable generation
- the split of electrolysis capacity on the distribution network compared to the transmission network
- the construction of a national hydrogen network that would be able to transport hydrogen around the UK
- the location of large-scale storage facilities, which have not currently been explored for hydrogen storage.

Stakeholder engagement:

As part of the WPD DFES stakeholder engagement process, Regen delivered a series of webinars with WPD in June 2021. Participants fed back that green hydrogen would be best used to decarbonise existing hydrogen production, closely followed by use as a transport fuel. It was considered that co-location with renewable generation is the most likely hydrogen business model and is likely to gain traction in the near and medium term. Medium-scale electrolysers serving industrial clusters was also considered to be a viable business model in the medium term. This feedback influenced the DFES analysis by confirming the influence of renewable generation and industrial clusters on the location of hydrogen electrolysers on the distribution network.

As part of the WPD DFES 2021 analysis, ITM Power, one of the UK's leading hydrogen electrolyser manufacturers, was consulted. They highlighted the potential for electrolysis production units to be used in industrial clusters, at transport hubs and in the shipping and aviation sector. They also highlighted a longer-term opportunity to co-locate with offshore wind. There was strong agreement with the modelling approach in the DFES, particularly the focus on matching electrolytic hydrogen supply to a number of end use sectors.

Relevant assumptions from National Grid FES 2021:

Assumption number	4.2.19 - Hydrogen (electrolysis exc. from nuclear)
Steady Progression	High costs limit rollout of electrolysis – used mainly in transport.
System Transformation	Competition from SMR* limits rollout of electrolysis – used mainly in transport. Electrolysis mainly from curtailed wind. SMR covers heat.
Consumer Transformation	Electrolysis used to decarbonise heat, transport and some industrial and commercial – medium as begins later than in **Leading the Way**.
Leading the Way	Electrolysis used to decarbonise heat, transport and industrial and commercial, but rollout starts in the mid-2020s.

*Steam Methane Reformation – a process of producing hydrogen from natural gas or other fossil fuels.

References:

IEA hydrogen project database, FES 2021 data workbook, Network Rail Traction Decarbonisation Strategy, consultation with ITM Power, University of Nottingham, UK Hydrogen Strategy, National Atmospheric Emissions Inventory, BEIS energy consumption dataset, Department for Transport local authority vehicle miles data, UK Carbon Capture and Storage Research Centre, 2011 Census data

Air conditioning in the South West licence area

Summary of modelling assumptions and results

Technology specification:

Number of domestic air conditioning units, based on a typical portable or window-mounted air conditioner.

Technology building block: Lct_BB014 – A/C Domestic units

Data summary for air conditioning uptake in the South West licence area:

Air conditioning units (thousands)	Baseline	2025	2030	2035	2040	2045	2050
Steady Progression	10	18	35	69	144	293	586
System Transformation		16	29	55	101	186	339
Consumer Transformation		16	29	52	98	180	327
Leading the Way		10	10	10	10	10	10

Summary:

- Air conditioning is currently rare in domestic settings in the UK, with just over 1% of homes currently containing an air conditioning unit.
- In the South West licence area, modelling suggests around 0.7% of homes currently have an air conditioning unit.
- Increased summer temperatures, extended heat waves and reducing costs of air conditioning units may contribute to increased uptake over the coming decades.
- The UK building stock is not optimised for passive cooling. This could drive increased levels of active cooling, such as air conditioners, as temperatures increase.
- Air conditioning uptake is likely to be focussed in urban areas such as Bristol, due to the 'heat island effect' causing increased temperatures in built-up areas[21].
- Given the minimal baseline and uncertainty around future cooling demand and cooling methods, there is a broad range of scenario outcomes. This results in minimal uptake under **Leading the Way**, and air conditioning becoming commonplace under **Steady Progression**.

Modelling assumptions and results:

Baseline

- There is limited baseline data on domestic air conditioning levels in the UK. A 2016 report by Tyndall Manchester suggested that 1-3% of UK households reported some form of air conditioning[22], equating to around 200,000-800,000 air-conditioned homes.
- A global assessment of the air conditioner market[23] suggested 110,000 'Room Air Conditioners' were sold in the UK in 2018, following year-on-year growth of 12% over the previous six years. However, this figure does not only account for new domestic air conditioners, but also small-scale commercial air conditioning and the replacement of existing units.
- For the purposes of this assessment, we have aligned with the National Grid FES 2021 air conditioning demand data, from which we have derived a national baseline of 292,000 domestic air conditioner units.
- Using regional temperature data, numbers of urban homes, and total number of homes, this national figure was disaggregated to determine a regional baseline.
- This results in 10,000 domestic air conditioning units in the South West licence area baseline.
- The baseline modelling assumptions have been updated since the WPD DFES 2020. This results in fewer air conditioning units in the licence area baseline. Compared to previous studies, a higher proportion of the national baseline is modelled to be located in London and South East England, reflecting temperature data and urban density.

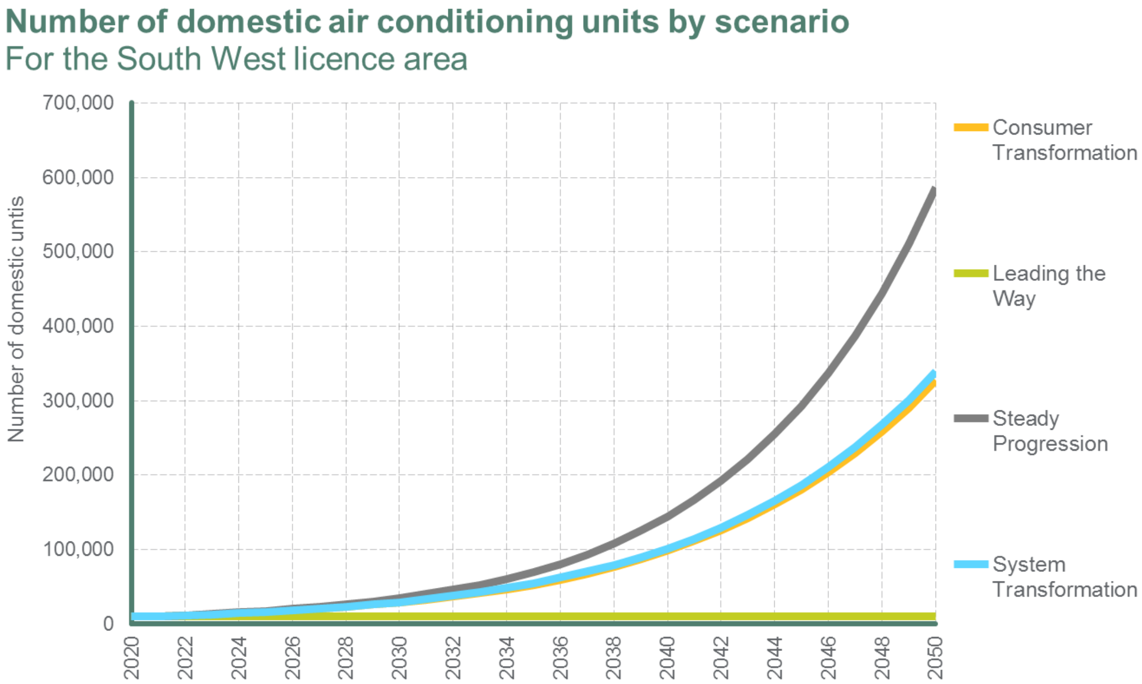
Near-term (April 2021 to March 2026)

- Near-term uptake of domestic air conditioning remains limited, reflecting the relative lack of demand for active cooling in the current climate.
- Domestic air conditioning is associated with high upfront and running costs, restricting uptake while it is seen as a luxury.

Medium and long-term (April 2026 to March 2050)

- The Future Homes Standard will dictate standards for new build homes. This is expected to include a stipulation that solar gain should be limited through passive measures such as shading, and that the dwelling should not be at risk of overheating. Importantly houses must comply with this standard even if active cooling is installed.
- As a result, all scenarios assume no air conditioning in new build homes.
- In existing homes, uptake of air conditioning accelerates in all scenarios.
  - Under **Steady Progression**, rising summer temperatures and societal reluctance to engage in passive cooling methods leads to exponential uptake of domestic air conditioning. This is seen as the 'easiest' route to comfortable internal temperatures. By 2050, 40% of current homes have an air conditioning unit in this scenario.
  - Under **Consumer Transformation** and **System Transformation**, uptake of domestic air conditioning accelerates, especially in urban 'heat island' areas. However, goals to reduce GHG emissions and electricity consumption limit uptake, with passive cooling measures encouraged and adopted. In these scenarios, 22-23% of homes in the South West licence area have an air conditioning unit by 2050.
  - Under **Leading the Way**, domestic air conditioning remains rare, with cooling requirements met through more sustainable methods such as shading, behaviour change, and higher levels of wider societal change. As a result, across the scenario timeframe (2021 to 2050), only around 1% of homes in the South West licence area have an air conditioning unit.

Figure 17



Reconciliation with National Grid FES 2021:

The FES 2021 does not directly detail numbers of domestic air conditioning units, and as such a direct comparison has not been completed. However, the FES 2021 does provide national-level data on annual domestic air conditioning demand by scenario, and an assumed consumption of 500 kWh/year for a typical domestic air conditioning unit. This allows for reconciliation at a high level:

- The South West licence area figures, in terms of proportion of homes with an air conditioning unit, are around three-quarters that of the FES in each scenario.
- This is based on analysis of:
  - Cooling degree days at 18.5 °C, where South West is slightly below the national average. This metric is used in every scenario.
  - Proportion of households in very dense urban areas, with the South West 42% below the national average. This metric is used in every scenario.
  - Proportion of households in fairly dense urban areas, with the South West 24% below the national average. This metric is used in every scenario except **Leading the Way**, which has minimal domestic air conditioning uptake.
  - Proportion of households in any form of urban area, with the South West 16% below the national average. This metric is used in **Steady Progression**, as air conditioning becomes common even outside of ‘heat island’ areas.
- As a result, the uptake of domestic air conditioning in the South West is projected to lag behind the national average in each scenario.

Factors that will affect deployment at a local level:

The spatial distribution of domestic air conditioning units has been based on:

- Affluence, given the high upfront and running costs of domestic units. This is weighted most strongly in the near term, where air conditioning is uncommon in all scenarios.
- Tenure, due to the greater likelihood of homeowners to invest in relatively expensive home improvements such as air conditioning, compared to tenants and landlords. As with affluence, this factor is weighted heavily in the near term where air conditioning uptake is more limited.
- Urban areas, as 'heat islands' are seen as key drivers in the uptake of domestic air conditioning. Urban areas also contain higher proportions of flats, which have a lower ratio of external surface area to floorspace, which prevents heat from escaping effectively at high temperatures.
    - Initial uptake of air conditioning is weighted towards the densest urban areas, where heat island effects are most prevalent.
    - Further uptake, especially under **Steady Progression** and the latter years of **Consumer Transformation** and **System Transformation**, is weighted across all urban areas.

Relevant assumptions from National Grid FES 2021:

Assumption number	3.1.2 - Uptake of Residential Air Conditioning
Steady Progression	Low willingness to change means society takes the easiest route to maintain comfort levels, therefore increased levels of air conditioning.
System Transformation	Medium uptake as society takes a mix of actions to maintain comfort levels (mix of air conditioning, tolerance of higher temperatures, changes to building design).
Consumer Transformation	Medium uptake as society takes a mix of actions to maintain comfort levels (mix of air conditioning, tolerance of higher temperatures, changes to building design).
Leading the Way	Low uptake as society changes to minimise uptake (e.g. personal tolerance of higher temperatures, changes to building design).

References:

National Grid ESO FES 2021 data, UK cooling degree days data, Census 2011, Future Homes Standard consultation documents

[2] Heat Networks, Energy Service Bristol
[3] The Ten Point Plan for a Green Industrial Revolution
[4] Future support for low carbon heat
[5] Clean Heat Grant: further policy design proposals
[6] English Housing Survey Energy Efficiency, 2018-19
[7] Heat networks pipeline
[8] Heat Networks Planning Database: quarterly extract
[9] Rethinking heat: a utility based approach for ground source heat pumps, Regen
[10] The Future Homes Standard: changes to Part L and Part F of the Building Regulations for new dwellings
[11] Opportunity areas for district heating networks in the UK
[12] Council action on climate change, Bristol City Council
[13] Fuel Poor Network Extension Scheme (FPNES) Governance Document
[14] Energy Company Obligation (ECO)
[15] How much we pay for connecting to the distribution electricity network is changing, Regen
[16] The role of hydrogen in Cornwall and the Isles of Scilly, Regen
[17] Value of the maritime sector, Maritime UK
[18] Bristol Hydrogen Boats
[19] Cornwall Marine Hydrogen Centre
[20] Undercover Zero
[21] Sustainable cooling POSTnote
[22] Air conditioning demand assessment, Tyndall Manchester
[23] World Air Conditioner Demand by Region

Results and assumptions

Generation technologies

Onshore wind in the South West licence area

Summary of modelling assumptions and results

Technology specification:

Onshore wind generation, including large-scale wind farms and smaller single-turbine sites.

Technology building blocks: Gen_BB015 – Onshore Wind >=1MW; Gen_BB016 – Onshore Wind <1MW.

Data summary for onshore wind in the South West licence area:

Installed capacity (MW)	Baseline	2025	2030	2035	2040	2045	2050
Steady Progression	338	343	390	421	435	470	492
System Transformation		343	389	444	538	612	670
Consumer Transformation		371	562	765	1,078	1,369	1,624
Leading the Way		349	504	655	911	1,137	1,334

Summary:

- The South West licence area has a long history of onshore wind development, hosting some of the first commercial wind farms in the UK. Over half of the baseline capacity, 174 MW, was connected in 2011 or earlier.
- The licence area's relatively high wind speeds and large areas of developable land have contributed to a baseline capacity of over 300 MW.
- A limited pipeline of new sites, due to difficulties in attaining planning permission for onshore wind developments in England, results in relatively low deployment in the near term.
- Proven resource availability and an assumed positive planning environment contribute to strong capacity growth in the medium and long-term under **Consumer Transformation** and **Leading the Way**.
- Under **Steady Progression**, lack of progress on decarbonisation results in limited deployment of onshore wind capacity, especially in England as planning policy remains obstructive.

Modelling assumptions and results:

Baseline

- There is a total of 338 MW of onshore wind capacity connected in the South West licence area.
- The majority of this capacity, 282 MW, comprises 35 large-scale wind farms of 1 MW or greater.
- There are 288 small-scale sites of less than 1 MW, totalling 56 MW of capacity, with many of these sites consisting of single, kilowatt-scale turbine installations.
- Just over half of the capacity in the licence area, totalling 174 MW, was first connected in 2011 or earlier. This includes some of the first onshore wind farms in the UK, such as Carland Cross Wind Farm, which has since been repowered in 2013.
- The vast majority of recent development occurred between 2012 and 2017 as a result of government subsidies such as the Feed-in Tariff. Over 150 MW of capacity was deployed in this timeframe.
- Since the end of 2017, less than 8 MW of onshore wind capacity has connected to the South West distribution network. This is primarily due to changes to the planning system in England, resulting in onshore wind being unlikely to attain planning permission in the vast majority of cases. Engagement with developers confirmed that Wales and Scotland were currently the focus of onshore wind development in GB.

Near-term (April 2021 to March 2028)

- There are seven pipeline sites with an accepted network connection offer, totalling 71 MW. The majority of this capacity comes from three sites of 20 MW each.
- Analysis of historic wind farm development timescales, crosschecked against engagement with developers, suggests that onshore wind farms typically take over four years to go from planning application submission to operation. This can include several years even after planning permission has been granted.
- As a result, with the majority of the pipeline sites not yet having attained planning permission, capacity growth begins to occur from 2024 to 2027, depending on the scenario. There is minimal deployment before 2024 in any scenario.
- Most South West stakeholders felt that onshore wind deployment would start picking up from 2027 onwards; however, a significant number felt that development could occur earlier, from 2024. This range of possible near-term outcomes is reflected in the scenarios:
    - Under **Consumer Transformation** and **Leading the Way**, it is assumed that all pipeline sites are built out, with the exception of one site that no longer appears to be in development.
    - Under **System Transformation** and **Steady Progression**, onshore wind development remains stagnant in England. In these scenarios, only a few small-scale projects with granted planning permission, or existing onshore wind farms looking to repower or extend, are developed in the near term.

Medium-term (April 2028 to March 2035)

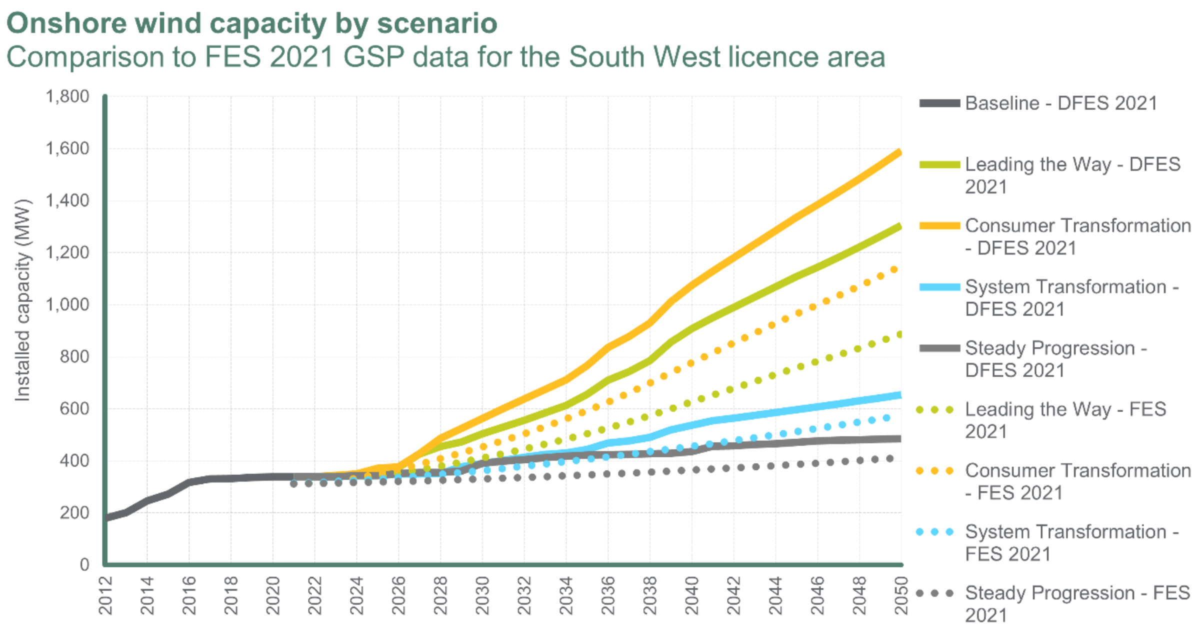
- As evidenced by the significant baseline, followed by a period of minimal deployment, onshore wind is particularly sensitive to changes to the planning regime. The planning environment, therefore, distinguishes the four scenario outcomes.
- Under **System Transformation** and **Steady Progression**, onshore wind continues to see very little deployment in the medium term, as a result of a continued lack of support in the planning system in England.
- Some capacity increase still occurs in these scenarios, mostly driven by repowering of older baseline sites with newer, higher-capacity turbines.
- Repowering projects at sites such as Carland Cross have shown that baseline sites can be repowered at much higher capacities using fewer turbines, as a result of the advances in onshore wind technology over the past decade.

- The **Consumer Transformation** and **Leading the Way** scenarios reflect a much more supportive planning regime for onshore wind in England, with onshore wind seen as a key component in reducing carbon emissions in the medium and long term.
- In these scenarios, the increased capacity is a result of both ambitious repowering of older baseline sites at increased capacities, and new projects developed in areas with developable wind resource.
- Feedback from developers suggests that while the inclusion of onshore wind support in the upcoming Contract for Difference auctions is positive, the highly competitive nature of these auctions means that most sites would be targeting a number of market opportunities, and could be developed without subsidy support. This is already occurring in Scotland.

Long-term (April 2035 to March 2050)

- The medium-term trends continue into the long term for each scenario, with new onshore wind capacity developed in **Consumer Transformation** and **Leading the Way**.
- **Consumer Transformation** sees particularly high levels of onshore wind development, with this scenario featuring greater amounts of distribution-scale renewable generation. This results in 1.6 GW of onshore wind capacity in the South West by 2050 under this scenario.
- In all scenarios, baseline sites developed during the Feed-in Tariff years of 2012 to 2017 are assumed to repower at the end of their operational life of 25-30 years.
- To reflect the range of repowering options, repowered capacity ranges from 150% in **Consumer Transformation** (where turbines are replaced by a similar number of newer, more efficient models), to 125% in **Steady Progression** (where sites are repowered with a reduced number of higher capacity turbines).

Figure 18



Reconciliation with National Grid FES 2021:

Results in this section relate to the FES 2021 data for the relevant GSPs within the South West licence area.

- The FES 2021 baseline (338 MW) for the South West licence area is broadly aligned with the DFES 2021 baseline (312 MW).
- In the near term, the DFES evaluates pipeline projects with an accepted connection agreement. This results in the DFES 2021 capacity being slightly higher than the FES 2021 in the near term. This is most evident in **Consumer Transformation** and **Leading the Way**.
- In addition to the pipeline, the DFES 2021 analysis assumes the repowering of legacy and existing baseline projects. This has a specific near-term impact in the South West from 2026 onwards, as it is a licence area that hosts some of the oldest onshore wind farms in the UK.
- Across the timeframe of the analysis, the DFES 2021 projections are substantially ahead of the FES 2021 GSP-level data, particularly in **Consumer Transformation** and **Leading the Way**. This is due to differences in how future development of onshore wind capacity has been assessed at a regional level.
- In the FES 2021: "Generation forecasts are apportioned according to the existing geographical distribution for all technologies except solar."[24] Due to the effective ban on new onshore wind capacity in England since 2017, the DFES analysis considers the existing distribution of onshore wind capacity skewed towards Wales and Scotland, and is not wholly reflective of resource availability.
- In the DFES 2021: A resource assessment of onshore wind resource has been utilised to guide medium-term and long-term projections. This results in higher levels of onshore wind capacity in English licence areas, such as the South West, due to the resource potential in the licence area relative to GB as a whole.

Factors that will affect deployment at a local level:

- The spatial distribution of new onshore wind sites in the near term is based on the location of pipeline sites, which show a similar distribution to the current baseline (along the northern parts of Cornwall and Devon, and around Avonmouth).
- In the medium and long-term, new capacity is distributed on the basis of:
  - Areas close to the existing electricity network, excluding areas that would hinder planning and siting of turbines, such as environmental designations (e.g. AONBs or National Parks), areas of housing or other buildings, and steep gradients.
  - Areas with developable wind resource, based on wind speed analysis
  - Analysis of historic planning permission records for each local authority.
- The modelled repowering of existing baseline sites naturally leads to further capacity on areas of the network that already host onshore wind.
- Local policies, identified by stakeholders, are included as positive weightings within the spatial distribution, for example:
  - The Cornwall Renewable Planning Guidance policies
  - Ambitious, accelerated net zero targets such as for Bristol
  - Policies D3 and D4 in the Sedgemoor District local plan.

Relevant assumptions from National Grid FES 2021:

Assumption number	4.1.3 - Wind generation (onshore)
Steady Progression	Slower pace of decarbonisation.
System Transformation	Focus on renewables but limited by societal preference for offshore turbines (less impact on land use and visibility)
Consumer Transformation	Strong support for onshore wind across all networks. Some of these projects may be in community ownership.
Leading the Way	High growth driven by the decarbonisation agenda and high demands from hydrogen production from electrolysis.

Stakeholder feedback overview:

Onshore wind	
Your comments to us	Our response
Stakeholders fed back that onshore wind deployment is most likely to pick up in late 2020s in England, though a number of stakeholders thought the early-mid 2020s would be possible.	In addition to direct engagement with wind developers, we have used stakeholder feedback from all four webinars to guide the pipeline and post-pipeline assessment of onshore wind projects. The four future energy scenarios used in the DFES have reflected the range of possible timescales identified by stakeholders.
The majority of stakeholders thought that most future onshore wind capacity will tend to be medium-scale, i.e. between 10 and 50 MW, rather than either larger transmission network scale projects or smaller <10 MW wind projects.	We have modelled the onshore wind deployment in the DFES scenarios on the assumption that a significant proportion will be medium-scale.
Consultation with developers confirmed our understanding that projects are likely to be developed without subsidy support, unless in specific circumstances where CfDs have been secured.	The viability of subsidy-free business models justifies the increase in onshore wind in two of the scenarios, where policy and planning environment is supportive of onshore wind in England.
Direct engagement with pipeline project developers suggested that onshore wind development in Wales and Scotland was the focus in the near-term, but that all resource would be investigated in the longer term, if the planning regime was supportive.	Onshore wind takes longer to pick-up in England under all scenarios, with most development occurring from the late-2020s onward. This aligns with both stakeholder feedback and direct developer engagement.

References:

WPD connection offer data, DNO Embedded Capacity Registers, National Grid ESO TEC register, the Renewable Energy Planning Database, Climate Emergency declaration data, Regen consultation with local stakeholders and discussion with developers, Regen questionnaire and consultation with local authorities.

Small-scale solar generation in the South West licence area

Summary of modelling assumptions and results

Technology specification:

Solar generation sites of installed capacity less than 1 MW. This includes domestic-scale rooftop PV (<10 kW) and small-scale commercial PV (10 kW – 1 MW), which could consist of rooftop installations such as on warehouses, or small ground-mounted arrays.

This relates to the following building block:

- Solar generation: Small (G98/G83) – Building block Gen_BB013

Data summary for small-scale solar PV in the South West licence area:

Installed capacity (MW)	Baseline	2025	2030	2035	2040	2045	2050
Steady Progression	433	451	520	609	697	786	876
System Transformation		507	723	969	1,212	1,454	1,696
Consumer Transformation		616	1,076	1,574	2,073	2,585	3,099
Leading the Way		619	1,091	1,608	2,129	2,665	3,204

Summary:

- The South West licence area saw particularly high levels of small-scale solar deployment during the 2010s, as a result of the Feed-in Tariff support scheme.
- While deployment has stagnated over the last few years, a combination of falling installation costs, uptake of electric vehicles and an increasing requirement for renewable generation leads to renewed uptake of small-scale solar in all scenarios.
- By 2050, small-scale solar uptake reaches over seven times today's levels under **Consumer Transformation** and **Leading the Way**, and four times today's levels under **System Transformation**.
- For domestic-scale rooftop solar, under **Consumer Transformation** and **Leading the Way** this would equate to c. 35-40% of homes hosting an average-sized rooftop PV array. However, decreasing installation costs and improvements in panel efficiency are likely to increase average domestic rooftop PV capacities in the future. As such, the true proportion is likely to be slightly lower.

Modelling assumptions and results:

Baseline

- The South West licence area currently has c. 75,000 grid-connected domestic-scale solar PV installations, representing over 5% of homes, the highest in WPD's four licence areas. This totals 243 MW, at an average of 3.3 kW per array.
- In addition, there are currently over 3,000 small-scale commercial solar PV sites, totalling 191 MW at an average of 64 kW per array.
- Almost all baseline solar PV was installed through the support of the Feed-in Tariff scheme, which ran from 2010 to 2019.
- The vast majority of historic development occurred between 2010 and 2015, when tariff payments were highest. Over 393 MW of capacity, 90% of the baseline, was deployed in the South West licence area in these five years.
- Since the start of 2016, less than 50 MW of small-scale solar PV capacity has connected to the South West distribution network, following a reduction in the subsidy rate and subsequent closure of the Feed-in Tariff in 2019.
- The Smart Export Guarantee[25], launched in January 2020, provides revenue for small-scale low carbon generation exported to the grid, such as rooftop solar. However, rates are currently not lucrative enough to drive significant deployment.
- Additionally, the costs of rooftop solar installations have risen in the past year. This has been attributed to factors such as increased material costs and the Covid-19 pandemic.
- The small-scale solar baseline is marginally lower than the WPD DFES 2020 baseline. This is due to updated modelling excluding off-grid installations that do not interact with the distribution network.

Near-term (April 2021 to March 2024)

- There is minimal deployment in the early 2020s due to the challenging financial case for small-scale solar.
- There is a pipeline of 56 commercial solar sites, totalling 6 MW, which have accepted a grid connection offer, which are projected to connect between 2021 and 2024 in all net zero scenarios.
- Previous stakeholder engagement suggested that rooftop solar PV deployment on new-build housing is between 5%-10%. This range is reflected in the near-term projections across the scenarios.

Medium-term (April 2024 to March 2035)

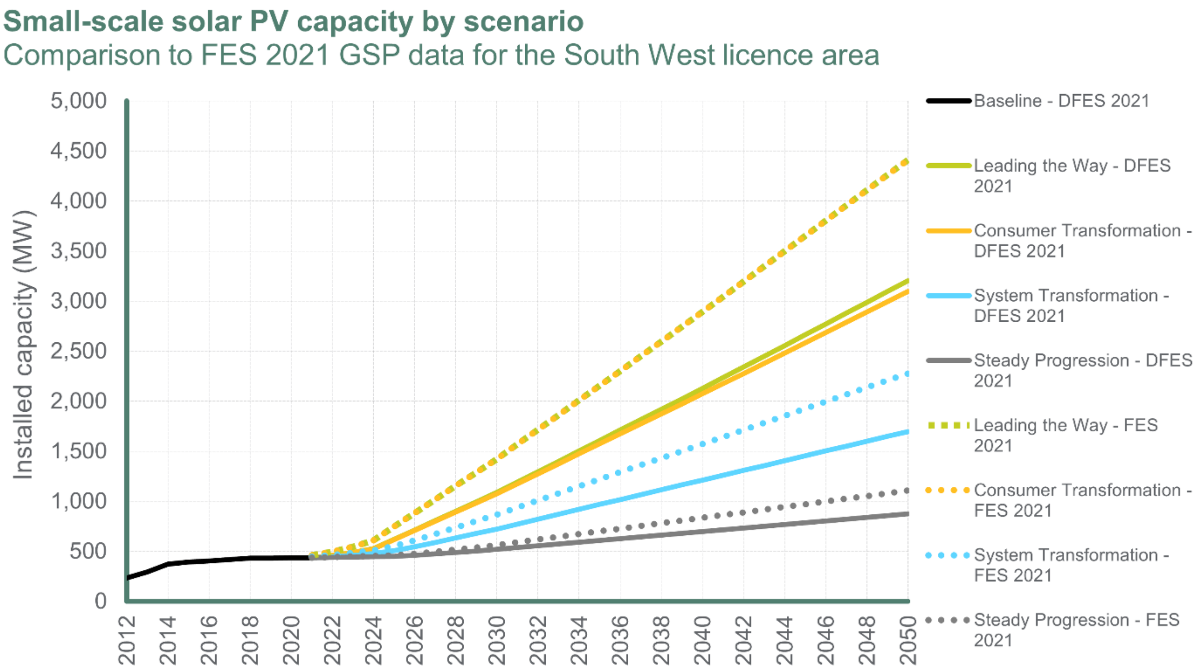
- Small-scale solar PV uptake accelerates from the mid-2020s in all scenarios. This is due to a combination of falling installation costs, and opportunities to increase self-consumption (such as through smart electric vehicle charging).
- Rooftop solar on new-build housing and commercial space is modelled to become more popular, especially under the net zero scenarios. This reflects falling costs, increased standards for new-build properties, and increasing green ambition from consumers.
- Under **Consumer Transformation** and **Leading the Way**, this is augmented by high levels of consumer engagement in smart electricity usage, Time of Use Tariffs, and green ambition.
  - This results in over 1.5 GW of small-scale solar PV connected in the South West licence area by 2035, under these scenarios.
- In contrast, just 0.6 GW of small-scale solar is connected by 2035 under **Steady Progression**. This reflects lower uptake of low carbon technologies, smart tariffs, and less engaged consumers.

Long-term (April 2035 to March 2050)

- The trends established in the medium-term continue out to 2050.

- The uptake of small-scale solar PV is more than seven times the baseline under **Consumer Transformation** and **Leading the Way**, with small-scale solar forming a key part of reaching net zero in these scenarios. This represents rooftop solar PV on around a third of dwellings if installations remain at around 3 kW on average.

Figure 19



Reconciliation with National Grid FES 2021:

Results in this section relate to the FES 2021 data for the relevant GSPs within the South West licence area.

- The FES 2021 and WPD DFES 2021 baselines align, with just less than 500 MW of capacity currently installed in the South West licence area.
- However, projections of small-scale solar PV in the WPD DFES 2021 are consistently behind the FES 2021 projections at a GSP level.
- The DFES 2021 projections are based predominantly on underlying building stock and demographic factors, derived from stakeholder engagement and market insight.
    - The South West licence area has slightly lower than average levels of affluence (20.9% in social grade A/B[26], compared to 22.7% in GB) and social housing (13.5%, compared to 18.2% in GB) which have been identified as key uptake factors.
    - However, levels of home ownership and detached/semi-detached dwellings in the licence area, which are also a significant uptake factors, are higher than the national average (66.7% and 55.2%, compared to 63.4% and 53.1% in GB respectively).
- These competing factors result in minimal net impact in the modelling. As a result, the DFES 2021 projections are broadly proportional to the number of homes in the licence area, which represents around 5% of GB homes.
- Conversely, the South West hosts over 9% of the national small-scale solar PV baseline. This could be a factor in the FES 2021 projections being significantly higher than the DFES 2021 projections, however this is not definitively clear.

Factors that will affect deployment at a local level:

- The spatial distribution of new small-scale solar PV in the South West licence area has been divided into domestic-scale (<10 kW) and commercial-scale (10 kW – 1 MW) solar PV.
- Domestic uptake is dictated by key factors, including tenure, EV ownership, affluence and building type. These factors, and the weighting thereof, were informed through engagement with local and regional stakeholders.
- In the near-term, uptake is weighted towards home ownership, EV ownership and affluence. In the longer term, uptake becomes more prevalent across all affluence levels, especially in **Leading the Way** and **Consumer Transformation**.
- New build housing is also a key influencer of local deployment. New housing developments are modelled specifically based on local planning data.

Relevant assumptions from National Grid FES 2021:

Assumption number	4.1.5 - Solar generation (plant smaller than 1MW)
Steady Progression	Slower pace of decarbonisation.
System Transformation	Transition to net zero results in strong growth in small solar. Supports production of hydrogen by electrolysis.
Consumer Transformation	Very high growth in small solar as it supports the transition to net zero and is highly aligned to the high societal change.
Leading the Way	Very high growth in small solar as it supports the transition to net zero and is highly aligned to the high societal change.

Stakeholder feedback overview:

Small-scale solar PV	
Your comments to us	Our response
Stakeholders identified home ownership, EV ownership and affluence as the key factors in rooftop solar installation in the near term.	We have weighted the distribution of rooftop solar capacity more towards these factors in the near-term years of the analysis.
Stakeholders noted that rooftop solar uptake is often influenced by planning regulations, especially in areas such as conservation zones.	Where possible, we have reflected conservation zones and other protected areas in the geographical distribution of rooftop solar PV and other domestic-scale technologies.
Stakeholders noted the potential for commercial rooftop PV to be deployed on more large commercial and industrial buildings such as warehouses.	When projecting the future distribution of rooftop PV across a licence area, our small-scale commercial PV modelling has considered the amount of various property types, including warehousing and sheds.

Stakeholders asked whether the potential reducing cost of domestic batteries in the future influences the uptake of domestic rooftop PV in our modelling.	The scenario framework assumes varying levels of complementary technology advancement and cost reduction of low carbon technologies. These work in tandem, with the scenarios with higher levels of low carbon technologies also featuring higher levels of rooftop PV. The modelling of domestic battery uptake is directly informed by the small-scale solar PV projections in the DFES.

References:

WPD connection offer data, Feed-in Tariff registers, BEIS solar photovoltaics deployment data, Climate Emergency declaration data, Regen consultation with local stakeholders and discussion with developers, Regen questionnaire and consultation with local authorities.

Large-scale solar generation in the South West licence area

Summary of modelling assumptions and results

Technology specification:

Solar generation sites of installed capacity of 1 MW and above. This relates to the following building block:

- Solar generation: Large (G99) – Building block Gen_BB012

Data summary for large-scale solar PV in the South West licence area:

Installed capacity (MW)	Baseline	2025	2030	2035	2040	2045	2050
Steady Progression	1,080	1,152	1,297	1,666	1,799	1,929	2,058
System Transformation		1,177	1,571	2,235	2,678	2,966	3,290
Consumer Transformation		1,177	1,572	2,236	2,679	2,967	3,290
Leading the Way		1,317	2,123	2,961	3,753	4,160	4,206

Summary:

- The South West has historically been a hotspot for large-scale solar PV deployment, with over 1 GW of capacity connected over the past decade.
- There is a reasonable pipeline of new projects in various stages of planning. However, despite some of the best solar resource in the country, developers appear to be turning attention to other areas of the country, such as the Midlands.
- The South West is likely to see continued development of solar PV throughout the coming decades to 2050. Solar PV already represents one of the cheapest forms of renewable electricity available, and is expected to further reduce in cost.
- Current business models are based around standalone solar farms, or pairing with co-located battery storage. In the future, solar PV could also potentially be co-located with hydrogen electrolysis.
- Under the four future energy scenarios, large-scale solar PV capacity in 2050 ranges from 1.9 GW under **Steady Progression**, around double existing capacity, to over 4 GW under **Leading the Way**, an almost four-fold increase in existing capacity.

Modelling assumptions and results:

Baseline

- There is a total of 1,080 MW of large-scale solar PV capacity connected in the South West licence area, across 225 sites averaging 4.8 MW.
    - The vast majority of this capacity is attributed to relatively small solar farms (1 MW to 10 MW), totalling 921 MW across 214 sites.
    - The largest baseline site, Canworthy Solar Farm in Cornwall, has an installed capacity of 32.8 MW. This is the only site in the baseline larger than 20 MW.
- The vast majority of historic development occurred as a result of the FiT scheme, which supported up to 5 MW of solar PV capacity through tariff payments for generated electricity.
    - Over 830 MW of capacity was deployed between 2012 and 2015, at the height of FiT-supported solar development in the South West.
    - Since the start of 2017, with the tapering and eventual closure of the FiT scheme combined with network congestion, only 21 MW of large-scale solar PV capacity has connected to the South West distribution network.

Near-term (April 2021 to March 2028)

Pipeline

- There are 42 pipeline sites with an accepted network connection offer, totalling 962 MW, with an average capacity of 23 MW. This is almost five times bigger than a typical baseline site.
- Over half the pipeline capacity, totalling 549 MW, comes from 12 sites of 35 MW capacity or greater.
- Analysis of historic solar farm development timescales, crosschecked against engagement with developers, suggests that solar farms typically take just a few months to attain planning permission. After being granted planning permission, solar farms typically become operational in less than 12 months.
- Every project in the pipeline was researched to ascertain the current planning status. This, alongside the length of time since the connection offer was accepted and the scale of the project, was used to determine when the project goes ahead in each scenario. This was supported by direct engagement with project developers.
- The pipeline consists of projects across all stages of development, from imminent construction to not yet having entered the planning system:

Under construction	22 MW across 4 sites
Granted planning permission	77 MW across 4 sites
Planning application submitted	121 MW across 3 sites
In pre-planning, with evidence of developments such as seeking a screening opinion from the local planning authority, or conducting a public consultation	222 MW across 7 sites
No evidence found through desk research. These sites are assumed to mainly be in the early stages of pre-planning development.	444 MW across 20 sites
Rejected or withdrawn in planning, or abandoned by the developer	77 MW across 4 sites

- Under **Leading the Way**, it is assumed that all pipeline sites are built out, with the exception of sites that have been rejected in or withdrawn from planning, or abandoned.

- This results in projects with planning permission, in planning, or in advanced stages of pre-planning, connecting before 2028. This represents around half of the pipeline, totalling 442 MW.
- Under **Consumer Transformation**, **System Transformation** and **Steady Progression**, only sites that have progressed to submission of a planning application, or have already attained planning permission, have been reflected directly in the modelling.
  - This is key to ensuring that the future energy scenarios for large-scale solar PV reflect not just current headroom on the distribution network, but also where solar developers may look to deploy capacity in the future.
  - Under **Consumer Transformation** and **System Transformation**, this results in 255 MW of new large-scale solar PV capacity being built between 2022 and 2028.
  - Under **Steady Progression**, this results in 99 MW of new large-scale solar PV capacity in this timeframe.
- Most South West stakeholders felt that large-scale solar PV deployment would start picking up from 2025 onwards. However, a significant number felt that development could occur earlier, from 2023. This range of possible near-term outcomes is reflected in the scenarios.

Business models

- There are a number of near-term uncertainties that may make or break emerging solar PV business models. The size of the pipeline, in terms of capacity, reflects the upper range of potentially rapid solar farm development in the near-term. However, the stagnation over recent years could linger in some conditions. Key near-term aspects considered are:
  - **Engineering, procurement and construction** (EPC) costs for utility-scale solar farms. These costs have trended rapidly downwards over recent years, enabling merchant solar PV to become more viable. However, the trend has been bucked in 2021, with increasing prices of raw materials for solar modules increasing EPC costs for the first time in many years.
  - **Routes to market** for new solar farms. While there are various routes to market being explored, including corporate power purchase agreements (PPAs), private wires and potential Contract for Difference (CfD) auctions, merchant business models appear to be the intended route to market for the majority of pipeline solar PV capacity.
  - **Economies of scale.** As evidenced by the pipeline, the most viable merchant solar projects are large-scale, sometimes upwards of 50 MW, taking advantage of economies of scale to drive down the levelised costs of electricity produced. As a result, in the pipeline analysis, it has been assumed that larger projects progress sooner, including through planning. This is reflected in the analysis of pipeline projects, with larger-scale projects typically being further through the planning process than similarly aged smaller projects.
  - **Co-located solar and battery storage** features in a significant number of pipeline projects, providing an element of risk-sharing against merchant solar risk and opening up energy storage revenue streams for the project.
  - **The impact of Ofgem's minded-to decision on the Significant Charging Review**, which if implemented from April 2023 as proposed, would likely result in reduced network charges for assets connecting to the distribution network, such as large-scale solar generation. This could result in a tipping point for project viability in some cases.

Medium-term (April 2028 to March 2035)

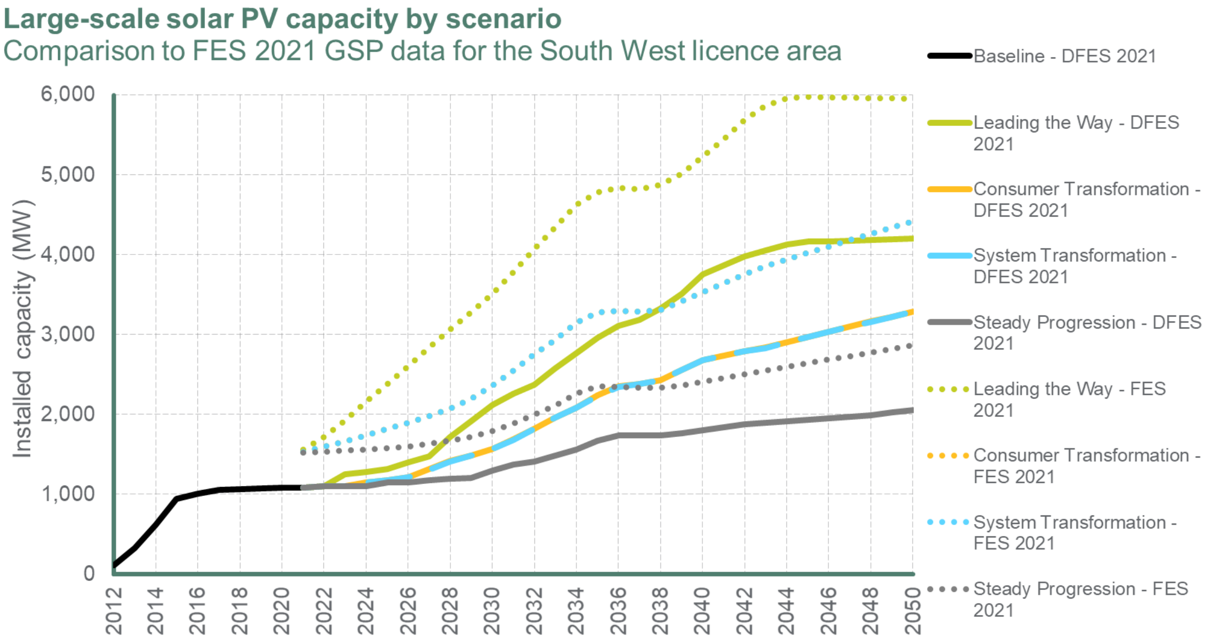
- The capacity of solar PV deployed in each scenario, and the distribution of this new capacity, varies significantly by scenario.
- Future solar capacity in the licence area has been modelled using a resource assessment, reflecting criteria used by developers to locate suitable sites for large-scale solar PV deployment. This includes, but is not limited to:

- Land that is proximal to the existing distribution network, based on analysis of existing sites to determine maximum viable connection cable distances.
    - Land that is flat or with a south-facing aspect.
    - Agricultural land grades, focussing on lower value Grade 3-5 agricultural land
    - Exclusion of built-up areas
    - Exclusion of protected areas, such as National Parks and AONBs.
    - Exclusion of flood zones
    - Levels of solar irradiance.
- Under **Leading the Way**, less advanced pipeline projects (namely projects that have not yet applied for planning permission) are modelled to connect throughout the late 2020s and early 2030s.
    - This results in a total of almost 3 GW of large-scale solar PV capacity connected by 2035 under this scenario.
- Under **System Transformation** and **Consumer Transformation**, deployment of large-scale solar PV continues at the rate seen in the near-term.
    - This results in a total of c. 2.2 GW of large-scale solar PV capacity connected by 2035 under this scenario.
- Under **Steady Progression**, while deployment of large-scale solar PV is limited, the South West licence area hosts c. 1.7 GW of capacity by 2035.

Long-term (April 2035 to March 2050)

- Large-scale solar PV continues to be deployed in the long term, as one of the cheapest forms of low carbon electricity generation.
- At very high levels of solar deployment, seen under **Leading the Way** in the long term, self-cannibalisation could threaten the capture prices of solar PV generation.
    - This is where high levels of simultaneous generation by solar PV, especially on sunny summer days when demand is low and generation is high, leads to oversupply of electricity and low or even negative electricity prices.
    - This contributes to a deceleration of solar deployment from the mid-2040s onwards in this scenario.
- However, the threat of self-cannibalisation is mitigated by:
    - Co-location with electricity storage to defer exports to more profitable times of peak demand.
    - Potential co-location with hydrogen electrolysis to convert low value solar PV output into high value green hydrogen.
    - Demand increasing to match periods of high renewable generation, such as through smart EV chargers, smart appliances, and Time of Use Tariffs.
- Additionally, repowering of solar farms at the end of their operational life could result in an increase in solar PV capacity at existing baseline sites in the three net zero scenarios.
    - Current solar modules have around twice the power density (in terms of Watts per square meter), as modules deployed during the 2010s. Existing sites could therefore be repowered to higher capacities, and higher capacity factors, without changing the site layout or number of panels, simply through replacement with higher efficiency modules.
    - However, it could be more profitable to simply extend the life of baseline sites, rather than incur the capital costs of replacing the solar modules.
- As a result, a range of outcomes has been modelled, ranging from repowering at 150% capacity under **Leading the Way** to no capacity increase under **Steady Progression**.
- By 2050, large-scale solar PV capacity reaches over 4 GW under **Leading the Way**, approximately four times the baseline capacity. This compares to only 2 GW under **Steady Progression**, around double the baseline capacity.

Figure 20



Reconciliation with National Grid FES 2021:

Results in this section relate to the FES 2021 data for the relevant GSPs within the South West licence area.

- The FES 2021 baseline for the South West licence area is significantly higher than the DFES 2021 baseline (by around 50%). The reason for this discrepancy is unclear. Previously, the DFES and FES baselines were consistent, totalling around 1,000 MW in capacity.
- In the near term, the DFES evaluates pipeline projects with an accepted connection agreement. This results in the DFES 2021 uptake being slower than the FES 2021 in the near term, as there are a relatively low number of projects in advanced stages of planning in the South West licence area, compared to the other WPD licence areas such as the East Midlands.
- Across the timeframe of the analysis, the DFES 2021 projections are consistently around one-third lower that the FES 2021 GSP-level data, reflecting the baseline discrepancy. This is despite similarities in how future development of large-scale solar PV capacity has been assessed at a regional level, specifically:
  - In the FES 2021: “Our solar spatial forecast is designed to reflect the fact that as solar installed capacity increases it will spread more evenly across the country. Today solar is most prevalent in the South and East of England.”
  - In the DFES 2021: A resource assessment of large-scale solar PV resource has been utilised to guide medium-term and long-term projections. This reflects land with good potential for solar PV deployment, with a relatively minor weighting towards areas with higher irradiance in the south of GB.

Factors that will affect deployment at a local level:

- Near-term distribution of new solar PV capacity is dictated by the exact location of pipeline sites.
- Beyond the pipeline of accepted connections, new large-scale solar PV capacity is distributed based on Regen’s large-scale solar PV resource assessment. This considers irradiance, designated land areas, physical constraints, network proximity, ground slope and aspect.

- Modelled repowering of solar farms in the longer-term results in new capacity at existing baseline sites.
- Each local authority's planning history is assessed to augment the solar resource assessment. Local policies, identified by stakeholders, are also included as positive weightings within the spatial distribution, for example:
    - The Cornwall Renewable Planning Guidance policies
    - Ambitious, accelerated net zero targets such as for Bristol
    - Climate emergency declarations.

Relevant assumptions from National Grid FES 2021:

Assumption number	4.2.15 – Solar generation (plant greater than 1 MW)
Steady Progression	Slower pace of decarbonisation.
System Transformation	Transition to net zero results in strong growth in large solar.
Consumer Transformation	Transition to net zero results in strong growth in large solar.
Leading the Way	Very high ambition to decarbonise drives a focus on technologies that are low carbon. Supports production of hydrogen by electrolysis.

Stakeholder feedback overview:

Large-scale solar PV	
Your comments to us	Our response
The majority of stakeholders thought the pipeline of new solar projects would begin connecting within the next 3-5 years, but some responses suggested the later 2020s.	After confirmation with solar developers, we have used the engagement from all four webinars to guide the logic and assumptions we have applied to assessing the pipeline of solar PV projects. The four future energy scenarios should broadly reflect the range of possible timescales identified by stakeholders.
When asked why the solar PV pipeline was particularly large in the Midlands, rather than the South West where development has historically been focussed, stakeholders identified the proximity to energy demand and lower cost of land as the likely drivers.	We have considered these aspects as major distribution factors in the modelling. The distribution of solar PV uses Regen's in-house solar resource assessment, which accounts for these (and various other) factors. The weighting of irradiance in the solar resource assessment is now minimal.

References:

WPD connection offer data, DNO Embedded Capacity Registers, National Grid ESO TEC register, the Renewable Energy Planning Database, Climate Emergency declaration data, Regen consultation with local stakeholders and discussion with developers, Regen questionnaire and consultation with local authorities.

Hydropower in the South West licence area

Summary of modelling assumptions and results

Technology specification:

This analysis covers any hydropower generation connecting to the distribution network in the South West licence area, excluding pumped hydro storage. Includes a comparison to FES 2021 data, as reported for Building Block ID number Gen_BB018.

Data summary for hydropower in the South West licence area:

Installed capacity (MW)	Baseline	2025	2030	2035	2040	2045	2050
Steady Progression	9	9	9	10	10	10	10
System Transformation		9	10	10	11	11	11
Consumer Transformation		10	11	12	13	14	15
Leading the Way		10	10	10	11	11	11

Summary:

- The South West licence area saw early deployment of hydropower sites, with sites being installed since the 1930s at reservoirs in Dartmoor. There was a rise in capacity again in the 2010s with the introduction of the Feed-in-Tariff.
- Only one new 360 kW hydropower site, in South Gloucestershire, has been given a connection agreement, so deployment in the near term is likely to be low in all scenarios.
- Under a **Consumer Transformation** scenario, an additional 5.5 MW is expected to be installed by 2050, a 58% increase on current installed capacity.

Modelling assumptions and results:

Baseline (up to 31st March 2021)

- There is 9.4 MW of installed hydropower capacity operational in the South West licence area. There are three sites over 1 MW: 2.6 MW at Mary Tavy, 1.9 MW at Okehampton Roadford reservoir, and 1.8 MW at Plymouth Derriford waterworks.
- Many reservoirs, particularly on Dartmoor, have hydropower installed and at a larger capacity than typical run-of-the-river hydropower schemes.
- The WPD connection data has been supplemented with 43 sites identified that are accredited under the FiT and ROC schemes, totalling 3.1 MW.

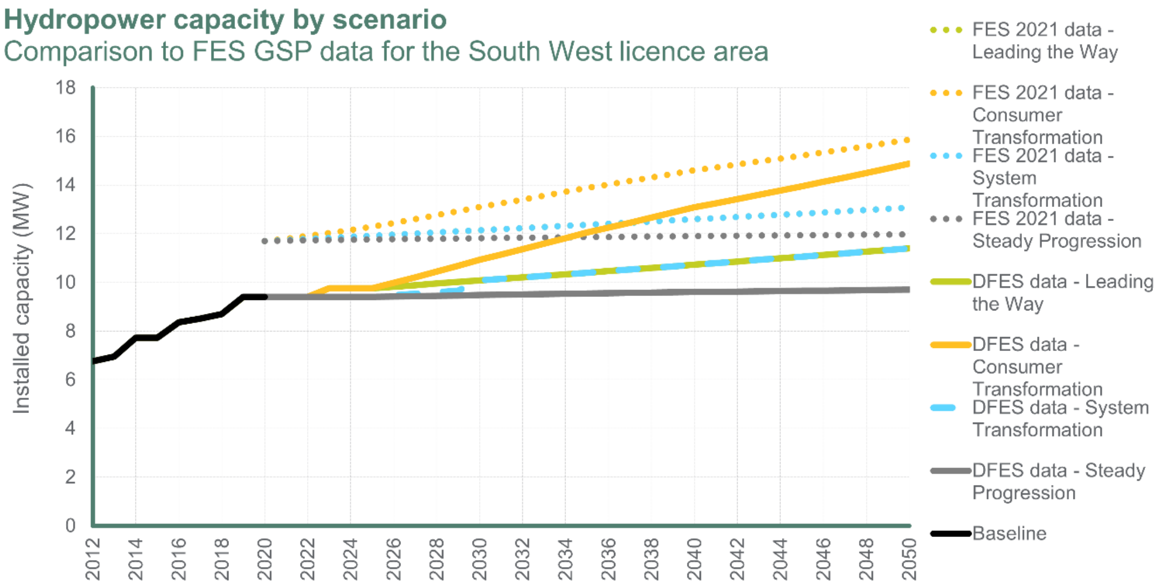
Near term (April 2021 – March 2025)

- There is a 360 kW site in South Gloucestershire with an accepted connection agreement.
- This is expected to connect in 2023 under **Consumer Transformation** and **Leading the Way**. This project is modelled to connect later in **System Transformation**.
- There is also potential for a community energy site in Bristol which is at an early stage of development and has received funding from the European Regional Development Fund but does not have a connection agreement.

Medium and long term (April 2025 – March 2050)

- The deployment of hydropower capacity in the South West licence area is expected to be limited in all scenarios out to 2050, with most capacity comprising small-scale developments connecting in the net zero scenarios.
- Significant additional capacity is only seen under **Consumer Transformation**, with an additional 5.5 MW of capacity connecting by 2050. **System Transformation** and **Leading the Way** have 2 MW of additional capacity connecting by 2050.
- The civil infrastructure installed for existing sites tends to be long lasting, meaning that sites can be expected to repower when the machinery reaches the end of its useable life. Where sites need to repower, it has been assumed that they repower at the same capacity: as a mature technology, hydropower has limited cost reduction potential.
- Sites are likely to be limited to onsite generation, private wire connections or through developments where wider objectives override the need for return on investment, for example sites with a link to tourism, heritage, or corporate sustainability objectives.

Figure 21



Reconciliation with National Grid FES 2021:

Results in this section relate to the FES 2021 data as reported for Building Block ID number Gen_BB018.

- The current installed capacity of hydropower in the South West licence area is slightly lower in the WPD DFES 2021 data than in the FES 2021. Further work is needed to understand the differences in data for small-scale generation at a licence area level.
- The WPD DFES 2021 projections in the near term are below those in FES 2021 under all scenarios, reflecting the lack of pipeline and feedback from industry consultation regarding the challenging business case for new hydropower projects.
- In the long term, WPD DFES 2021 capacity under **Consumer Transformation** is higher than FES 2021 due to analysis of potential resource availability in the licence area.
- New large-scale hydropower schemes in the South West are unlikely due to a lack of viable site locations.

Factors that will affect deployment at a local level:

- The distribution of new hydropower capacity is based on the indicative location of rivers, dams and reservoirs that could potentially host a hydropower site, as well as the pipeline site in South Gloucestershire.
- The analysis considers the maximum head and thus the potential power capacity of bodies of water across England and Wales.

Relevant assumptions from the National Grid FES 2021:

Assumption number	4.1.2 - Other renewables including marine and hydro generation
Steady Progression	Low support and therefore other renewables cannot compete with low cost solar and wind generation.
System Transformation	Support for large scale renewable technologies (i.e., tidal marine).
Consumer Transformation	Potential for many small-scale projects that will have larger societal impact coupled with support for marine technologies across all scales.
Leading the Way	Focus on rapid decarbonisation results in prioritising renewables that are available at lowest cost today (i.e., solar and wind). Innovation in other flexible solutions results in less need for a wide range of renewables.

References:

WPD connection offer data, the Feed-in-Tariff database, Renewable Obligations Certificates database, the Environment Agency, the Renewable Energy Planning Database, Regen consultation with local stakeholders and discussion with developers.

Geothermal power in the South West licence area

Summary of modelling assumptions and results

Technology specification:

This analysis covers all geothermal power generation sites connecting to the distribution network, which could be used in conjunction with low-carbon heat generation. It includes a comparison to FES 2021 data, as reported for Building Block ID number Gen_BB019.

Data summary for geothermal power in the South West licence area:

Installed capacity (MW)	Baseline	2025	2030	2035	2040	2045	2050
Steady Progression	3	3	5	5	5	5	5
System Transformation		3	5	12	12	12	12
Consumer Transformation		7	17	27	27	27	27
Leading the Way		7	27	37	42	47	47

Summary:

- The South West has significant geothermal resource that could provide heat and power.
- As a technology, geothermal power is challenging and often faces poor funding, long lead times, lengthy permitting processes, and high costs, as well as an increasing scarcity of exploitable sites[27].
- Future capacity will depend on the success of the pioneering developments at the Eden Project and the United Downs geothermal power project, both in Cornwall.
- The technology is currently experiencing a high level of interest from investors, partly driven by the prospect of low carbon lithium extraction, which has recently been discovered at the United Downs geothermal site[28]. If trials can successfully extract lithium from geothermal waters, there could be a significant increase in geothermal capacity, particularly in Cornwall. However, it is uncertain whether generated power would be exported to the grid, or instead used on-site to drive lithium extraction, recovery and processing.

Modelling assumptions and results:

Baseline (up to 31st March 2021)

- The United Downs[29] site, a joint venture between Geothermal Engineering Ltd. and Thrive Renewable, has been commissioned, having undertaken final testing over summer 2020. It is now connected with a capacity of 3.2 MW, although it is not expected to generate electricity until 2022.

Near term (April 2021 – March 2025)

- The Eden Project in Cornwall is aiming to develop a 3-4 MW geothermal electricity power generation site. However, the potential power capacity of geothermal sites can be uncertain before full drilling operations are completed. The purpose of this development is to heat and power the tourist site, and to export power onto the distribution network.
- Drilling began in May 2021, and depending on its success, this site could connect as early as 2023 in a **Consumer Transformation** or **Leading the Way** scenario. This site is expected to connect in all scenarios but is projected to be delayed and connect at a lower capacity in **System Transformation** and **Steady Progression**.

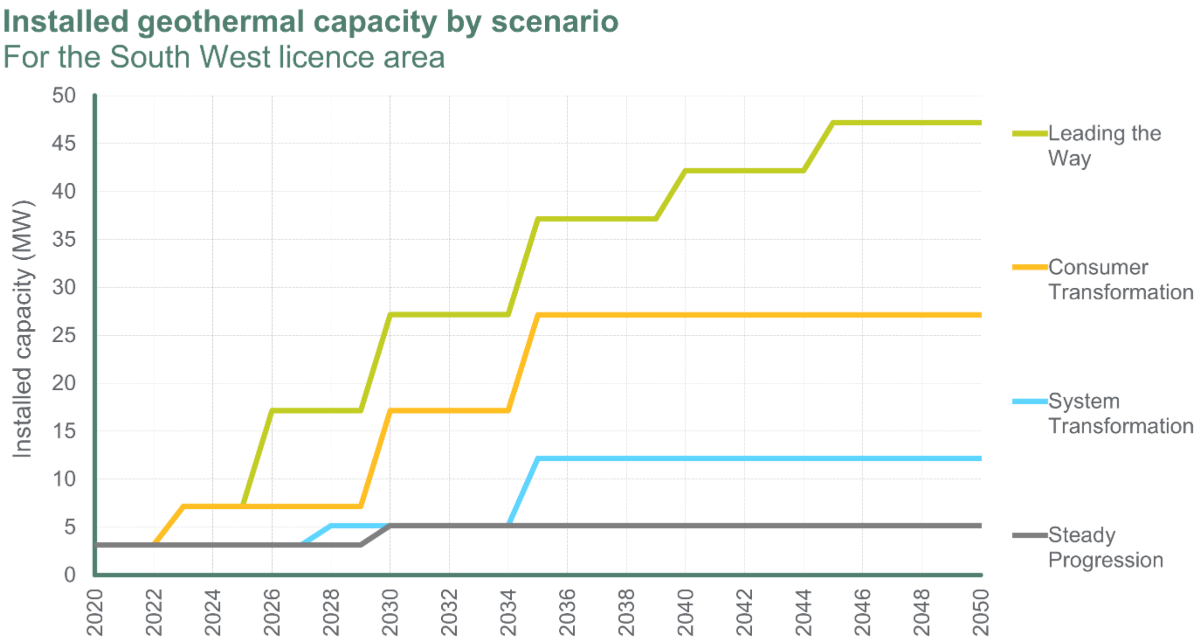
Medium term (April 2025 – March 2035)

- Geothermal Engineering Ltd., the leading geothermal developer in the South West, has announced plans for four new geothermal plants in Cornwall, each with a capacity of 5 MW[30]. If planning applications and local consultations are approved, they expect the sites to connect by 2026.
- It has been assumed that under **Consumer Transformation** and **Leading the Way** each new site will have the full 5 MW capacity.
- Due to the early stages of development and lack of a connection agreement, only two of these projects (10 MW) are modelled to connect by 2026 under **Leading the Way** and **Consumer Transformation**. The remaining two sites (10 MW) are modelled to connect in 2030 in these scenarios.
- Under **System Transformation**, the sites are assumed to be developed at a lower power capacity, similar to what is already being demonstrated at the United Downs baseline site in Redruth (3.6 MW). Deployment is expected to be delayed and reduced overall, reflecting the focus on large-scale transmission projects in this scenario.
- If the existing baseline and near-term pipeline projects are found to be costly or inefficient to deploy, there is likely to be limited further development. No new capacity is projected in the **Steady Progression** scenario, representing this uncertainty.

Long term (April 2035 – March 2050)

- Geothermal Engineering Ltd. have ambitious plans for geothermal energy, with a target to produce "in excess of 500 MW of power from geothermal resources'[30] across the UK in the next 20 years. Cornwall is recognised as the best place to exploit the UK's deep geothermal resources[31]. This potential and an assessment of what could potentially connect to the distribution network has therefore been reflected under **Leading the Way**, with an additional 20 MW of capacity connecting across Cornwall between 2035 and 2050.

Figure 22



Reconciliation with National Grid FES 2021:

There is no distribution connected geothermal capacity in the FES 2021 Building Block ID number Gen_BB019 in the WPD licence areas.

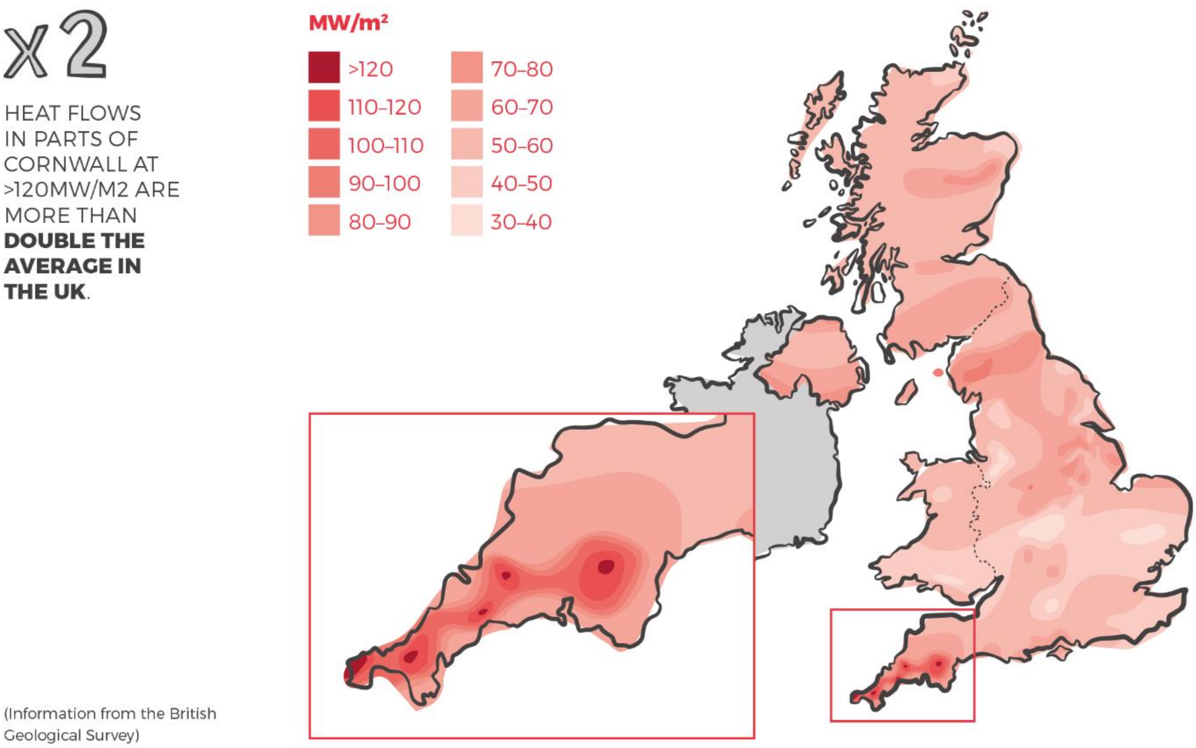
- As there is no capacity projected in FES 2021 for geothermal power generation in this licence area, no direct comparison is made to FES 2021 results.
- A significant potential increase in capacity has been modelled in the WPD DFES 2021 under **Leading the Way** and **Consumer Transformation**. The reasons for this are:
    - Known sites, both operational and under construction
    - Discussion with developers and wider industry about potential pipeline sites
    - Geothermal resource in the South West licence area
- There is significant range across the WPD DFES 2021 scenario projections, reflecting the uncertainty whether the pilot projects at United Downs and the Eden Project will spark wider deployment in the region.

Factors that will affect deployment at a local level:

- The location of geothermal power sites is highly dependent on geology and is therefore assumed to only be developed in Cornwall, where there is granite bedrock[32]. The location of the United Downs pilot project was chosen for the available heat resource, as well as the proximity to the electricity network, road access and potential heat customers[32].
- The four proposed Geothermal Engineering Ltd. Sites in Cornwall are anticipated to be located at Tolvaddon, Manhay, Penhallow and Mawla, although these locations are not final and are subject to change.
- Future geothermal capacity is expected to connect where there is geothermal potential, as seen in Figure 23, particularly around Land’s End, which is yet to be explored, and existing sites around St Austell and Camborne.

- Though there is potential heat resource on Dartmoor, this national park has been excluded to reflect the lack of network and road coverage, and potential planning barriers due to National Park status.

Figure 23 – Heat flow map of Cornwall, courtesy of Eden Geothermal



References:

WPD connection offer data, the Renewable Energy Planning Database, Regen consultation with local stakeholders and discussion with geothermal developers.

Marine and floating offshore wind in the South West licence area

Summary of modelling assumptions and results

Technology specification:

Small scale, demonstration and early-stage marine energy and floating offshore wind development projects:

- Wave energy – typically small array and demonstration projects
- Tidal energy, including stream, harnessing kinetic tidal flows around headlands, and tidal lagoon, harnessing potential energy created through tidal range
- Offshore floating wind – demonstration projects and small-scale commercial developments.

Includes comparison to FES 2021, as reported for Building Block ID number Gen_BB017 (tidal stream, wave power and tidal lagoons) and Building Block ID number Gen_BB014, covering all offshore wind.

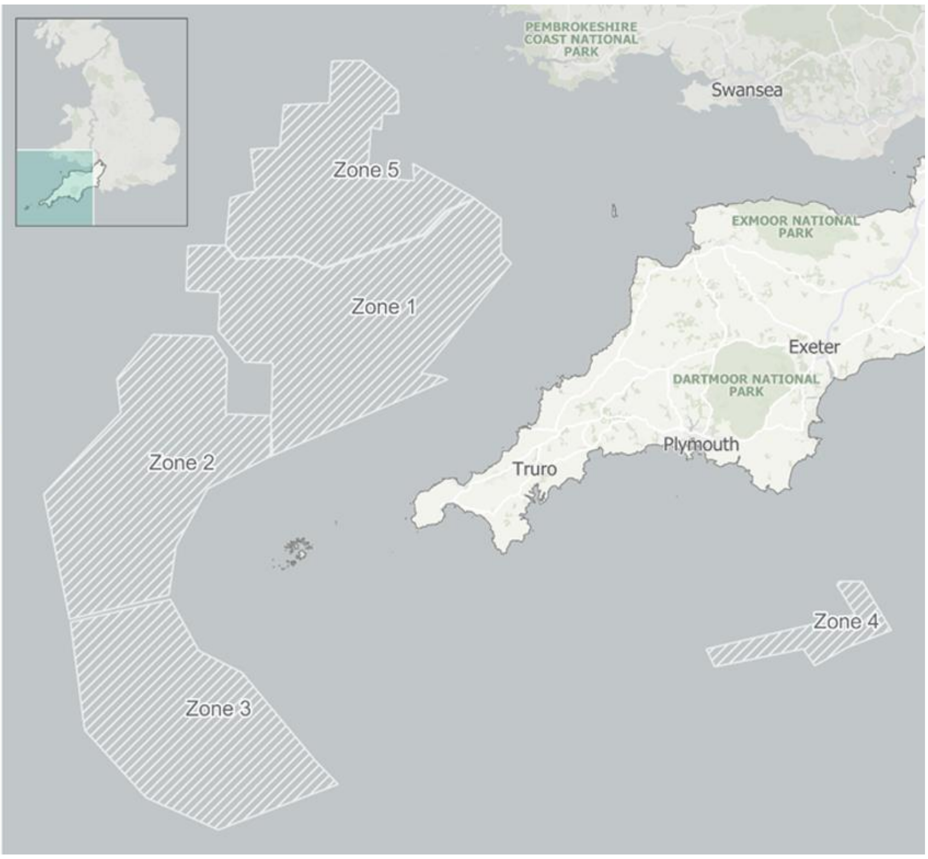
Data summary for marine and floating offshore wind in the South West licence area:

Installed power capacity (MW)		Baseline	2025	2030	2035	2040	2045	2050
Wave Energy	Steady Progression	0	0	0	0	0	0	0
	System Transformation		0	0	10	10	10	10
	Consumer Transformation		0	10	50	80	80	80
	Leading the Way		0	10	40	40	40	40
Tidal Stream Energy and Tidal Lagoon	Steady Progression	0	0	0	0	0	0	0
	System Transformation		0	0	5	5	5	5
	Consumer Transformation		0	5	10	15	15	15
	Leading the Way		0	5	10	15	15	15
Floating Offshore Wind	Steady Progression	0	0	0	0	0	0	0
	System Transformation		0	40	40	40	40	40
	Consumer Transformation		40	60	170	170	170	170
	Leading the Way		40	50	50	50	50	50

Summary:

- The sea around the south west of England has been identified by the UK government and regional bodies as a key strategic area for the development of offshore energy resources, including wave energy, tidal stream, tidal lagoon, and floating offshore wind.
- However, the withdrawal of specific subsidy support for wave and tidal energy in 2016 has affected industry confidence and has led to the withdrawal and delay of pre-commercial projects. This has particularly affected wave energy demonstration projects that were previously expected to connect to the distribution network at Hayle.
- Recently, marine energy developer attention has shifted towards floating offshore. Developers in the south west of England and South Wales are working closely together to develop potential sites in the Celtic Sea, with further potential in the west of the Isles of Scilly, and south of the Lizard in Cornwall, as shown in Figure 24.
- Marine technologies can connect to both the distribution and transmission networks, depending on scale, cost, and location. Therefore, the WPD DFES 2021 scenario projections primarily represent demonstration and pre-commercial projects that are expected to connect to the distribution network. Large-scale commercial projects are more likely to connect to the transmission network.
- As a result, **Consumer Transformation** has the highest marine energy capacity of 265 MW across all three technologies, while **Steady Progression** has no marine energy capacity.

Figure 24



Potential development zones for offshore floating wind

Courtesy of the Offshore Renewable Energy Catapult 2030 study.

Modelling assumptions and results:

Baseline (up to 31st March 2021)

- There are no operational baseline projects, although the Wave Hub demonstration site has a connection agreement (30 MW export capacity) and installed infrastructure.
- Withdrawal of specific subsidy support for wave and tidal energy in 2016 has affected pre-commercial projects. The previously identified wave energy projects that planned to connect at the Hayle substation have been withdrawn.
- Previously identified tidal stream projects that would have connected to the WPD network in North Devon have also been withdrawn and potential development in the North Devon Tidal Demonstration Zone has been abandoned, with the zone being handed back to the Crown estate.

Near term (April 2021 – March 2025)

- There are no pipeline sites with an accepted network connection offer in the South West licence area.
- Formerly called Wave Hub Development Services Ltd., the Cornwall Council-owned company has now changed its name to Celtic Sea Power to reflect its future in the development of floating wind and has received government backing to support floating wind deployments.
- The Wave Hub offshore renewable energy demonstration facility is in the process of being sold to Hexicon, a Swedish floating windfarm developer, who will use the site for 'TwinHub' – a 30-40 MW floating offshore wind project. In **Leading the Way** and **Consumer Transformation**, TwinHub is expected to connect at 40 MW in 2025, as the scenario with the highest level of green ambition.
- With lower levels of green ambition, the project is modelled to connect by 2030 under **System Transformation**. Due to a lack of connection agreement and planning permission, this site has not been modelled to connect under **Steady Progression**.
- In the near term, wave and tidal energy is expected to continue to focus on technology development with non-network exporting prototype deployments.
- With the abandonment of any developments at the North Devon Demonstration Zone, no tidal stream projects are expected to connect to the distribution network in the near term.

Medium term (April 2025 – March 2035)

- UK government is currently consulting[33] on how the Contract for Difference (CfD) mechanism could be tailored to support marine energy and the potential for further support through capital grants and the use of innovative PPAs. Previously, marine energy has benefitted from a 'ring fence minima' CfD; however, the withdrawal of this specific subsidy has reduced the competitiveness of marine energy and impacted development in the sector.
- Based on engagement with sector experts and stakeholders, if this support was to be reintroduced, marine energy, in particular wave energy, could experience a surge in investment and development.
- In **Leading the Way** and **Consumer Transformation**, with higher levels of UK government and regional support, it is assumed that pre-commercial scale wave energy sites gain interest and are supported to connect in the South West licence area.
- Under **Consumer Transformation**, a scenario that focuses on decentralised technology uptake, 50 MW of wave capacity is modelled to connect by 2035, with another 30 MW connecting by 2040.

- As scenarios that have more focus on transmission scale deployment, **Leading the Way** and **System Transformation** follow a similar trajectory in the medium term, but wave development is expected to connect at a transmission level in the long term.
- Wave energy has the potential to be co-located with floating offshore wind projects, as explored by Bombora off the coast of South Wales. For the South West licence area, this means that the development of wave energy is not hindered by parallel development of floating offshore wind.
- In the net zero compliant scenarios, additional small-scale floating wind demonstrations of c. 10-30 MW are projected to connect in the area around Hayle, following the development of the TwinHub site.
- In **Leading the Way** and **System Transformation**, future floating offshore wind capacity is expected to favour connection to the transmission network in the medium term.
- In contrast, under **Consumer Transformation**, it is expected that demonstration sites will continue to develop on the distribution network into the 2030s.
- Major floating wind projects, including the recently announced Whitecross project, could be developed in the Celtic Sea in the medium term under favourable conditions.
- Whitecross, a 100 MW demonstration project located off the coast of Devon and Cornwall, has been selected by the Crown Estate. The project is in the very early stages of development, and it is unclear if/when it is likely to connect, and to which network. Due to **Consumer Transformation**'s focus on distribution-connected technologies, the project has been modelled to connect to the distribution network by 2035 in this scenario.
- The potential for tidal stream energy will be limited by resource and suitable locations and will likely consist of smaller projects connected to the distribution network. These are expected to connect in North Devon due to the location of tidal resources.
- Tidal lagoon projects are expected to connect to the transmission network; therefore, no capacity has been projected in any scenario for the WPD DFES 2021.

Long term (April 2035 – March 2050)

- Although currently the commercial viability of marine energy technology remains unproven, in **Leading the Way** and **Consumer Transformation**, wave and tidal energy projects are assumed to prove successful in testing and are therefore deployed in the Celtic Sea and the Bristol Channel. This assumes specific government support for marine energy.
- There is no wave or tidal energy deployed under **Steady Progression**.
- Large scale commercial marine projects, including wave energy, floating offshore wind and tidal lagoon, are assumed to connect to the transmission network in the long term, mirroring the historic development of fixed offshore wind.

Figure 25

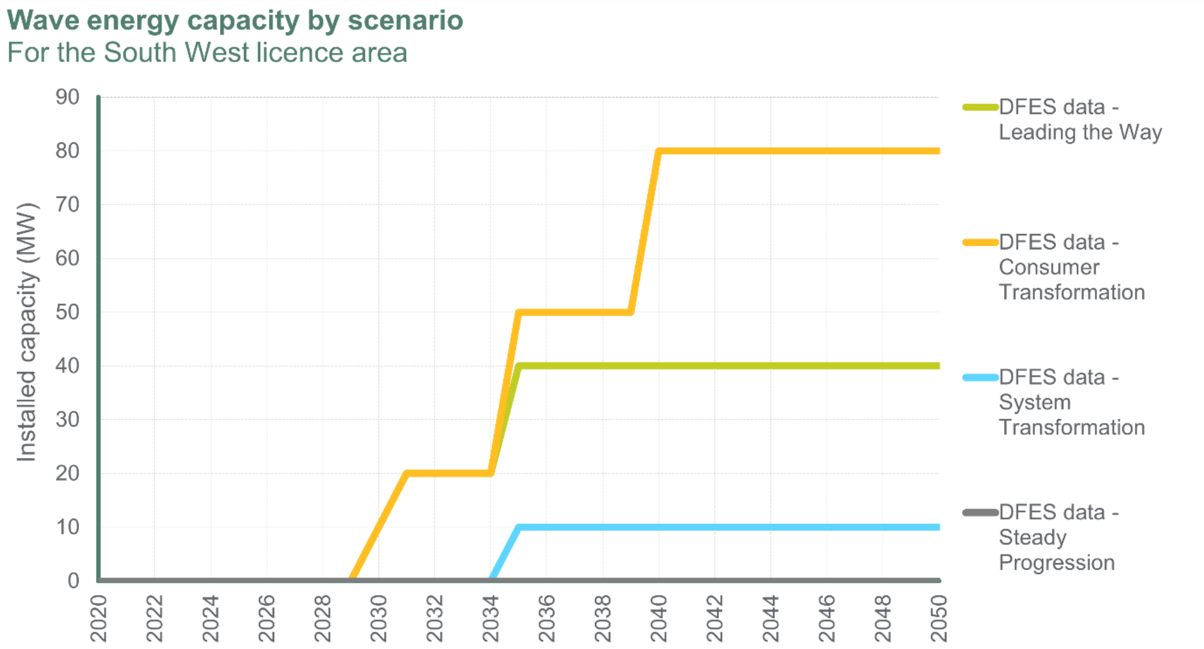


Figure 26

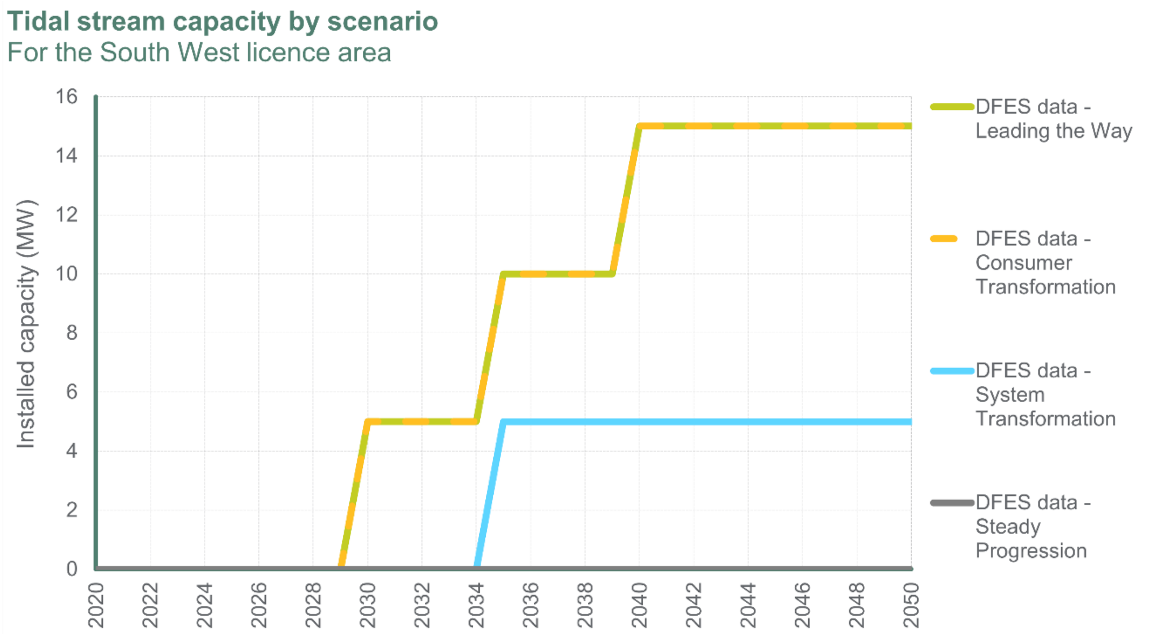
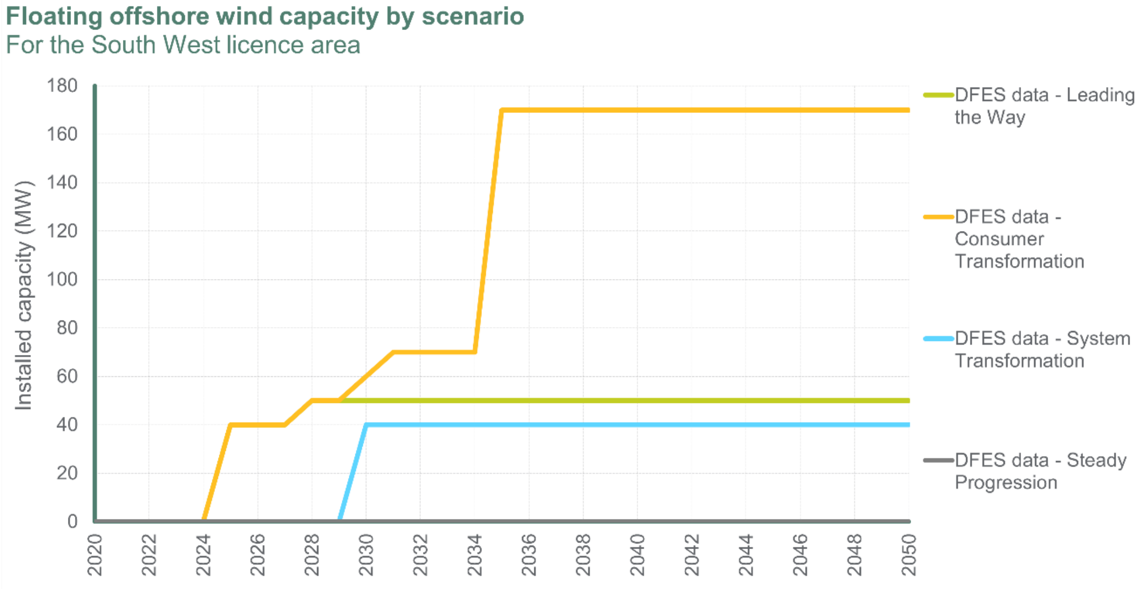


Figure 27



Reconciliation with National Grid FES 2021:

Wave and tidal energy

Results for wave and tidal energy relate to the FES 2021 data as reported for Building Block ID number Gen_BB017 (tidal stream, wave power and tidal lagoons).

- FES 2021 projects 301 MW of wave and tidal energy in the south west in 2050 under **Leading the Way**.
- WPD DFES 2021 projections are significantly lower than FES 2021, with a maximum wave and tidal capacity of 95 MW in 2050.
- The decision to deviate from the FES 2021 data was influenced by conversations with key stakeholders, who reflected that, with a shift in developer interest to floating offshore wind, wave and tidal energy in the south west could be limited, unless specific government support is put in place. If that was the case, pre-commercial demonstration projects are likely to connect to the distribution network, but large-scale commercial projects would more likely connect to the transmission network.

Floating offshore wind

Results for floating offshore wind relate to the FES 2021 data as reported for Building Block ID number Gen_BB014, covering all offshore wind.

- FES 2021 does not have any fixed or floating offshore wind capacity in the south west.
- WPD DFES 2021 projections deviate from this, due to:
  - Celtic Sea Power's commitment to connect the 40 MW TwinHub floating offshore wind project in 2025
  - The proposed Whitecross floating offshore wind farm
  - The potential for demonstration projects at distribution level prior to commercial floating offshore wind connecting to the transmission network.

Relevant assumptions from National Grid FES 2021:

Assumption number	4.1.2 - Other renewables including marine and hydro generation
Steady Progression	Low support and therefore other renewables cannot compete with low cost solar and wind generation.
System Transformation	Support for large-scale renewable technologies (i.e., tidal marine).
Consumer Transformation	Potential for many small-scale projects that will have larger societal impact coupled with support for marine technologies across all scales.
Leading the Way	Focus on rapid decarbonisation results in prioritising renewables that are available at lowest cost today (i.e., solar and wind). Innovation in other flexible solutions results in less need for a wide range of renewables.

Factors that will affect deployment at a local level:

- The location of wave, tidal and floating wind projects will be highly dependent on:
  - the available energy resource
  - seabed depths and conditions
  - marine designations and impacts on other marine users
  - port availability
  - access to the electricity network.
- Previous studies[34] have identified areas for development in the south west:
  - Wave energy off North Cornwall, the Lizard peninsula, and the Isles of Scilly
  - Tidal energy off headlands of North Devon (near Lynmouth) and the Bristol Channel
  - Floating offshore wind at locations in the Celtic Sea and to the West of Lundy, also potentially around Plymouth.
- Port facilities exist at Falmouth, Plymouth, Bristol and North Devon, and likely onshore network connections include the WPD substation at Hayle and the National Grid substation at Alverdiscott. However, connection could be impacted by the potential development of interconnectors to Ireland and France.

Stakeholder input:

Marine energy and floating offshore wind have been identified as a key energy and economic opportunity for the south west of England and Cornwall in particular. It features strongly in the Cornwall and Isles of Scilly LEP industrial strategy and net zero carbon planning. There is also strong interest from both Plymouth and Bristol city regions.

The Regen DFES team has undertaken direct discussion with floating wind and marine energy developers, the Celtic Sea Power operations team and has been part of the south west floating offshore wind and marine networks. These conversations have directly influenced some of the WPD DFES 2021 modelling decisions around the near-term pipeline and future potential for distributed marine energy potential.

References:

UK government consultation on support for wave and tidal energy using Contracts for Difference (2020), Celtic Sea Power, Cornwall and Isles of Scilly Draft Industrial Strategy, Cornwall and Isles of Scilly Climate Change Action Plan, The Crown Estate.

Biomass generation in the South West licence area

Summary of modelling assumptions and results

Technology specification:

Biomass generation – including biomass for power generation and biomass CHP. Excludes biomass used solely for heat, and bioenergy with carbon capture and storage. The common feedstocks for biomass generation in the UK are plants, such as corn and soy, and wood, in the form of straw or wood chips.

This technology pertains to Building Block ID number Gen_BB010 in the FES 2021 data.

Data summary for biomass generation (including CHP) in the South West licence area:

Installed capacity (MW)	Baseline	2025	2030	2035	2040	2045	2050
Steady Progression	1	1	1	1	1	1	1
System Transformation		1	1	1	1	1	1
Consumer Transformation		1	1	1	1	1	1
Leading the Way		1	1	1	1	1	1

Summary:

- The South West has proven a difficult area for biomass developers in the past. There have been ten unsuccessful planning applications in this licence area for biomass generation, two of which were over 100 MW.
- Two of these applications were refused in planning. Eight other sites either withdrew or abandoned their planning applications.
- No increase in biomass power capacity past the pipeline is assumed under any scenario in the South West licence area, due to a difficult planning environment and a shift in the use of biomass.
- In general, biomass fuel sources are assumed to be prioritised for other uses such as in increased carbon sinks and for use in construction. This reflects the recommendations from the Committee on Climate Change in their report 'Biomass in a low-carbon economy'[35].
- BECCS is expected to be the largest use of feedstocks in the long term, but this is assumed to connect at transmission level.
- Smaller scale biomass generation sites, such as those that have local feedstock supply chains and/or provide heat as well as power, are assumed to continue generating out to 2050 in all scenarios.

Modelling assumptions and results:

Baseline (up to 31st March 2021)

- There are four biomass power sites operational in the South West licence area, totalling 1.3 MW of power generation capacity.
- Two of these connected in 2015, while the others connected in 2017. There has been no development since.
- Two of these sites have biomass CHPs installed.

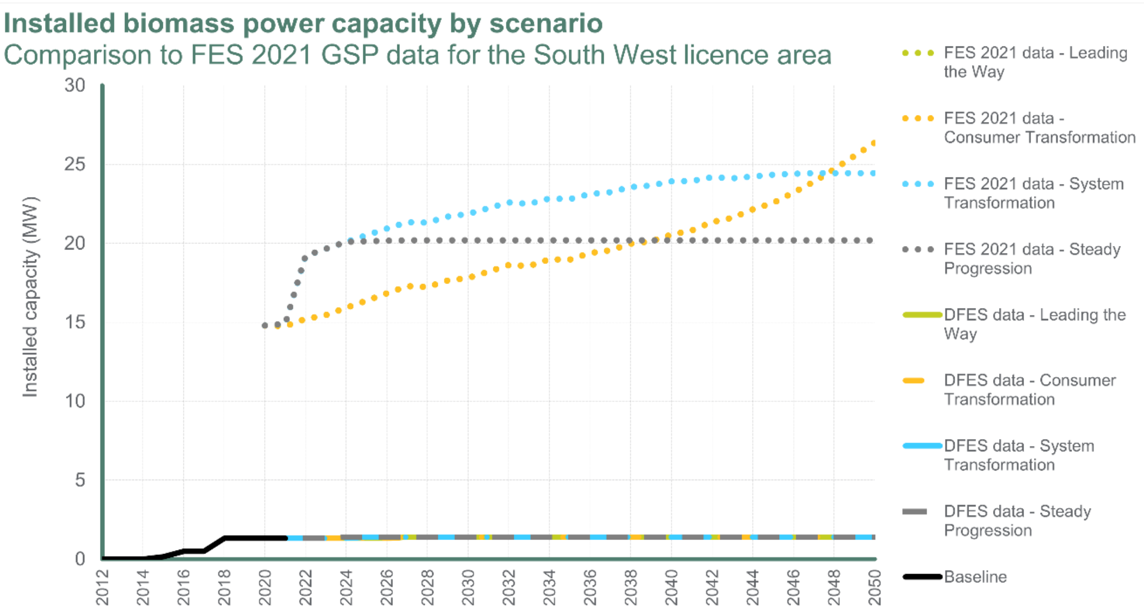
Near term (April 2021 – March 2025)

- There is one 65 kW site with an accepted connection offer from WPD in the pipeline.
- This project, including the installation of a biomass CHP, was granted planning permission by South Gloucestershire Council in January 2020.
- Based on analysis of REPD, historically biomass projects take 3.4 years from gaining planning permission to becoming operational. As a result, this project has been modelled to connect between 2023 and 2026, depending on the scenario.
- The REPD includes a 3.9 MW site in Somerset that submitted a planning application in 2020. However, considering over three quarters of biomass planning applications submitted in the South West are either refused, abandoned or withdrawn, and given the lack of a connection agreement, this site has not been modelled to connect under any scenario. This could change in the future with further progression through the planning process.

Medium and long term (April 2025 – March 2050)

- Smaller scale biomass generation sites, such as those that have local feedstock supply chains and/or provide heat as well as power, are assumed to continue generating out to 2050 in all scenarios.
- In general, biomass fuel sources are assumed to be prioritised for other uses such as BECCS, which is expected to be the largest use of feedstocks in the long term. This is assumed to connect at transmission level, so any development in the medium and long term is not anticipated to be on the distribution network.

Figure 28



Reconciliation with National Grid FES 2021:

Results in this section relate to the FES 2021 data as reported for the Building Block ID number Gen_BB010.

- WPD DFES 2021 analysis shows there is only 1.3 MW of operational biomass capacity in the South West licence area.
- This is significantly lower than the FES 2021 baseline, hence WPD DFES 2021 projections are lower than FES 2021 under all scenarios. This could be to different allocations across licence area boundaries, or of individual project technologies. For example, there are some energy from waste sites that burn waste wood, and could conceivably be classed as biomass.

Factors that affect deployment at a local level:

The spatial distribution of biomass generation is based on the location of existing baseline and pipeline sites connecting to the distribution network in the South West licence area.

Relevant assumptions from National Grid FES 2021:

Assumption number	4.1.13 - Biomass and Energy from Waste (EfW) generation with CCUS
Steady Progression	Limited support for BECCS due to less of a drive to decarbonise and slowest deployment of CCUS. Some growth in decentralised biomass without CCUS.
System Transformation	High growth driven by the decarbonisation agenda. Linked to CCUS as this results in negative emissions.
Consumer Transformation	High growth driven by the decarbonisation agenda. Linked to CCUS as this results in negative emissions.
Leading the Way	Uptake driven by the decarbonisation agenda. Linked to CCUS as this results in negative emissions.

References:

WPD connection offer data, the Renewable Energy Planning Database, Regen consultation with local stakeholders and sector representatives, the CCC.

Renewable engines (landfill gas, sewage gas, biogas) in the South West licence area

Summary of modelling assumptions and results for anaerobic digestion

Technology specification:

Installed capacity of biogas renewable engines, using biomethane for electricity generation only. This is the 'biogas' component of the building block technology "Renewable engines (landfill, sewage, biogas)" under Building Block ID number Gen_BB004 in the FES 2021 data and is referred to as Anaerobic Digestion (AD) in the WPD DFES 2021.

Data summary for Anaerobic Digestion in the South West licence area:

Installed capacity (MW)	Baseline	2025	2030	2035	2040	2045	2050
Steady Progression	27	31	32	33	33	33	34
System Transformation		32	36	40	41	42	43
Consumer Transformation		32	40	50	54	56	59
Leading the Way		32	40	51	55	60	65

Summary:

- The South West licence area has 27 MW of operational AD capacity.
- Further deployment of AD plants requires sufficient local feedstock either from agricultural or food waste.
- There are two pipeline sites with an accepted connection agreement, with a total capacity of 3.8 MW. These both have planning permission granted, so are expected to connect in all scenarios. These are projected to connect between 2023 and 2026, depending on the scenario.
- Additional capacity could be developed to produce biomethane for use in transport or injection into the gas network, rather than burnt for electricity generation. These competing business models makes for an uncertain future for AD, and results in a range of future projections under the four scenarios.

Modelling assumptions and results:

Baseline (up to 31st March 2021)

- There are 27 operational sites connected to the distribution network in the South West licence areas, totalling 27.4 MW.
- The largest of these is a 5 MW site in Holsworthy, Torridge, which connected in 2015.
- The most recent connection was a 124 kW site in Evercreech in 2019.

Near term (April 2021 – March 2025)

- Despite challenges due to the COVID-19 pandemic, the UK AD sector grew by 11% in the year to April 2021[36].
- There are two pipeline sites in the South West licence area, with an accepted network connection offer, totalling 3.8 MW.

- Both of these sites were granted planning permission (in 2013 and 2019) and are now awaiting construction.
- Based on analysis of REPD, historically AD projects take 2.2 years from receiving planning permission to becoming operational. As a result, these sites connect between 2022 and 2024, depending on the scenario.

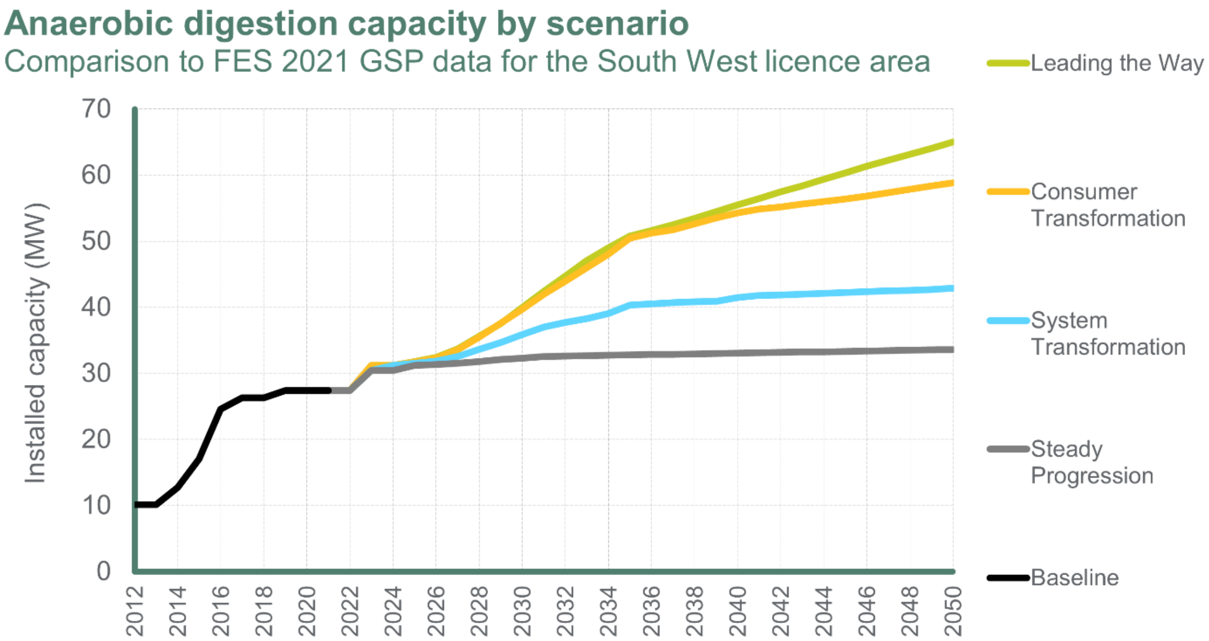
Medium term (April 2025 – March 2035)

- There is scope for an increase in the availability of household food waste as a feedstock in the near term, as only c. 49% of the South West licence area is covered by a food waste collection scheme.
- Considering the government's commitment to roll out separate household food waste collection across the country by 2023[37], there could be an increase in feedstock in the mid-2020s. However, this feedstock is unlikely to significantly increase post 2025.
- Increases in capacity are likely to be driven by farm-based AD, particularly from the significant number of dairy farms in the South West.
- The removal of government support mechanisms for electricity generation from biomethane, and implementation of the Green Gas Support Scheme (designed to accelerate the decarbonisation of the gas grid), is likely to improve the business case for AD plants to sell their biomethane – dampening growth in biomethane-fuelled electrical capacity in the mid-term across the three net zero scenarios.
- Deployment of capacity is very limited under **Steady Progression**, due to an assumed lack of incentives for biomethane production and a focus on its use for gas-to-grid.

Long term (April 2035 – March 2050)

- The main sources of AD feedstock are food waste, agricultural waste, such as crop waste and manure, and energy crops. These are all under risk of depleting in the long term, with changes to land use and societal shifts (per person food waste is assumed to decrease towards 2050); however, this is still uncertain.
- Through stakeholder engagement, it was concluded that deployment of AD plants for electricity generation is expected to remain low in the long term, although there is still likely to be deployment on rural farms, as currently only 3% of agricultural waste produced in the UK annual is used to fuel AD plants[36].
- Under **System Transformation**, government may focus incentives for biomethane on gas-to-grid injection rather than power generation. Under this scenario, it is assumed that the electricity grid is decarbonised by other renewable technologies, including large-scale BECCS.
- Significant increases in electricity generation capacity from AD are most likely to occur in high-renewables scenarios, notably **Leading the Way** and **Consumer Transformation**, focussing on burning biomethane as a form of dispatchable flexible generation. Operators would be able to capture high electricity prices in periods of low renewable generation or high demand.
- Under these scenarios, improvements in engine technology are also likely to reduce the overall cost of projects, meaning operators are less reliant on subsidies.
- **Steady Progression** has limited deployment across the projection period, representing a lack of incentives for biomethane production and a focus on its use for gas-to-grid.

Figure 29



Factors that will affect deployment at a local level:

- The location of all new capacity out to 2025 is based on the existing pipeline sites with an accepted grid connection offer. After this pipeline deployment, local factors have been used to weight projections from 2025 onwards, such as:
    - agricultural land grades 1 & 2[38], relative to the GB average
    - food waste collection potential by local authority
    - anaerobic digestion resource assessment, which considers the energy generation potential from manure (including waste from poultry, cattle and pigs, but excluding sheep)

Stakeholder engagement:

As part of the WPD DFES stakeholder engagement process, Regen delivered a series of webinars with WPD in June 2021. In the webinars, the long-term role of distribution-scale bioenergy electricity generation was considered. 81% of respondents thought that these sites would have a similar or expanded role to bioenergy electricity generation today. This feedback has directly influenced the WPD DFES 2021 analysis for all licence areas, by confirming the focus on anaerobic digestion as a form of low carbon, dispatchable, flexible electricity generation.

Summary of modelling assumptions and results for landfill gas

Technology specification:

Landfill gas installed capacity used for electricity generation only.

Data summary for landfill gas in the South West licence area:

Installed capacity (MW)	Baseline	2025	2030	2035	2040	2045	2050
Steady Progression	35	41	41	41	41	41	41
System Transformation		37	37	26	20	16	4
Consumer Transformation		37	37	26	20	16	4
Leading the Way		37	26	20	16	4	4

Summary:

- Landfill gas capacity for electricity generation is expected to decline over time in all net zero compliant scenarios, based on the assumption that society transitions towards a low/zero waste lifestyle.
- Baseline sites are modelled to decommission in line with scenario specific operational lifetimes.

Modelling assumptions and results:

Baseline (up to 31st March 2021)

- There are 17 operational sites connected to the distribution network in the South West licence area, totalling 35 MW.
- The largest of these sites is a 5.5 MW landfill gas plant in Hallen, South Gloucestershire. This site connected in 1991.
- The most recent site to connect was a 2 MW site in 2016.

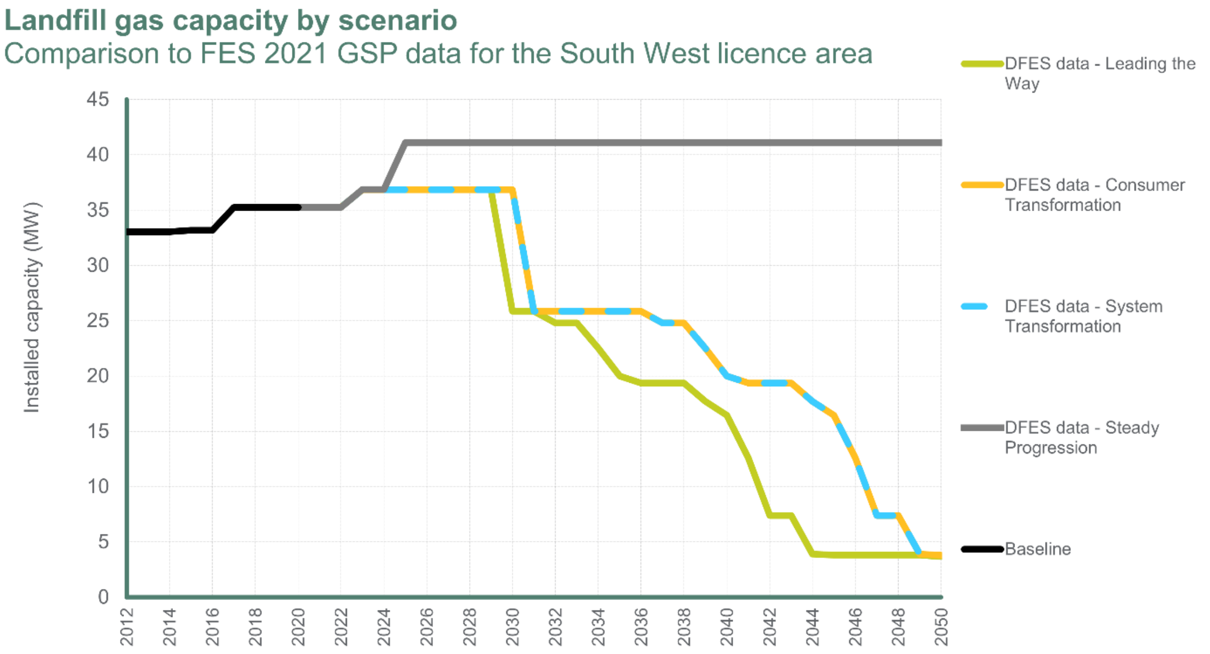
Near term (April 2021 – March 2025)

- There are two sites with an accepted connection agreement in the South West licence area.
- A 1.6 MW site was granted planning permission in 2014, while the other site has a capacity of 4.3 MW and does not currently have any planning information.
- Based on analysis of REPD, historically landfill gas projects take 2.8 years from submitting a planning application to become operational, taking on average 2.2 years once planning permission has been granted.
- As a result, the 1.6 MW project connects in 2022 under all scenarios, while the 4.3 MW site only connects under **Steady Progression** and in 2024.

Medium and long term (April 2025 – March 2050)

- Electricity generation from landfill gas is at odds with net zero targets, due to the level of associated carbon emissions. Hence, it is assumed that capacity reduces after 2030 in **Leading the Way**, **Consumer Transformation** and **System Transformation**, as older facilities reach the end of their operational lifetime.
- Although there is likely to be a gradual decline in waste resources in the net zero compliant scenarios, it is assumed that sites will not disconnect until the end of their operational life.
- In **Leading the Way**, sites are modelled to have a 35-year operational lifetime, while the operational life under **Consumer Transformation** and **System Transformation** is modelled to be 40 years.

Figure 30



Factors affecting deployment at a local level

The spatial distribution of landfill gas capacity is based on the location of existing baseline and pipeline sites connecting to the distribution network in the South West licence area.

Summary of modelling assumptions and results for sewage gas

Technology specification:

Sewage gas installed capacity used for electricity generation only.

Data summary for sewage gas in the South West licence area:

Installed capacity (MW)	Baseline	2025	2030	2035	2040	2045	2050
Steady Progression	28	28	5	2	1	0	0
System Transformation		28	25	10	5	2	1
Consumer Transformation		28	28	28	28	28	28
Leading the Way		28	28	28	28	28	28

Summary:

- There are currently no pipeline sites in the South West licence area for sewage gas, hence future deployment is limited.
- There is no increase in distribution connected sewage gas capacity in the South West licence area under any scenario, due to industry feedback that sewage gas for gas-to-grid injection is the favoured future business model.
- Any increase in sewage sludge resource, either due to the tightening of environmental permits or an increase in population, is expected to be used for gas-to-grid injection rather than electricity generation.
- **System Transformation** and **Steady Progression** represent future scenarios in which sewage sludge resource is prioritised for other low carbon options.

Modelling assumptions and results:

Baseline (up to 31st March 2021)

- There are 18 operation sewage gas sites connected to the distribution network in the South West licence area, totalling 28.2 MW.
- The largest of these is a 12 MW site in Avonmouth, which connected in 1999.
- The most recent site to connect was a 1.25 MW site in Newquay in 2015.

Near term (April 2021 – March 2025)

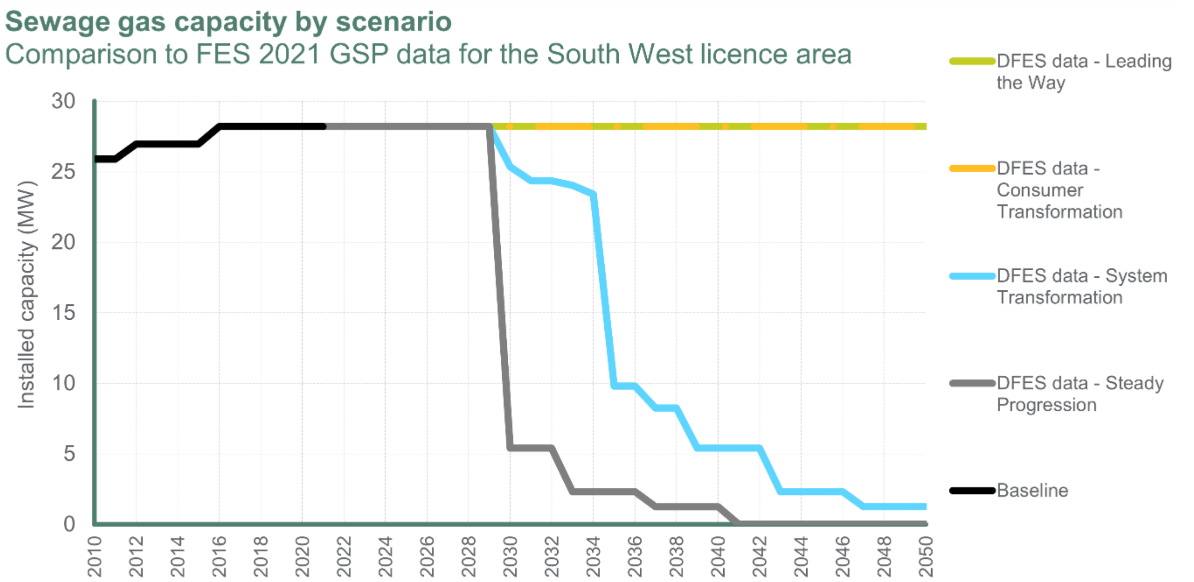
- There is no change projected in the output capacity or connections before 2025.

Medium to long term (April 2025 – March 2050)

- There is no additional capacity projected under **Consumer Transformation** or **Leading the Way**, while capacity reduces under **System Transformation** and **Steady Progression**. This is due to industry feedback on the future of sewage gas, highlighting that any increase in capacity in sewage gas sites will likely be for gas-to-grid injection, biomethane production or bio-hydrogen production rather than electricity generation, due to:

- the larger decarbonisation impact
- the expiration of ROCs and minimal activity in the CfD programme, which may make electricity generation from sewage gas less attractive
- support for green gas production, such as through the green gas levy, which may result in a decline for electricity generation in **System Transformation** and **Steady Progression**
- prioritisation of the decarbonisation of heat and transport via 'green gas'.

Figure 31

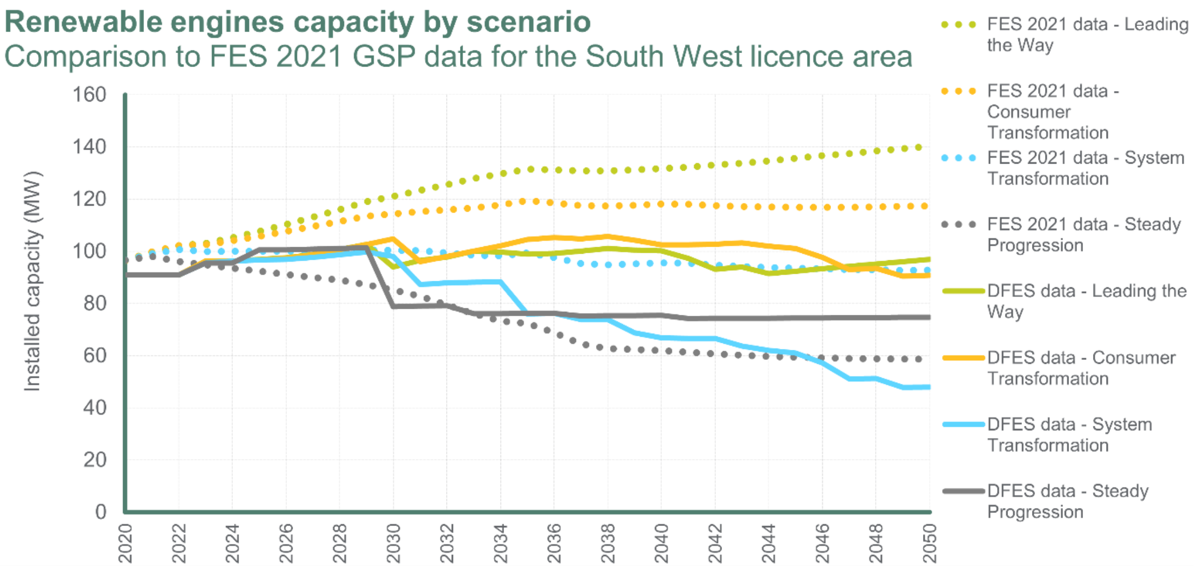


Factors affecting deployment at a local level

The spatial distribution of sewage gas capacity is based on the location of existing baseline and pipeline sites connecting to the distribution network in the South West licence area.

Summary of anaerobic digestion, landfill gas and sewage gas compared to the FES 2021 'Renewable engines (landfill, sewage, biogas)' building block.

Figure 32



Reconciliation with National Grid FES 2021:

Results in this section relate to the FES 2021 data as reported for the Building Block ID number Gen_BB004.

- The increase in renewable engines capacity in the South West licence area in the medium term comes primarily from an increase in anaerobic digestion capacity as landfill gas and sewage gas capacity remains constant or decreases over time.
- In the long term, the trend is dominated by landfill gas capacity coming offline, which results in a decrease in overall renewable engines capacity in the WPD DFES 2021.
- The WPD DFES 2021 projections are generally below FES 2021 under **Leading the Way**, **Consumer Transformation** and **System Transformation**, as it has been assumed that the landfill gas sites are decommissioned after an operational life of 35 – 40 years, due to a reduction in available waste resource.
- The long-term maximum capacity of renewable engines is based on assumed declining levels of waste production. Additional deployment in this sector is expected to be focussed on gas-to-grid biomethane injection rather than electricity generation, which is not in the scope of WPD DFES 2021.

Relevant assumptions from National Grid FES 2021:

Assumption number	1.1.5 - Support: incentive regime for biomethane (and other 'green gas') production.
Steady Progression	Support is focussed on areas with greater potential volumes (UKCS/shale).
System Transformation	Bigger push for renewable gas as required to meet longer term decarbonisation targets.
Consumer Transformation	Bigger push for renewable gas as required to meet longer term decarbonisation targets.
Leading the Way	All sources of renewable fuels encouraged and biomethane used in niche areas in transport/industry.

References:

WPD connection offer data, local authority food waste collection status, Regen resource assessment, land grade statistics, water sector representatives, the Renewable Energy Planning Database, Regen consultation with local stakeholders and discussion with developers.

Fossil gas-fired power generation in the South West licence area

Summary of modelling assumptions and results

Technology specification:

Fossil gas-fired power generation connected to the distribution network, covering four known fossil gas generation technology types:

- Close cycle gas turbines (CCGT) – Building block Gen_BB009
- Open cycle gas turbines (OCGT) – Building block Gen_BB008
- Gas reciprocating engines – Building block Gen_BB006
- Gas combined heat and power plants (gas CHP) – Building block Gen_BB001

There are no operational CCGT sites or any proposed sites with an accepted connection offer in the South West licence area. The analysis does not include back-up gas CHPs or engines located on some commercial and industrial premises that are only operated when mains supply failure occurs and cannot export.

Data summary for fossil gas-fired power generation in the South West licence area:

Installed capacity (MW)		Baseline	2025	2030	2035	2040	2045	2050
OCGT (non-CHP)	Steady Progression	129	129	129	129	129	129	129
	System Transformation		129	58	58	0	0	0
	Consumer Transformation		129	58	58	0	0	0
	Leading the Way		58	58	0	0	0	0
Reciprocating engines (non-CHP)	Steady Progression	72	207	284	319	306	274	213
	System Transformation		140	163	141	62	20	0
	Consumer Transformation		140	157	112	62	23	0
	Leading the Way		140	130	31	0	0	0
Gas CHP	Steady Progression	186	188	188	187	187	101	66
	System Transformation		188	188	171	34	15	0
	Consumer Transformation		188	180	54	35	20	0
	Leading the Way		188	180	86	0	0	0

Summary:

- There is a significant baseline (c.390 MW) of existing operational fossil gas-fired generation connected to the distribution network in the South West licence area. This ranges from 20+ year old gas power stations to small-scale gas CHPs connected behind-the-meter at commercial buildings less than 12 months ago.
- There is also a notable pipeline of new prospective fossil gas generation sites (c.178 MW) in the licence area. Some of these sites have positive activity in Capacity Market auctions and have resultantly been modelled to come online in the near-term in all scenarios.
- All types of fossil gas-fired power generation significantly decrease in the three net zero scenarios out to 2050. The installed capacity of gas reciprocating engines and gas CHPs increases under **Steady Progression** in the medium/long term.
- The primary role of distribution-scale fossil gas-fired generation is to provide flexibility and back-up services. Whilst the installed capacity may remain stable in some scenarios, the annual operating hours and energy output, decreases significantly by 2050 in all scenarios as the electricity system is decarbonised.
- At a national level, after 2030 hydrogen generation becomes a potentially economical source of supply-side flexibility in some scenarios. This results in some existing fossil gas generation site locations 'repowering' to become hydrogen-fuelled generation sites in between 2035 and 2050. The hydrogen generation scenario analysis and results are outlined in a separate dedicated technology summary sheet.

Results:

Baseline (up to 2021)

- There are 47 fossil-gas generation sites connected in the South West licence area, totalling 387 MW. This is broken down into the following fossil gas technologies:
    - Three OCGT sites totalling 129 MW
    - 10 gas reciprocating engines totalling 72 MW
    - 34 gas CHP sites totalling 186 MW.
- There were no CCGT sites identified with a distribution network connection agreement in the South West licence area.

Near term (April 2021 – March 2025)

- Consultation with stakeholders suggested that fossil gas-fired generation will see limited development beyond the current pipeline, due to its carbon intensity.
- There are 19 pipeline sites, totalling 178 MW, which have an accepted network connection offer in the licence area:
    - The pipeline sites are all gas reciprocating engine sites, except for a 2 MW gas CHP, to be located at Taw Valley Creamery in North Tawton in mid Devon. This gas CHP site secured planning approval earlier in 2021 and has been modelled to come online in 2022 in all scenarios.
    - Four pipeline sites totalling 20 MW have successfully secured capacity agreements in recent capacity market auctions, for 2022, 2023 or 2024 delivery years. These sites were also modelled to come online in all scenarios, based on the Capacity Market delivery year, as evidence of contractual commitments to connect in the mid-2020s.
    - Three pipeline sites totalling 47 MW successfully pre-qualified for a Capacity Market auction but did not secure a capacity agreement.
    - Four pipeline sites totalling 29 MW entered but did not pre-qualify in recent Capacity Market auctions.
    - For the remaining seven pipeline sites (79 MW), no development evidence was found.
- This analysis of planning and activity in Capacity Market auctions are key factors for the year of connection in the near term for each of the scenarios.

- The Industrial Emissions Directive, in place since 2016, places emissions requirements on large power plants, with limitations on the annual operating hours. This affects some large plant in the area, with operational hours assumed to reduce across the projection period even if installed capacity stays level.

Medium term (April 2025 – March 2035)

For OCGT:

- All OCGT capacity is modelled to decommission in the three net zero scenarios. This happens by 2031 in **Leading the Way** and by 2036 in **Consumer Transformation** and **System Transformation**.
- Under **Steady Progression**, the 129 MW of existing OCGT capacity remains online throughout the projection period to 2050. This reflects gas turbine technology providing system flexibility alongside more responsive gas engine technologies, and less action on decarbonisation.

For gas reciprocating engines:

- Under **Leading the Way**, gas reciprocating engine capacity sees a steady reduction across the medium term, with all capacity decommissioned by 2036 in this scenario. This reflects a rapid switch to alternative low carbon sources of flexibility.
- Under **System Transformation** and **Consumer Transformation**, a moderate amount of reciprocating engine capacity continues to connect to the distribution network in the medium term, reflecting a moderately slower transition to lower carbon flexibility.
- Under **Steady Progression** notable additional reciprocating engine capacity continues to connect to the distribution network in the medium term, reflecting this rapid-response technology continuing to win flexibility and reserve service contracts.

For gas CHP sites:

- Most of the gas CHP sites in the licence area are small-to-medium assets located onsite at commercial buildings such as hospitals, universities or industrial sites.
- There is no increase in gas CHP capacity under any scenario out to 2050.
- Under **Leading the Way** and **Consumer Transformation** a proportion of the older, legacy onsite gas CHP assets begin to decommission, with c.100-130 MW coming offline between 2025 and 2036 in these two scenarios respectively. Under these scenarios these businesses seek low-carbon alternatives to meet their onsite heat and power needs.
- Under **System Transformation** a small amount of gas CHP is decommissioned, reflecting a slower transition away from gas in this scenario.
- Under **Steady Progression** the gas CHP baseline continues to operate in the medium term.

Long term (April 2035 – March 2050)

For OCGT:

- OCGT capacity remains online and steady at 129 MW under **Steady Progression** to 2050.

For gas reciprocating engines:

- Under **Leading the Way**, all gas reciprocating engine capacity is decommissioned by 2036.
- Under **System Transformation** and **Consumer Transformation**, capacity steadily decommissions between 2032 and 2050, with no capacity on the network by 2050.
- Under **Steady Progression** reciprocating engine capacity peaks in 2035 at c.320 MW. Some capacity is modelled to decommission between 2035 and 2050, reflecting some transition away from fossil-fuel flexibility. However, c.210 MW of reciprocating engine capacity remains operational on the distribution network by 2050 under this scenario.

For gas CHP sites:

- Under **Leading the Way**, all gas CHP capacity is decommissioned by 2036.
- Under **System Transformation** and **Consumer Transformation**, after an initial rapid decommissioning of legacy CHP sites, connected capacity continues to steadily decline between 2038 and 2050. This culminates in no gas CHP capacity operating on the distribution network in either scenario by 2050.
- Under **Steady Progression** a number of gas CHPs also decommission across the 2040s, with c.65% of the baseline capacity decommissioned by 2050. 66 MW of gas CHP capacity remains operational in 2050 under this scenario.

Figure 33

OCGT installed generating capacity
Comparison to FES 2021 GSP data for the South West licence area

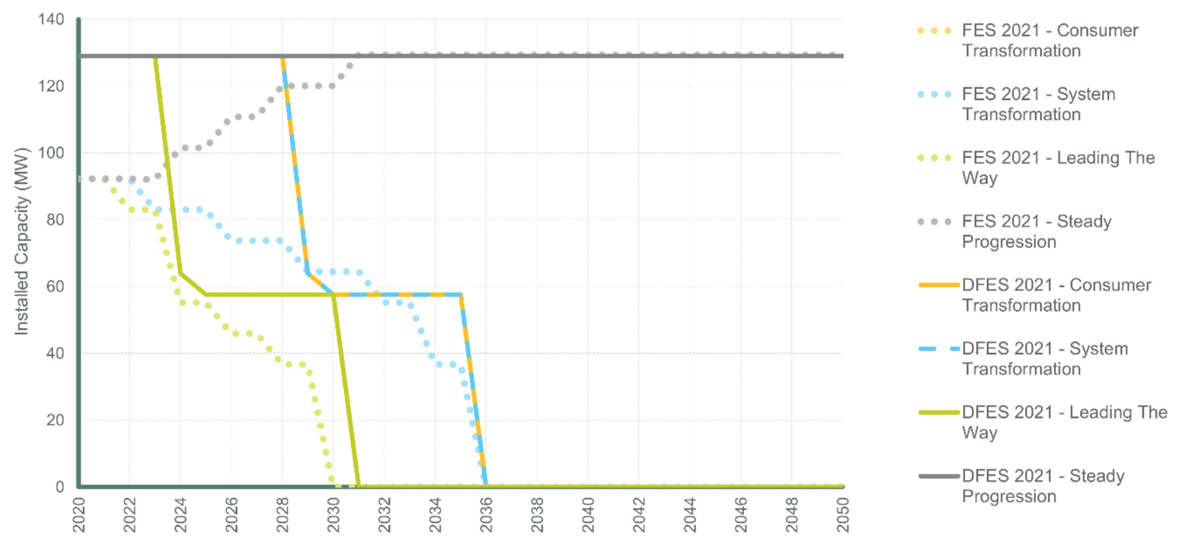


Figure 34

Gas reciprocating engine installed generating capacity
Comparison to FES 2021 GSP data for the South West licence area

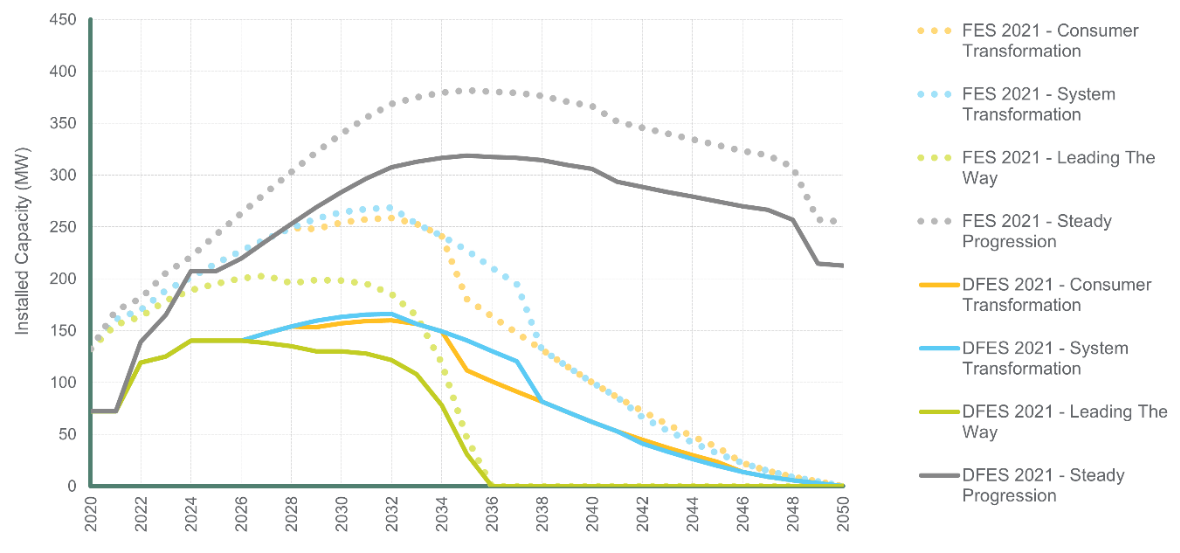
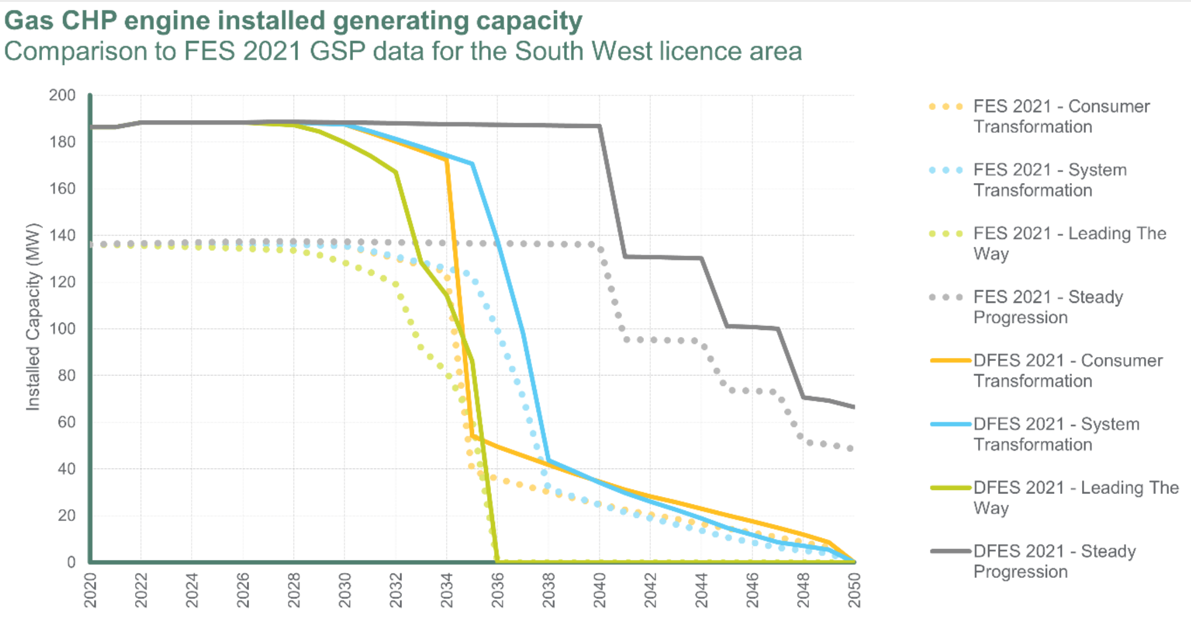


Figure 35



Reconciliation with National Grid FES 2021:

- For all of the fossil gas technologies included, the DFES has sought to classify each of the baseline sites based on connection data held by WPD and through site-by-site reconciliation with Capacity Market registers published by the EMR Delivery Body.
- The pipeline of sites with accepted connection offers were also individually assessed for evidence of development through reviewing online planning portals for planning activity and Capacity Market registers for capacity auction activity.
- These analyses have resultantly caused some variances between the FES and the DFES in the 2021 baseline and in the near-to-medium term projections.
- Beyond the known pipeline, the DFES has trended more towards the FES out to 2050 for all of the gas fired generation technologies.

For OCGT:

- The DFES has identified c.32 MW more OCGT capacity in the 2021 baseline than the FES. The reason for this is unclear.
- In the near-to-medium term in the net zero scenarios, the DFES has sought to decommission the (relatively large) baseline sites individually based on their connection year. This has resulted in more rapid reductions in connected capacity than the FES, which has a more staggered approach to the decommissioning of capacity. The year that the decommissioning culminates in these scenarios is closely aligned to the FES.
- Under **Steady Progression**, no pipeline sites were classified as OCGT in the DFES, therefore no increase in capacity has been modelled and the 129 MW existing operational capacity remains flat to 2050.

For reciprocating engines:

- The DFES has identified c.60 MW less reciprocating engine capacity in the 2021 baseline than the FES. The reason for this is unclear but could be related to differences in gas generation technology classification.
- The analysis of the pipeline in the DFES has resulted in a wider spread of projections between **Steady Progression** and the other three scenarios than seen in the FES.

- Beyond the analysis of the known pipeline, the DFES trends towards the FES out to 2050, but resulting in a moderately lower residual connected capacity operating in 2050 under **Steady Progression**.

For gas CHPs:

- The DFES has identified c.50 MW more gas CHP capacity in the 2021 baseline than the FES. The reason for this is unclear but could be related to differences in gas generation technology classification.
- The DFES and FES both assume minimal decommissioning of gas CHPs up until the early 2030s. Beyond this, the DFES sees a sharper disconnection of legacy CHP sites under **Leading the Way** than the FES.
- A moderately higher residual gas CHP capacity is modelled to continue operating in 2050 under **Steady Progression** in the DFES than the FES, due to the higher baseline.

Factors that will affect deployment at a local level:

- The spatial distribution of new gas-fired generation capacity is based on:
  - The location of the known pipeline sites
  - Proximity to electricity network and gas network infrastructure

Relevant assumptions from National Grid FES 2021:

Assumption number	**4.1.6 - Level of installed capacity of large unabated fossil-fuelled generation (e.g. CCGTs)**
Steady Progression	Low gas price and lower focus on decarbonisation promotes gas as the source of flexible generation.
System Transformation	High levels of decarbonisation, plus other sources of flexibility reduce the need for unabated gas.
Consumer Transformation	High levels of decarbonisation, plus other sources of flexibility reduce the need for unabated gas.
Leading the Way	Highest level of decarbonisation significantly reduces the amount of unabated gas.
Assumption number	**4.1.32 - Level of installed capacity of peaking generation (e.g. gas reciprocating engines and later hydrogen plant)**
Steady Progression	Initial strong growth in unabated gas reciprocating engines and stays high as gas generation (small and large) plays an increasingly important role as flexible generation in the absence of strong growth in other technologies (e.g. storage, interconnection)
System Transformation	Initial slow growth (low deployment of gas reciprocating engines). Later strong growth in hydrogen plant to support system flexibility.
Consumer Transformation	Initial slow growth (low deployment of gas reciprocating engines). Later moderate growth in hydrogen plant to support system flexibility.
Leading the Way	Low throughout: initial growth of gas reciprocating engines is low as not aligned to decarbonisation and low long-term growth as other flexible solutions dominate in this scenario.

Stakeholder feedback overview:

Fossil gas-fired generation	
Your comments to us	Our response
A strong majority of stakeholders thought that flexible fossil gas-fired generation would see limited development beyond the current pipeline, due to it being a fossil fuel.	We have modelled little-to-no new unabated gas-fired generation development beyond current pipeline projects in the three net zero compliant scenarios.
You asked whether hydrogen could replace fossil gas as a fuel for peaking generation.	Hydrogen-fired peaking plants are under the scope of the DFES 2021 analysis and is covered in a separate dedicated technology summary. There is significant uncertainty around the feasibility of using hydrogen for significant amounts of power generation in the future. As a result, hydrogen-fired peaking generation sees a wide range of outcomes across the future energy scenarios, reflecting this range of uncertainty.
Stakeholders said that future development of fossil gas-fired peaking plants could be limited due to their carbon intensity.	In the net zero scenarios, we typically assume a much less favourable environment for high carbon technologies such as fossil gas-fired peaking plants. The modelling has therefore limited the pipeline sites that go ahead to those with significantly positive development evidence in the three net zero scenarios in the near-term. In the medium-term and out to 2050, connected capacity of fossil gas-fired generation declines to zero in these three scenarios.

References:

WPD connection offer data, Capacity Market auction results and data, local authority planning portals, Nationally Significant Infrastructure Projects (NSIP) register, Embedded Capacity Register (WPD) and the results from the WPD DFES consultation events.

Hydrogen-fuelled generation in the South West licence area

Summary of modelling assumptions and results

Technology specification:

This analysis covers hydrogen-fuelled electricity generation, which has been modelled to connect to the distribution network in areas where there is the potential for hydrogen gas supply. This links to the analysis undertaken for fossil gas capacity in the South West licence area.

This technology pertains to Building Block ID number Gen_BB023 in the FES 2021 data.

Data summary for hydrogen-fuelled generation in the South West licence area:

Installed capacity (MW)	Baseline	2025	2030	2035	2040	2045	2050
Steady Progression	0	0	0	0	0	0	0
System Transformation		0	13	78	123	176	388
Consumer Transformation		0	13	78	78	123	163
Leading the Way		0	19	84	151	231	521

Summary:

- This technology considers the potential for some existing and known commercial gas and diesel generation sites to convert their generator assets to be able to run on hydrogen instead of fossil gas.
- This conversion has been modelled to occur in regions within the licence area that have been identified as potential hydrogen supply zones.
- Hydrogen supply zones were identified where there is potential for hydrogen gas network conversion or are potential future hot spots for hydrogen development, such as heavy transport fuelling hubs and industrial clusters. These include Plymouth, due to the significant maritime sector, and Bridgwater due to the presence of potential large-scale hydrogen storage in salt field basins[39].
- These supply zones were identified to convert in phases, representing the likely timescales of hydrogen supply for each zone.
- The analysis then sought to identify the relevant ESAs that fall within these potential future hydrogen supply zones. Existing natural gas and diesel sites have then been modelled to re-purpose as hydrogen-fuelled generation sites in the 2030s and 2040s.
- The South West has a significant amount of existing gas and diesel generating capacity (504 MW) along with a substantial pipeline (178 MW). Therefore, in high hydrogen scenarios, it is likely to see deployment of hydrogen-fuelled generation in the future.
- As a general consideration, the business case for hydrogen-fuelled electricity generation is likely to be challenging, with hydrogen almost certainly set to be more expensive than natural gas is today.
- However, there is strong support for the role low carbon hydrogen can play in providing flexible power generation, which is covered in the UK Hydrogen Strategy. In July 2021, the UK government published a call for evidence on ‘decarbonisation readiness’ for new power generation. It is expected that from 2030, plants would be capable of accepting 100% hydrogen.

- Hence, WPD DFES 2021 showcases a large range of possible future scenarios, representing the significant uncertainty of this technology.

Results:

Baseline (up to 31st March 2021)

- As a technology, hydrogen-fuelled generation is a future consideration, which is not currently being trialled due to a lack of hydrogen supply across the UK.
- Thus, there is currently no hydrogen-fuelled generation connected to the distribution network in the South West licence area, or nationally.
- However, there is currently 387 MW of gas-fired power generation and 117 MW of diesel generation connected to the distribution network in this licence area.
- These sites under some scenarios have the potential to convert their input fuel to low carbon hydrogen.

Near term (April 2021 – March 2025)

- There is unlikely to be any development in grid connected hydrogen-fuelled generation in the near term. This is due to gas-fired electricity generation still providing energy and flexibility to the system. In addition to this, the hydrogen supply chain is unlikely to be developed enough to allow hydrogen-fuelled generation to be viable in the near term.
- The UK Hydrogen Strategy expects the 2020s to be focussed on deploying electrolysers and scaling up long duration hydrogen storage. This aims to enable the integration of hydrogen across the wider energy system by 2030, and the availability of hydrogen as a fuel.
- Industry is anticipating the potential market opportunity for hydrogen-fuelled generation. This can be seen by engine and turbine manufacturers already selling 'hydrogen-ready' equipment.

Medium term (April 2025 – March 2035)

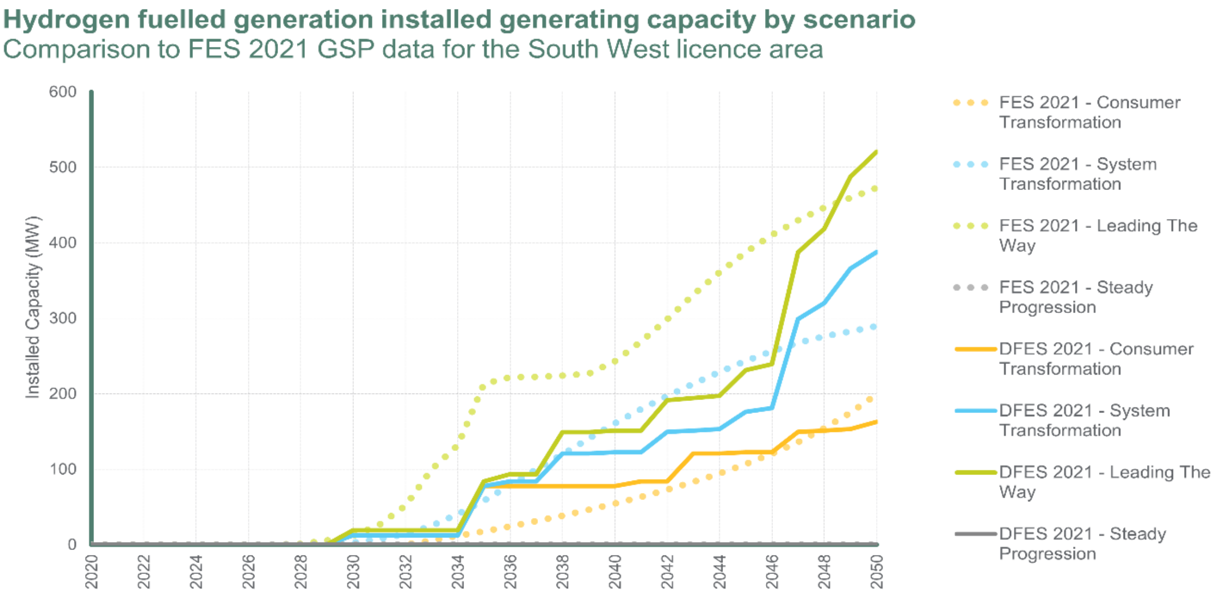
- From 2030, hydrogen-fuelled generation sites may begin to connect in regions where hydrogen is likely to be produced at scale. At a national level, these are likely to be centred around existing hydrogen trial areas, such as Teesside and Grangemouth.
- There are key sites in the South West which may be early adopters of hydrogen, including existing gas and diesel generators around Plymouth, Bristol and Bridgwater.
- Existing commercial gas and diesel sites in ESAs proximal to these areas could convert to hydrogen as soon as the early 2030s in **System Transformation** and **Leading the Way**, given the commercial landscape and national hydrogen strategy in these scenarios.
- This analysis culminates in the total hydrogen-fuelled generation capacity reaching 84 MW in **Leading the Way** and 78 MW in **Consumer Transformation** and **System Transformation** by 2035. Capacity remains at zero in **Steady Progression**.

Long term (April 2035 – March 2050)

- Existing and pipeline fossil fuel sites in identified hydrogen zones are modelled to convert to hydrogen between 2030 and 2045 in **Leading the Way**, **Consumer Transformation** and **System Transformation**.
- Sites falling outside of these zones are modelled to convert in the late 2040s under **Leading the Way** and **System Transformation** only, where hydrogen supply is more abundant.
- Under **Leading the Way**, medium-scale sites (< 50 MW) are modelled to repower with 50% more capacity, representing the most ambitious scenario for hydrogen-fuelled generation on the distribution network. This results in **Leading the Way** having the most capacity connected across the projection period (521 MW by 2050), reflecting the highest need for distributed low carbon flexibility.

- Under **System Transformation**, it is assumed that sites currently on the distribution network repower at the same capacity for hydrogen-fuelled generation, but significant capacity of hydrogen-fuelled generation in this scenario is expected on the transmission network.
- There is no hydrogen-fuelled generation capacity projected to connect under **Steady Progression**, due to limited uptake of low carbon hydrogen, while fossil gas-fired flexible generation continues to operate out to 2050.

Figure 36



Reconciliation with National Grid FES 2021:

- At an individual scenario level, the WPD DFES 2021 echoes the FES 2021 assumptions outlined at a national level.
- In FES 2021, under **Leading the Way**, hydrogen-fuelled generation experiences a surge in capacity in the 2030s; however, this is not reflected in WPD DFES 2021. This could be expected to occur in early hydrogen adopting regions, such as Teesside and Grangemouth. However, it is unlikely to apply to the South West, due to a lack of hydrogen supply in this time period.
- FES 2021 has modelled a much smoother, more gradual increase in connected capacity between 2030 and 2050, particularly in **System Transformation** and **Consumer Transformation**. In contrast, WPD DFES 2021 has modelled discrete sites to convert within potential hydrogen supply areas, resulting in a more stepped increase in capacity across the 2030s and 2040s.
- The method by which the DFES allocates project capacity results in a slightly higher overall capacity connecting under **Leading the Way** and **System Transformation**, while **Consumer Transformation** is slightly higher than FES 2021.
- These regional differences are likely due to the WPD DFES 2021 approach of repowering existing and pipeline gas and diesel sites.

Factors that will affect deployment at a local level:

- To model the connection of hydrogen-fuelled generation in the 2030s and 2040s, a spatial analysis of potential hydrogen supply areas was completed and compared to commercial baseline and pipeline fossil-fuelled generation sites.
- The identification of these hydrogen supply areas considered the location of:
  - existing hydrogen trials
  - large industrial clusters
  - proximity to the gas network
  - proximity to major roads and motorways
  - potential hydrogen storage facilities
- The location of projected hydrogen-fuelled generation sites is based on the location of existing and known commercial gas and diesel sites. This is in accordance with our engagement with National Grid ESO who said that they "expect most of the dedicated hydrogen generation to be new build (albeit located at existing sites) and optimised for peak running".

Stakeholder engagement:

As part of the WPD DFES stakeholder engagement process, Regen delivered a series of webinars with WPD in June 2021. In the webinars, the likely impact of the MCPD on commercial medium-scale diesel generation sites was considered. 83% of respondents thought that these sites would cease operation as a diesel generation site, with two-thirds thinking that they would transition to another technology, such as hydrogen-fuelled generation. This feedback has directly influenced the WPD DFES 2021 analysis for all licence areas, with the assumption made that existing and known fossil fuel sites will transition to other technologies that have lower carbon emissions, but still provide grid flexibility. For the South West licence area, 58% of respondents thought that existing commercial medium-scale diesel generation sites would transition to another technology.

Relevant assumptions from National Grid FES 2021:

Assumption number	4.1.32 – Dispatchable peaking generation
Steady Progression	Initial strong growth in unabated gas reciprocating engines and stays high as gas generation (small and large) plays an increasingly important role as flexible generation in the absence of strong growth in other technologies (e.g., storage, interconnection)
System Transformation	Initial slow growth (low deployment of gas reciprocating engines). Later strong growth in hydrogen plant to support system flexibility.
Consumer Transformation	Initial slow growth (low deployment of gas reciprocating engines). Later moderate growth in hydrogen plant to support system flexibility.
Leading the Way	Low throughout: initial growth of gas reciprocating engines is low as not aligned to decarbonisation and low long-term growth as other flexible solutions dominate in this scenario.

References:

WPD connections and offers data, WPD DFES 2021 gas, diesel and hydrogen electrolysis analysis, UK Hydrogen Strategy, consultation with ITM Power.

Diesel generation in the South West licence area

Summary of modelling assumptions and results

Technology specification:

Diesel-fuelled electricity generation, including standalone commercial diesel plants and behind-the-meter diesel back-up generators.

Technology building block: Gen_BB005 – Non-renewable engines (diesel) (non-CHP)

Data summary for diesel in the South West licence area:

Installed capacity (MW)	Baseline	2025	2030	2035	2040	2045	2050
Steady Progression	136	136	80	0	0	0	0
System Transformation		100	1	0	0	0	0
Consumer Transformation		100	1	0	0	0	0
Leading the Way		1	0	0	0	0	0

Summary:

- The South West licence area has a number of existing operational diesel engines. This is a mixture of both standalone commercial diesel generation sites and behind-the-meter back-up generators co-located with larger energy user buildings.
- There are no diesel sites with accepted connection offers in the licence area.
- Unabated diesel generation has a very limited lifespan in the licence area, due to being at odds with net zero emissions targets and the stringent emissions level requirements of relevant environmental permitting.
- As a result, all diesel capacity disconnects from the network in all scenarios by 2034.
- **Leading the Way** sees the most rapid disconnection of diesel capacity in the licence area, with all sites decommissioning within the early 2020s.

Modelling assumptions and results:

Baseline

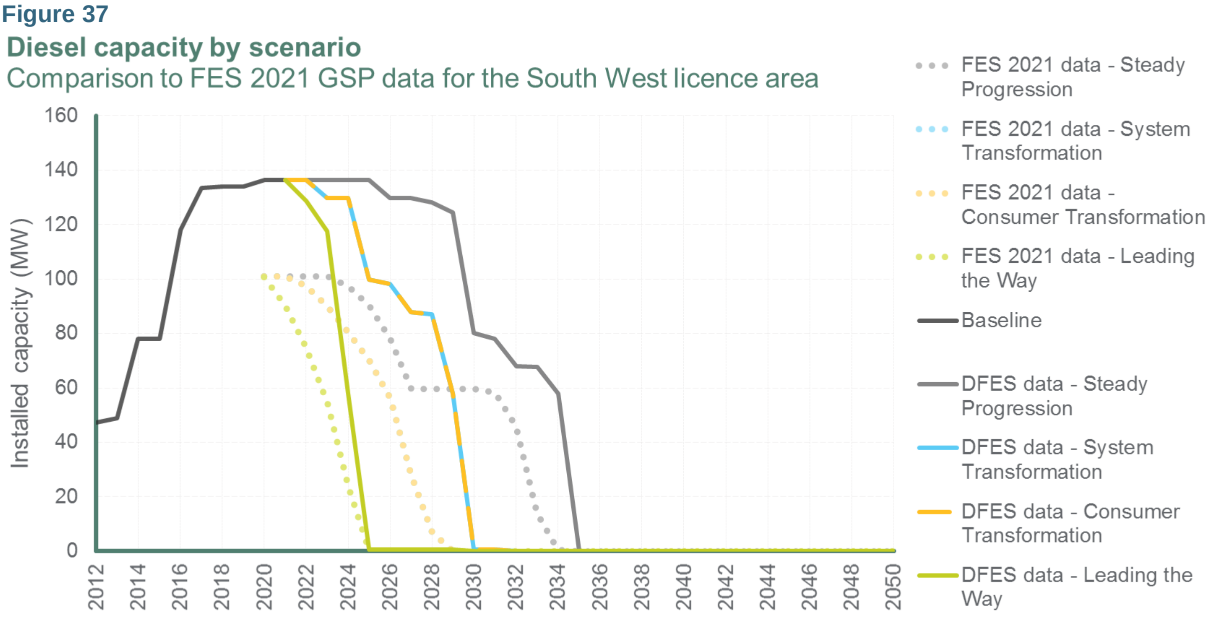
- There are 26 diesel fuelled generation sites in the South West licence area, totalling 136 MW.
- This is a mixture of larger commercial-scale diesel plants (8 sites, 92 MW) and smaller back-up diesel generators (18 sites, 44 MW).
- The larger plants have historically targeted commercial electricity network reserve services (such as Short Term Operating Reserve (STOR) or the Capacity Market).
- The smaller back-up generators are located onsite at a number of larger energy consumer buildings such as water industry sites, supermarkets, national rail sites and hospitals.

Projections (April 2021 to March 2050)

- There are no pipeline sites with an accepted connection offer in the licence area.
- As a fossil fuel, the operation of unabated diesel fired electricity generation is considered to contribute carbon emissions. Therefore, both the continued operation of existing diesel plants and the development of new plants are at odds with UK net zero targets.

- In addition to this, a piece of EU legislation known as the Medium Combustion Plant Directive (MCPD) has been passed into UK law. This requires plants to adhere to stringent air quality limits through environmental permitting, unless they only operate for a few hours per year (i.e. back-up generators only).
- Unabated commercial diesel generation falls within this regulation and will therefore no longer be able to operate from 2025[40] without exhaust abatement technologies (such as catalytic reduction technology). This type of companion technology is unlikely to be financially viable in the near term.
- The DFES analysis therefore focuses on the decommissioning of all baseline diesel generators within the licence area. Between now and the mid-2030s, depending on the scenario, the decommissioning model considers the following factors:
    - The type of diesel site (standalone or back-up)
    - The year it was installed
    - How each scenario reflects environmental permitting requirements under the MCPD and progress towards net zero targets.
- This results in all diesel generation capacity being decommissioned from the distribution network in the licence area. This removal of all diesel generation happens by 2025 in **Leading the Way**, by 2030 in **Consumer Transformation** and **System Transformation** and by 2035 in **Steady Progression**.
- Following feedback from engaging sector stakeholders, this decommissioning is based on the assumption that standalone flexibility moves to lower carbon alternatives. These include electricity storage, demand side response and cleaner 'dispatchable' generation technologies such as anaerobic digestion.
- There is a short-term consideration that low-carbon diesel or biodiesel could still play a role for back-up generators, as a result this extends the operation of existing plants out to the 2030s specifically under **Steady Progression**.

Figure 37



Reconciliation with National Grid FES 2021:

Results in this section relate to the FES 2021 data as reported for the Building Block ID number Gen_BB005:

- The current installed capacity of diesel generation in the South West licence area is c.30 MW higher in the WPD DFES data than in the FES 2021 publications. The reason for this variance is unclear.

- The DFES projections align to the FES assumptions that all unabated diesel capacity is decommissioned from operating on the distribution network by:
    - 2025 in **Leading the Way**
    - 2030 in **Consumer Transformation** and **System Transformation**
    - 2035 in **Steady Progression**

Factors that will affect deployment at a local level:

As the analysis solely focuses on decommissioning existing known baseline sites, the spatial distribution references site location of the 26 existing diesel generation sites.

Stakeholder feedback overview:

Diesel-fuelled generation	
Your comments to us	Our response
When discussing the future of diesel-fuelled generation with stakeholders, the majority of respondents fed back that diesel-fuelled generation sites impacted by air quality regulations would transition to another technology. A minority felt sites would simply fully decommission instead.	Existing diesel-fuelled generation sites will be used as distribution factors for other technologies such as battery storage and hydrogen-fuelled generation, where feasible.

References:

WPD connection offer data, Environment Agency, Regen consultation with local stakeholders and discussion with asset owners.

Waste (incineration) in the South West licence area

Summary of modelling assumptions and results

Technology specification:

This analysis covers Energy from Waste (EfW) technologies, including incineration and Advanced Conversion Technologies (ACT).

This technology pertains to Building Block ID number Gen_BB011 in the FES 2021 data.

Data summary for waste (incineration) in the South West licence area:

Installed capacity (MW)	Baseline	2025	2030	2035	2040	2045	2050
Steady Progression	226	244	278	278	278	278	278
System Transformation		244	255	178	178	170	168
Consumer Transformation		244	255	178	178	170	168
Leading the Way		244	178	170	168	163	44

Summary:

- Significant capacity of unabated incineration generation is at odds with net zero targets, due to the level of associated carbon emissions. Hence, it is assumed that incineration capacity reduces after 2030 in **Leading the Way**, **Consumer Transformation** and **System Transformation**, as older facilities reach the end of their operational lifetime.
- In **Consumer Transformation** and **System Transformation**, developments in CCUS technology are expected to enable most EfW capacity to remain connected and operational.
- ACT gasification plants (which accounts for 15.6 MW across the scenario period) have lower associated carbon emissions, and any residual emissions can be abated.
- All ACT sites on WPD's network connected in the last decade and are not expected to decommission before 2050.

Modelling assumptions and results:

Baseline (up to 31st March 2021)

- There are nine waste sites in the WPD connection database totalling 226 MW.
- This comprises one ACT site (15.6 MW) and eight incineration sites, totalling 210.6 MW.
- The most recent site to connect was a 44.4 MW incinerator in Bristol in September 2019.
- The largest operational site is the Severnside Energy Recover Centre (48 MW)

Near term (April 2021 – March 2025)

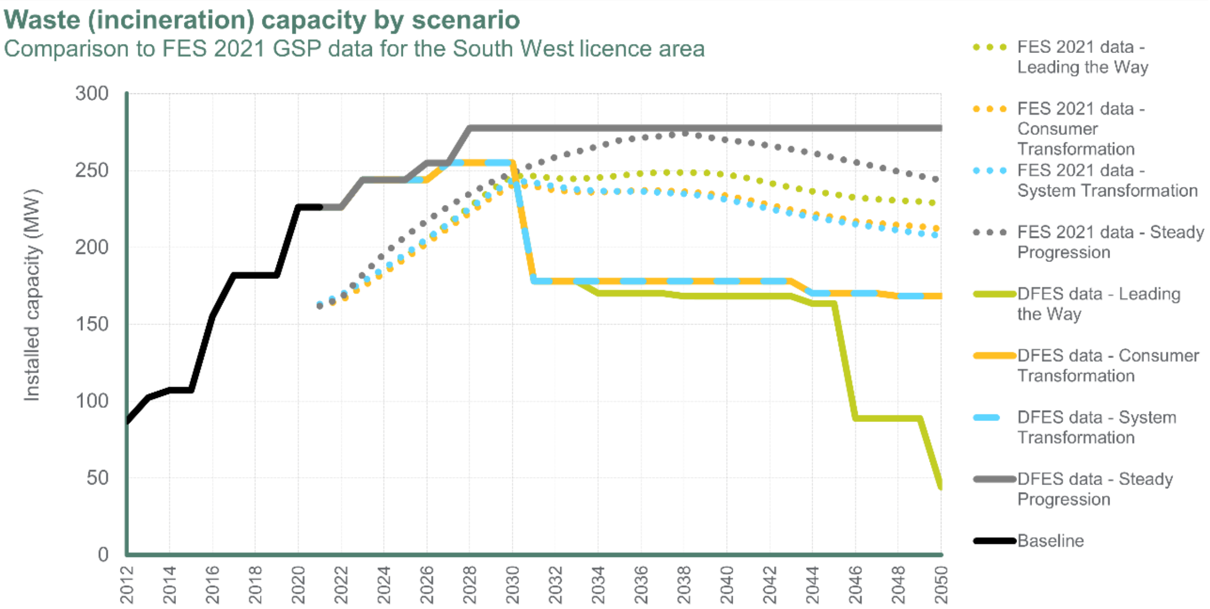
- There are four pipeline incineration sites in WPD's connection database, totalling 51.5 MW.
- Three of the sites have planning permission granted (2012, 2015 and 2021).

- Based on analysis of REPD, historically incineration plants take 4.7 years from gaining planning permission to becoming operational. As a result, these sites connect between 2022 and 2026, depending on the scenario.
- The other incineration site (22.7 MW) has no planning information; hence, it is only modelled to connect in **Steady Progression**.

Medium and long term (April 2025 – March 2050)

- No additional sites of any EfW technology have been projected to connected beyond the pipeline in any scenario, as unabated EfW is at odds with net zero targets, due to the level of associated carbon emissions.
- For ACT:
  - All ACT sites on WPD's network have connected in the last decade and are not expected to decommission before 2050.
  - No further ACT capacity is modelled to connect due to difficulties in making the technology viable, and subsequent lack of activity in the sector. This is reflected by the lack of pipeline projects.
- For incineration:
  - All EfW incineration sites are modelled to stay online until at least 2030.
  - The medium- and long-term projections are determined by the end-of-life decommissioning of existing sites (both currently operational and sites in the pipeline).
  - The operational life of an EfW incineration facility is typically between 20 and 30 years[41]; however, the connection agreement may not be relinquished immediately. EfW incineration facilities have been modelled to disconnect after 30 years in **Leading the Way** and 40 years in **Consumer Transformation** and **System Transformation**, in order to model the operational life range and the potential delay between decommissioning and relinquishing a connection agreement.
  - To explore the worst-case distribution network conditions, no sites are modelled to come offline in **Steady Progression**.

Figure 38



Reconciliation with National Grid FES 2021:

Results in this section relate to the FES 2021 data as reported for Building Block ID number Gen_BB011.

- WPD connections data has 226 MW of capacity connected to their distribution network in the South West licence area, which is significantly higher than the FES 2021 baseline. This discrepancy may be caused by WPD DFES' inclusion of all generators with valid connection agreements, regardless of absent supply contracts.
- The WPD DFES 2021 assumptions align with FES 2021; however, the results may differ due to local spatial distribution.
- The FES 2021 data shows a continued increase out to 2040, before capacity reduces; however, WPD DFES 2021 has modelled the connection of the four pipeline sites in the near term and then the decommissioning of sites from 2030 onwards. This results in a staggered projection, which more realistically represents the likely reduction in capacity.

Relevant assumptions from National Grid FES 2021:

Assumption number	4.1.11 - Unabated Biomass and Energy from Waste (EfW) generation
Steady Progression	No significant change in waste management from society; leaving waste available as a fuel source for unabated generation.
System Transformation	Less waste to burn in general due to a highly conscious society adapting to low waste living.
Consumer Transformation	Less waste to burn in general due to a highly conscious society adapting to low waste living.
Leading the Way	Less waste to burn in general due to a highly conscious society adapting to low waste living.

References:

WPD connection offer data, Renewable Energy Planning Database, Regen consultation with local stakeholders and discussion with developers.

Other generation in the South West licence area

Summary of modelling assumptions and results

Technology specification:

All operational generation sites and accepted connection offers that are unidentified as one of the generation technology types in-scope of the DFES 2021 analysis.

Data summary for other generation in the South West licence area:

Installed capacity (MW)	Baseline	2025	2030	2035	2040	2045	2050
Steady Progression	21.7	22.3	22.3	22.3	22.3	22.3	22.3
System Transformation		22.3	22.3	22.3	22.3	22.3	22.3
Consumer Transformation		22.3	22.3	22.3	22.3	22.3	22.3
Leading the Way		22.3	22.3	22.3	22.3	22.3	22.3

Summary:

- There are 24 sites (totalling 22 MW) connected to the distribution network in the South West licence area that have no identifiable technology type.
- In some cases, this is because of a lack of available information, meaning the connected site could not be located. In other cases, it is because the sites are likely thermal or fossil fuel generators, whose fuel type cannot be confidently identified.
- There are 5 additional sites with unclear technology types in the South West licence area with an accepted network connection offer, totalling c. 600 kW.
- The projected connection year for these sites is the same across all scenarios. They are projected to connect 3 years after accepting a connection offer, meaning all pipeline sites are projected to connect before 2024.

Reconciliation with National Grid FES 2021:

There is no equivalent technology type in National Grid FES 2021 to be compared against.

References:

WPD connection agreement and offer data.

[24] FES Modelling Methods 2021
[25] Smart Export Guarantee (SEG)
[26] Social Grade, National Readership Survey
[27] Geothermal Electricity Generation, Challenges, Opportunities and Recommendations
[28] GEL confirms highest global concentration of lithium in geothermal fluid at its United Downs site
[29] United Downs Deep Geothermal Power Project
[30] Four new geothermal projects announced for Cornwall, UK
[31] Geothermal potential in the UK and Cornwall
[32] Future Geothermal Power & Heat sites
[33] Contracts for Difference for Low Carbon Electricity Generation
[34] Benefits of floating offshore wind to Wales and the South West
[35] Biomass in a low carbon economy, CCC
[36] Is there still a future in AD plants for UK farmers?, Farmers Weekly
[37] Environment Bill sets out vision for a greener future
[38] Agricultural Land Classification
[39] A review of onshore UK salt deposits and their potential for underground gas storage
[40] Medium combustion plant: when you need a permit
[41] Energy from waste: a guide to the debate

Results and assumptions

Energy storage technologies

Battery storage in the South West licence area

Summary of modelling assumptions and results

Technology specification:

Battery storage, comprising four business models:

- **Standalone network services –** typically multiple megawatt scale projects that provide balancing, flexibility and support services to the electricity network.
- **Generation co-location** – typically multiple megawatt scale projects, sited alongside renewable energy (or occasionally fossil fuel) generation projects.
- **Behind-the-meter high-energy user** – typically single megawatt or smaller scale projects, sited at large energy-user operational sites to support on-site energy management or to avoid high electricity cost periods.

  These 3 business models combine to form the FES building block **Batteries Srg_BB001**

- **Domestic batteries –** typically 5-20 kW scale batteries that households buy to operate alongside rooftop PV or to provide backup services to the home. This business model aligns with the FES building block **Domestic Batteries (G98) Srg_BB002**.

The analysis also considered other forms of electricity storage, Srg_BB003 (pumped hydro), Srg_BB004 (other technologies, liquid air, compressed air). However, no evidence was found for these technologies seeking to connect on the distribution network in the licence area. The building block Srg_BB005 (Vehicle-to-Grid) was not within the scope of the analysis.

Data summary for battery storage in the South West licence area:

Installed power capacity (MW)		Baseline	2025	2030	2035	2040	2045	2050
Standalone network services	Steady Progression	47	85	87	89	91	92	94
	System Transformation		93	120	126	133	153	175
	Consumer Transformation		165	184	206	237	273	314
	Leading the Way		165	194	229	270	319	376
Generation co-location	Steady Progression	3	3	4	8	9	16	17
	System Transformation		44	58	63	72	75	79
	Consumer Transformation		44	64	73	110	120	131
	Leading the Way		44	81	98	127	138	142

Behind-the-meter high-energy user	**Steady Progression**	0.5	6	9	10	12	14	15
	System Transformation		12	17	20	24	28	30
	Consumer Transformation		18	25	30	60	70	74
	Leading the Way		29	41	49	60	70	74
Domestic batteries	**Steady Progression**	0.12	3	3	8	9	27	61
	System Transformation		15	24	34	44	109	129
	Consumer Transformation		32	62	94	158	299	483
	Leading the Way		40	79	145	245	415	756

Summary:

- The South West licence area has 50 MW of operational battery storage capacity, 27 MW of which connected in 2020.
- The licence area also has a significant pipeline of battery storage projects with accepted connection offers; 48 projects totalling c. 555 MW.
- The licence area has good potential for long-term growth in connected storage capacity. This is due to:
  - Good potential for distributed renewable energy deployment, enabling co-location
  - A notable number of non-domestic properties with the potential for behind-the-meter batteries across WPD's network
  - A strong potential capacity for domestic rooftop solar by 2050, enabling a notable capacity of domestic batteries to be co-located in homes.
- Overall battery storage capacity in 2050 in the South West licence area ranges from 188 MW in **Steady Progression** to 1.4 GW in **Leading the Way**.

Modelling assumptions and results:

Baseline

- There are 42 sites totalling 50 MW currently connected in the South West licence area, all of which have come online since 2016.
- This comprises:
  - 3 standalone battery projects totalling 47 MW
  - 2 generation co-location projects totalling 2.6 MW
  - 7 behind-the-meter high-energy user projects totalling 480 kW
  - 30 domestic-scale batteries, totalling 119 kW

Near term (April 2021 – March 2025)

- The South West licence area has a notable pipeline of battery storage sites with accepted connection offers: 44 projects totalling 555 MW.
- This comprises:
  - 15 standalone battery sites, totalling 365 MW
  - 13 generation co-location battery sites, totalling 190 MW
  - 6 behind-the-meter high-energy user batteries, totalling 438 kW
  - 14 domestic batteries, totalling 54 kW.
- Within this pipeline, 3 projects have individual capacities of c.50 MW or higher

- Reviewing the development activity of these projects:
    - 10 sites (179 MW) have secured planning approval recently (2017-2021)
    - 2 sites (39 MW) have successfully pre-qualified in recent Capacity Market auctions
    - 2 sites (26 MW) were refused planning or were rejected in recent Capacity Market auctions
    - For 16 sites (370 MW) no development information could be found.
- The planning history and capacity market activity of the pipeline sites are key weighting factors that determine when these sites are modelled to connect under the four scenarios.
- By 2025, connected battery storage capacity in the South West licence area is highest (278 MW) under **Leading the Way** and lowest (97 MW) under **Steady Progression**.

Medium term (April 2025 – March 2035)

- The four business models for battery storage are modelled separately, and potential deployment in the licence area is driven by different factors.
- Standalone storage accounts for a significant proportion of the existing or known near-term storage pipeline capacity and this business model continues to see an increase across all scenarios by 2035.
- Generation co-location capacity sees a moderate uptake in the South West licence area, due to seeing a moderately lower combined ground mounted solar PV and onshore wind development by 2035, when compared to other licence areas across all scenarios.
- The South West licence area has a notable number of non-domestic properties with the potential for a battery, thus the uptake of behind-the-meter storage projects in the licence area increases in all scenarios by 2035. This reflects feedback from stakeholders that high-energy users, such as industrial customers, could drive electricity storage deployment in the near and medium term.
- The licence area has significant potential for domestic battery deployment in the medium term, with well over one million homes in the licence area and significant domestic scale rooftop PV deployment projections. Significant uptake of domestic storage is delayed until the longer term however, reflecting stakeholder feedback that domestic storage will be the business model with the lowest uptake in the near-to-medium term.
- By 2035 total battery storage capacity in the licence area reaches 521 MW under **Leading the Way** and 114 MW under **Steady Progression**.

Long term (April 2035 – March 2050)

- In the long term, the biggest increase in projected battery storage capacity is seen in **Leading the Way**, reflecting strong potential across all four storage business models.
- The **Steady Progression** scenario sees the lowest overall storage deployment in the licence area. This reflects a lesser need for electricity system flexibility, a lower renewable energy adoption and ongoing use of fossil fuel generation. This environment has been reflected in the longer term out to 2050, across all storage business models.
- Installed battery storage capacity in the licence area reaches c.1.3 GW in **Leading the Way** and 188 MW in **Steady Progression** by 2050.

Figure 39

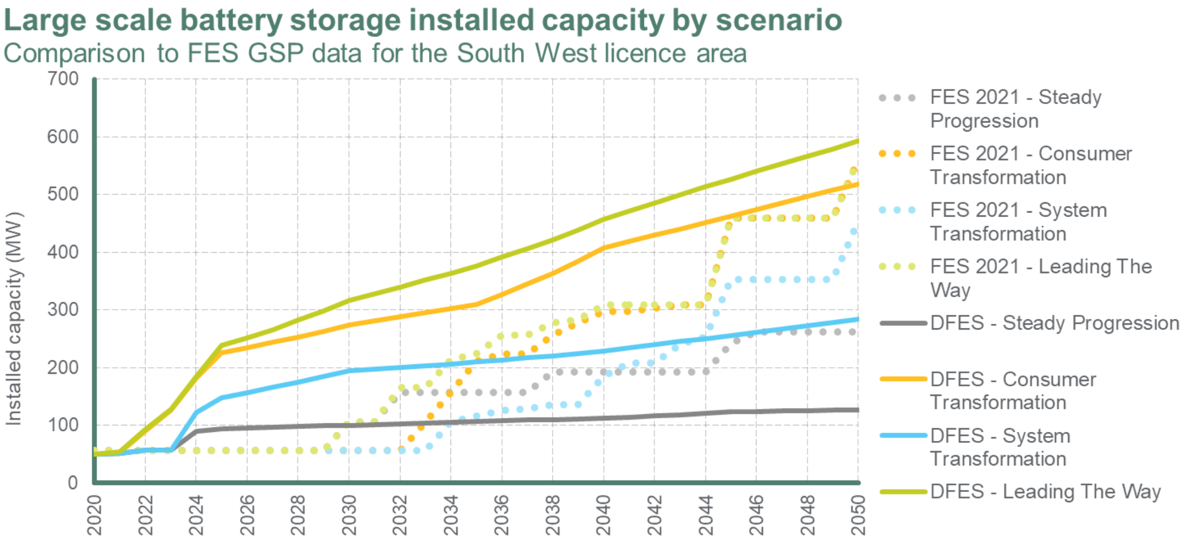
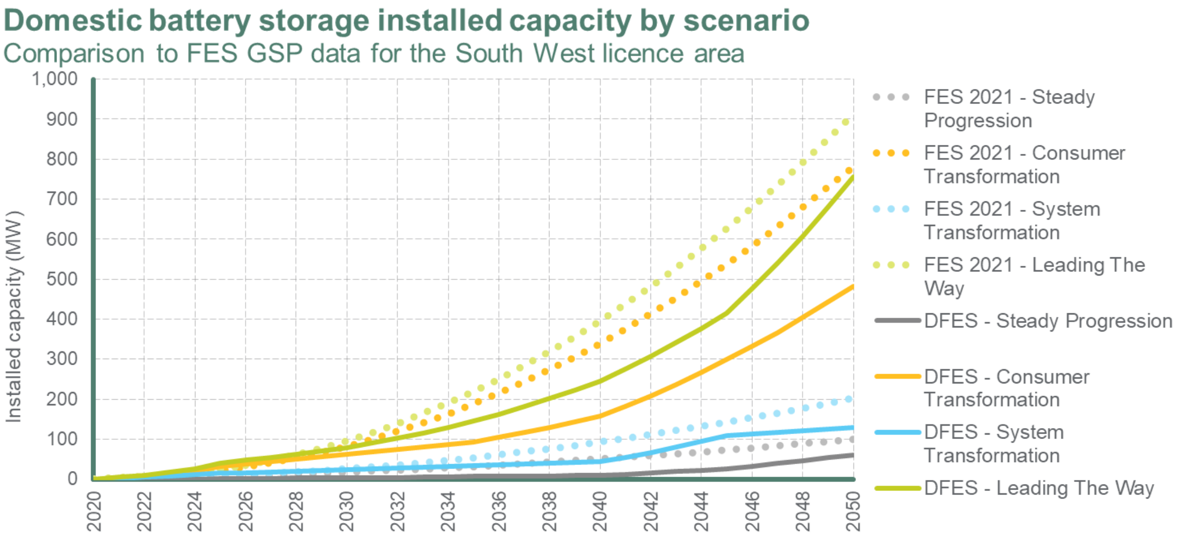


Figure 40



Reconciliation with National Grid FES 2021:

Results in this section relate to the FES 2021 data as reported for the Building Block ID number Srg_BB001 and Srg_BB002:

- The 2021 baselines in both the FES 2021 and WPD DFES 2021 are aligned for the South West licence area.
- Reflecting analysis of the large near-term pipeline, the WPD DFES 2021 projections are notably higher than the FES 2021 projections in the 2020s and 2030s.
- The FES 2021 reconciles more closely to the WPD DFES 2021 projections by 2050.
- Both the WPD DFES 2021 and FES 2021 consider **Leading the Way** and **Consumer Transformation** as the scenarios that reflect the highest need for distributed storage capacity by 2050.
- Similarly, by 2050, both the WPD DFES 2021 and FES 2021 model **Steady Progression** as the scenario with the lowest potential need for battery storage across the analysis period.

- The FES 2021 projections have moderately higher domestic storage projections than the WPD DFES 2021. The DFES has aligned to the projected uptake of rooftop solar PV in the region.

Factors that will affect deployment at a local level:

- The spatial distribution of new battery storage projects in the near and medium term is based on the location of the pipeline sites.
- In the longer term, spatial distribution varies according to the four battery storage business models used in the modelling. These local factors are:
  - **Standalone:** Developable land proximate to the 33kV and 132kV electricity network.
  - **Generation co-location:** Proximity to existing and future ground mounted solar PV and onshore wind projects within the licence area.
  - **Behind-the-meter high-energy user:** Proximity to industrial estates and commercial buildings that could be suitable for battery storage installations.
  - **Domestic batteries:** Domestic dwellings with rooftop PV as projected in the DFES.

Relevant assumptions from National Grid FES 2021:

Assumption number	4.2.24 - Level of installed capacity of (non-domestic) storage technologies with a duration of less than 2 hours (e.g. batteries)
Steady Progression	Moderate levels of flexibility requirements encourage new storage. Not as much deployed compared to other scenarios.
System Transformation	Not as much deployed compared to other scenarios due to high use of hydrogen within this scenario.
Consumer Transformation	High levels of variable clean generation and flexibility requirements encourage new storage technologies to emerge.
Leading the Way	Even higher levels of flexibility requirements encourage new storage technologies to emerge at distributed and transmission levels.

Assumption number	4.2.25 - Level of installed capacity of (non-domestic) storage technologies with a duration of between 2 and 4 hours (e.g. medium batteries, compressed or liquid air storage)
Steady Progression	Lower flexibility requirements means that this technology does not come forward at the volumes seen in the other scenarios.
System Transformation	Moderate levels of flexibility requirements encourage new storage. Not as much deployed compared to other scenarios due to high use of hydrogen within this scenario.
Consumer Transformation	Flexibility requirements encourage new storage.
Leading the Way	High levels of flexibility requirements encourage new storage.

Stakeholder feedback from the consultation events:

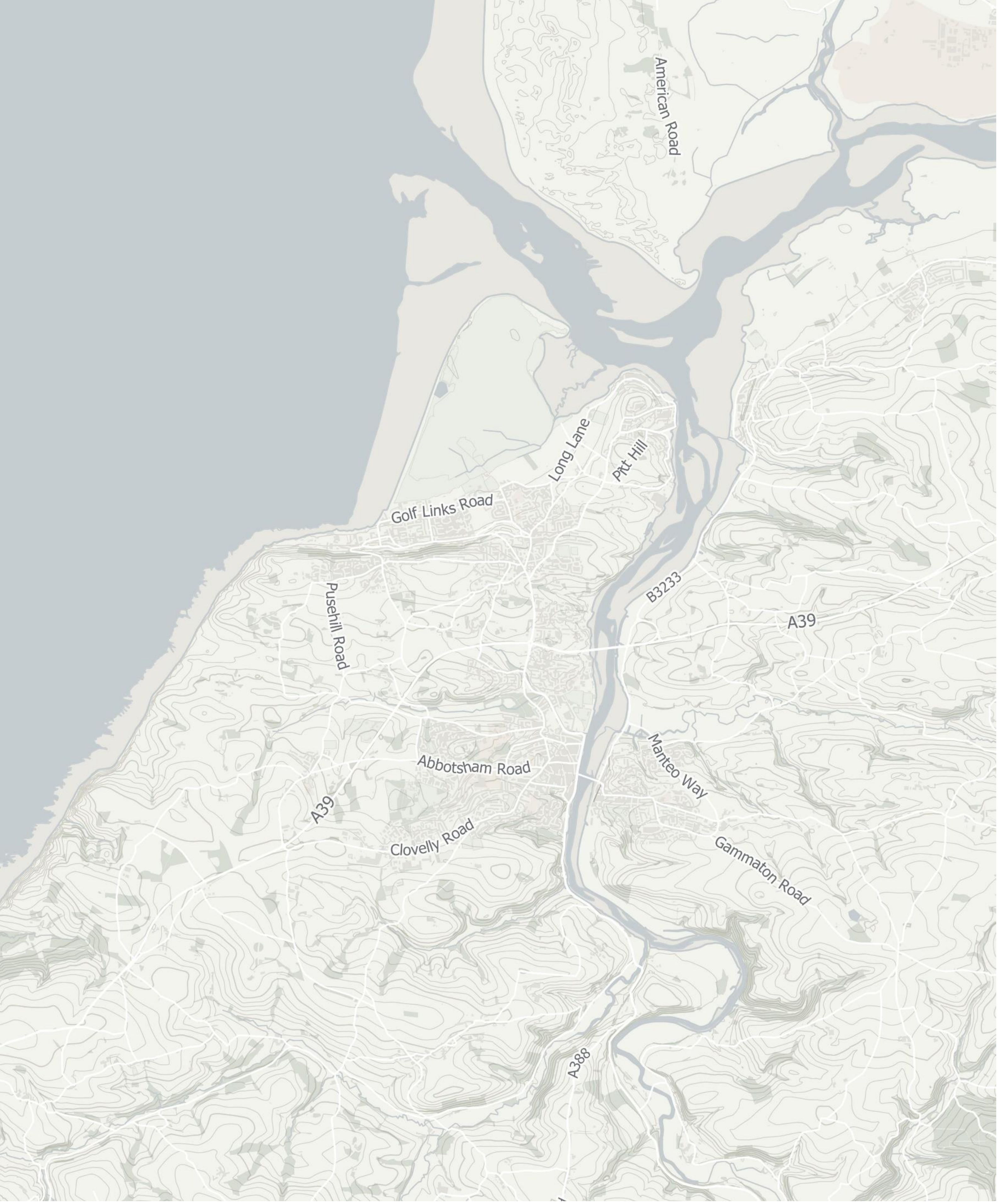
Battery storage	
Your comments to us	Our response
Stakeholders felt that electricity storage co-located with generation would be the business model with the biggest increase in capacity, followed by standalone storage projects providing grid services. Domestic electricity storage was seen as having less potential.	We use existing and potential renewable generation sites as distribution factors for future storage capacity, alongside the proximity to 33 kV and 132 kV networks. We have focussed the uptake of domestic batteries towards the longer term.
You asked whether there was much development of battery storage co-located with renewable energy generation.	The DFES specifically models co-located storage as one of the four business models for energy storage, and as such renewable generation is a key factor in the location of future energy storage.
Some stakeholders pointed out that in a heavily decarbonised electricity grid, energy storage providing system inertia could be another key revenue stream.	We are aware of these types of power-quality services, and they are one of the factors and services that underpin the 'Standalone Grid Services' business model. We accept that other business models may also have this as a revenue stream.

References:

WPD connection offer data, the Renewable Energy Planning Database, various local authority online planning portals, EMR Delivery Body Capacity Market registers.

Distribution Future Energy Scenarios 2021

Results and assumptions reports have been published for all four WPD licence areas and are available on the WPD DFES website, along with interactive maps and data download options.



regen
transforming energy

WESTERN POWER DISTRIBUTION
Serving the Midlands, South West and Wales