ARUP

Isle of Man - Future Energy Scenarios

Executive Summary
July 2021

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Isle of Man

The Roadmap to a zero carbon island

A clear roadmap is required to fully understand how the existing electricity network can be transitioned into a low or zero carbon system.

The Isle of Man (IoM) Government has legislated to reduce its greenhouse gas (GHG) emissions to net zero by 2050.

To achieve this, a clear roadmap is required to enable the transition through greater use of renewable technologies and phasing out of fossil fuels, while maintaining a reliable, resilient and affordable power supply network.

Arup is assisting the IoM government in developing a set of future scenarios for the generation of electricity on the island.

These plans are consistent with the aim to achieve 75% generation from renewable or carbon neutral sources by 2035, and achieve net zero emissions by 2050.

Our team has assessed, at a high level, the network implication of four transition scenarios, and the associated financial considerations for each scenario.

Additionally, we have also assessed an ambitious scenario, underpinned by large-scale offshore wind development, at a high level.

94%

of the electricity generated on island comes from CCGT in 2019.

200,000

tonnes of CO2 equivalent emissions from energy supply in 2018.

75%

target for power generation from renewable or carbon neutral sources by 2035.

Net zero

emissions from all sectors, including electricity, by 2050.

Managing future growth in electricity demand in a carbon neutral way

The electrification of heating and the electrification of personal transport will see peak demand increase from approximately 2025.

Electricity demand is expected to increase in future years, driven mainly by electrification of heat and the uptake of electric vehicles.

Despite energy efficiency improvements helping to reduce peak demand requirements in the short term, it is expected that the electrification of heating and personal transport will see peak demand and annual demand increase from approximately 2025.

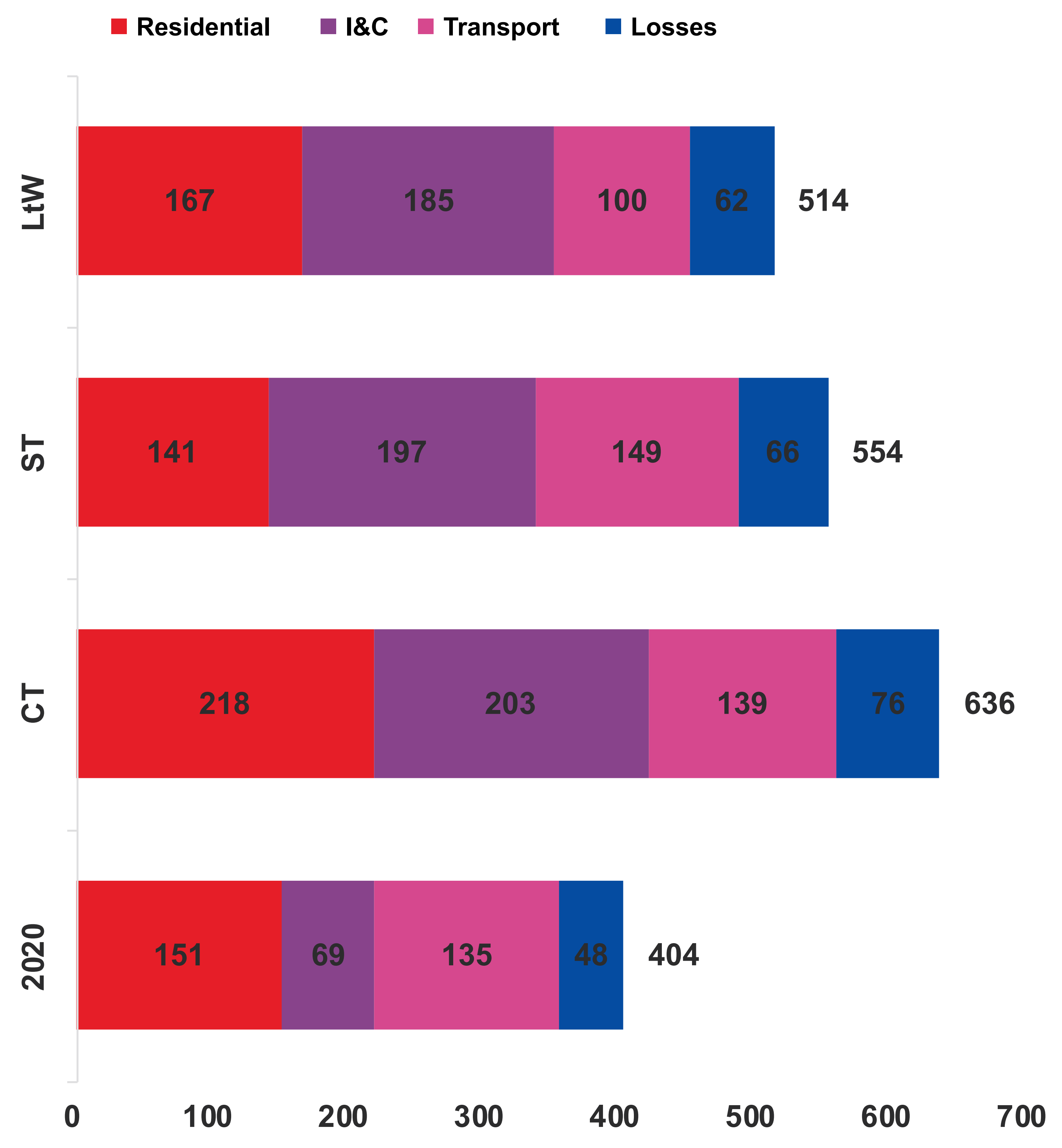
To help understand how electricity demand could evolve in the future, we have developed three distinct scenarios – (1) consumer transformation, (2) system transformation and (3) leading the way. These scenarios mirror the assessments undertaken by National Grid for Great Britain.

A market led by 'consumer transformation' towards the use of electric vehicles and electric heating will see the fastest and largest increase in peak demand – up an estimated 63% between 2019 and 2050 and to a peak demand of 131 MW. Annual demand is expected to reach 636 GWh by 2050 in this scenario.

However, by developing and adopting 'leading the way' strategies, peak demands could be significantly lowered by achieving maximum energy efficiency gains across all sectors, and increased reliance on public transport or 'active' travel.

Our calculations and predictions suggest a 'leading the way' approach could lead to a smaller increase, with peak demand reaching 106 MW by 2050, an increase of 33% from 2019. Annual demand in this scenario is expected to reach 514 GWh by 2050.

Estimated annual electricity demand in 2050 and 2020 (GWh)



The Future Energy Scenarios for the Isle of Man

Arup has developed four electricity generation scenarios for the IoM, consistent with the 2050 target. An additional offshore wind focused scenario has also been assessed.

The key points are:

- Each scenario uses varying levels of onshore wind/ offshore wind, biomass, solar power and storage technologies alongside interconnectors which provide resilience and security of supply.
- Two of the four scenarios also have varying levels of behind-the-meter (decentralised) generation in the form of solar power.
- The generation from biomass is expected to decreases over time as interconnector capacity increases across all scenarios.
- In each scenario carbon emissions decline significantly and the IoM reaches its net zero target by 2045.
- The vast majority of the emission reductions happen by 2035, driven mainly by the retirement of the existing diesel and gas-fired power plants.
- The faster than anticipated emissions reduction may make it possible to delay some investment decisions by delaying the retirement of the existing gas-fired plant. However, this is dependent on the quantity of hydrogen in the future gas grid and the compatibility of the existing plant to accept hydrogen blended gas.
- The additional Scenario 5, premised on large scale offshore wind development, indicates that whilst there are economic and societal benefits for the IoM, there are commercial and regulatory challenges that also need addressing.

£1.07 – £1.8 billion
estimated range of total cost across the four scenarios over the transition period.

8 – 58%
range of the island's power demand met by on-island generation across scenarios 1-4.

287 – 934 MW
range of total installed capacity across scenarios 1-4.

112 MW
maximum behind the meter (decentralised) installed capacity of solar power in scenario 4.

N-1
level of resilience in scenarios 1-3, allows the island's power demand to be met despite the loss of single largest generators.

N-2
level of resilience in scenario 4, allows the island's power demand to be met despite the loss of two largest generators.

Scenario 1

The renewables in scenario 1 enable 20% of the annual demand to be met from on-island generation by 2050.

Timeline

– 2028 - 28MW of biomass becomes operational as diesels retire.

– 2035 - Biomass comprises more than half of on-island installed capacity.

– 2040 - New, single 140 MW interconnector is introduced at the end of 2040 as the existing 60 MW interconnector ends use (option to bring forward in the timeline or extend the existing interconnector or CCGT's asset life.)

– 2050 - 60% on-island renewable installed capacity reached through Biomass (38%), interconnector (41%), Solar (13%), offshore wind (5%), energy storage (3%).

Resilience

N-1

island's power demand can be met despite the loss of single largest generator.

Estimated Cost

£1.49bn

estimated total cost over the transition period.

Equates to an estimated

£707m

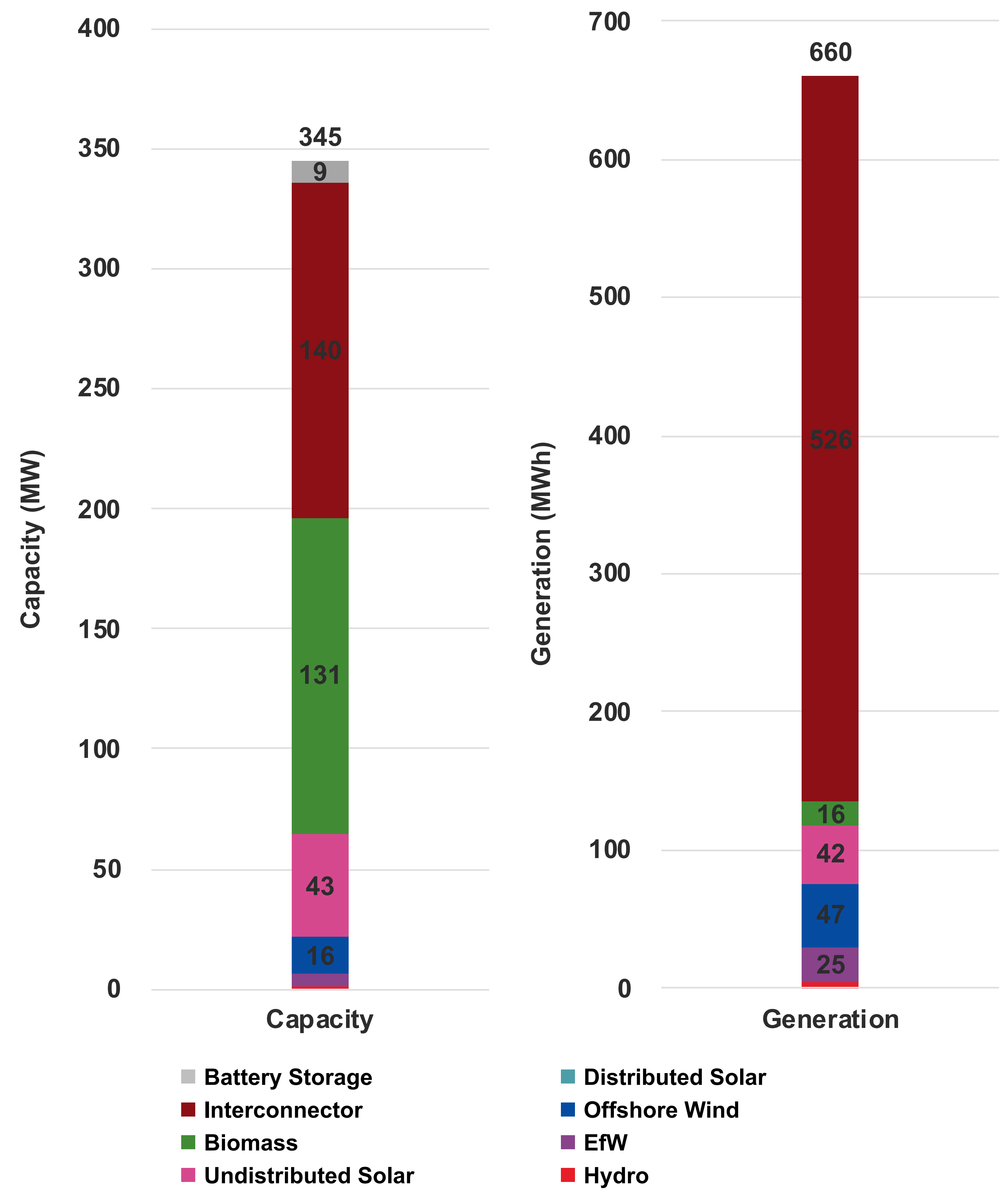
in Net Present Value terms.

On-island Generation

20%

annual power demand met through on-island generation by 2050.

Projected Installed Capacity and Generation Mix by 2050



Scenario 2

Interconnectors dominate scenario 2, with more than 90% of annual demand met by imports from GB.

Timeline

– 2028 – Diesels retire and a new 140 MW interconnector becomes operational by 2028.

– 2030 - IoM becomes a net importer of electricity

– 2031 - CCGT retires and 39 MW of biomass becomes operational by the end of the year.

– 2041 - A second new 140 MW interconnector becomes operational as existing 60 MW interconnector retires.

– 2050 – Approximately 20% on island renewable capacity, including biomass.

Resilience

N-1

island's power demand can be met despite the loss of single largest generator.

Estimated Cost

£1.4bn

estimated total cost over the transition period.

Equates to an estimated

£663m

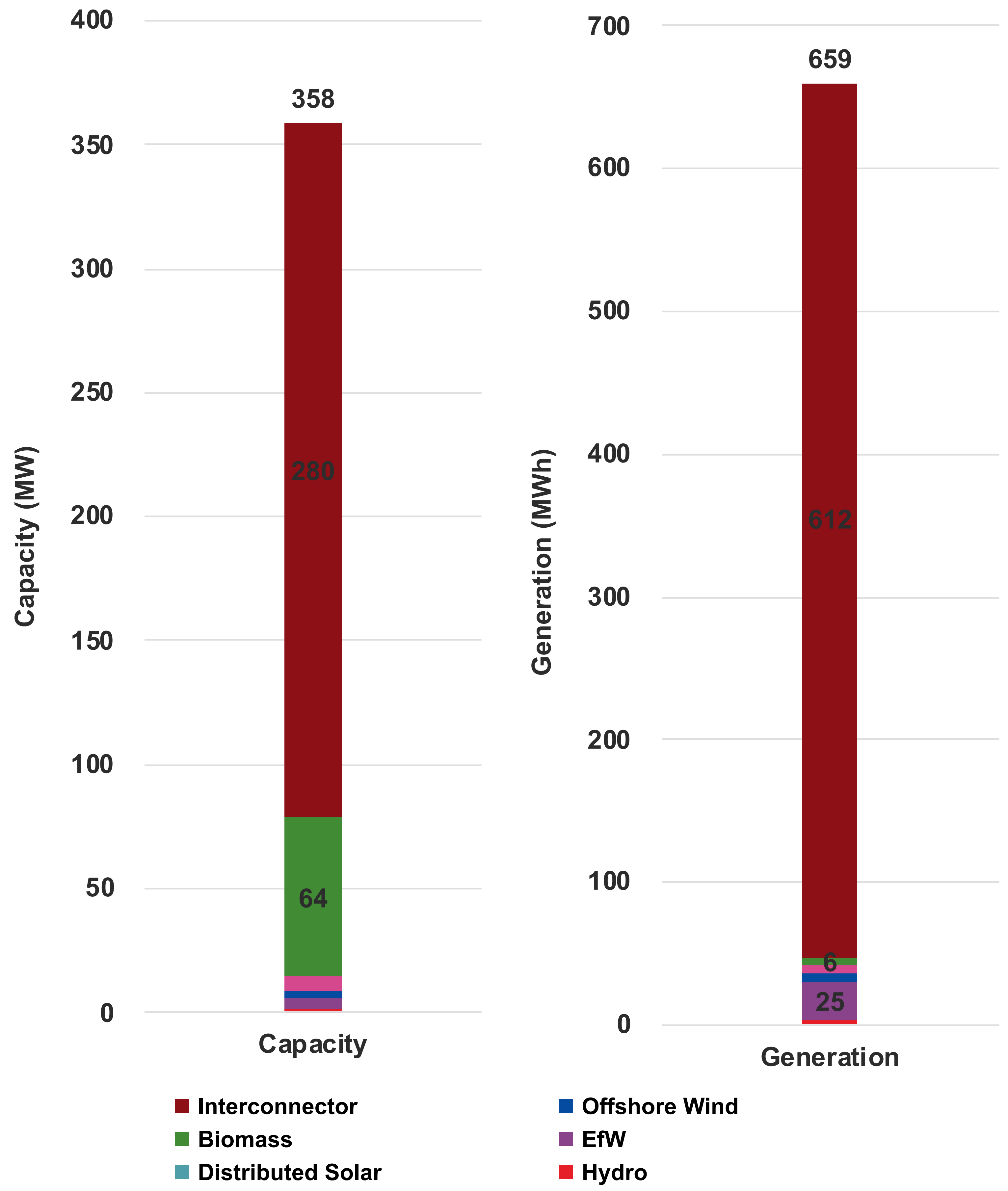
in Net Present Value terms.

On-island Generation

8%

annual power demand met through on-island generation by 2050.

Projected Installed Capacity and Generation Mix by 2050



Scenario 3

Similarly in Scenario 3, 90% of the annual demand is met by imports from GB, but with less interconnector capacity.

Timeline

- 2028 - Diesels retire and a new 140 MW interconnector becomes operational.
- 2031 - CCGT retires by end of year and 39 MW of biomass becomes operational to maintain resilience levels
- 2040 – Biomass capacity continues to increase with increasing peak demand, reaching 64 MW by 2040 to provide resilience
- 2050 - Approximately 30% on-island renewable capacity, including biomass, solar and energy from waste.

Resilience

N-1

island's power demand can be met despite the loss of single largest generator.

Estimated Cost

£1.07bn

estimated total cost over the transition period.

Equates to an estimated

£552m

in Net Present Value terms.

On-island Generation

9%

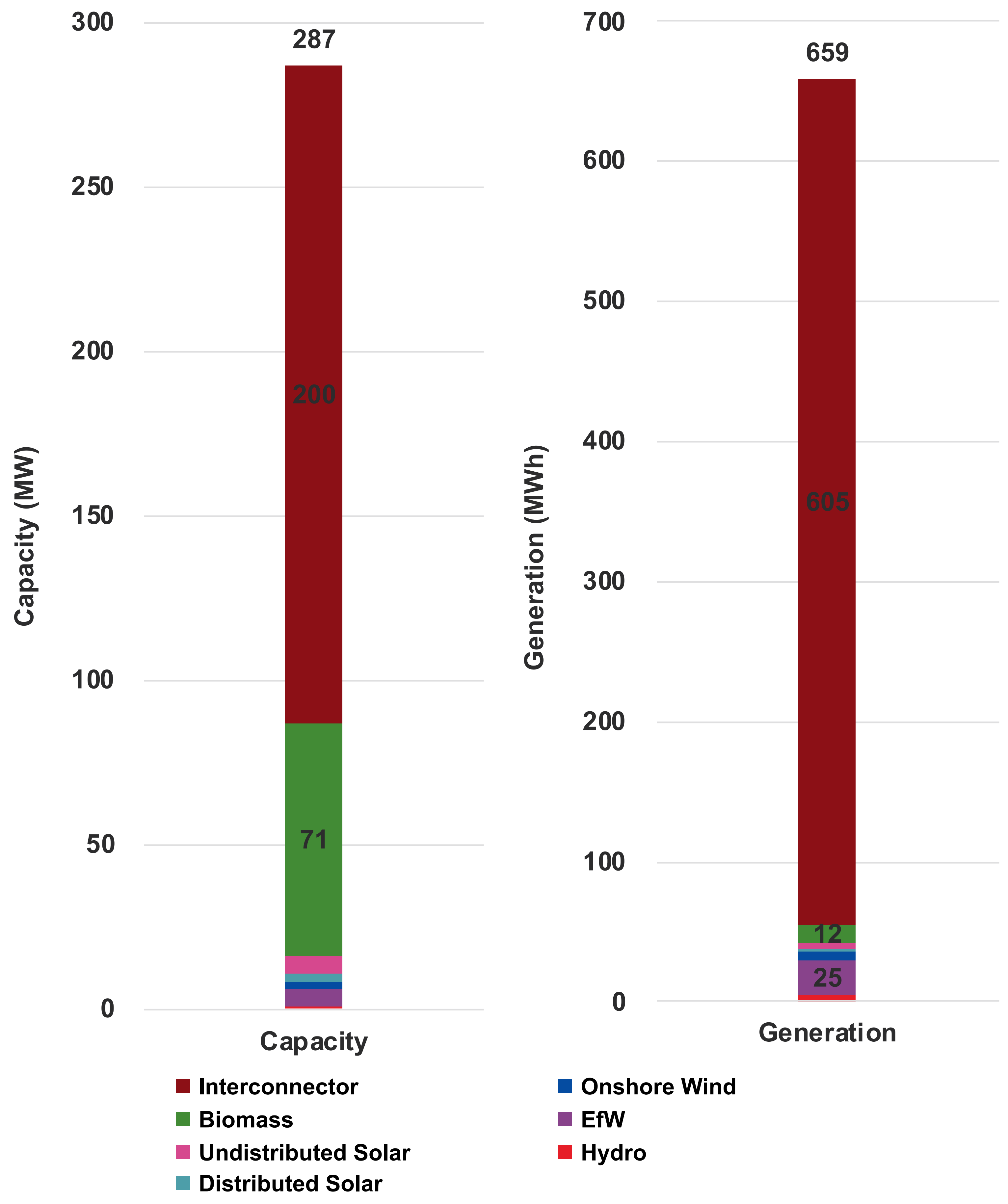
annual power demand met through on-island generation by 2050.

Decentralisation

2.3MW

total installed capacity of decentralised generation installed as behind-the-meter solar PV in new properties.

Projected Installed Capacity and Generation Mix by 2050



Scenario 4

Whilst scenario 4 has excess generation, imports are still required to meet about 40% of annual demand in 2050 due to intermittency of renewables.

Timeline

– 2028 – Diesels retire by the end of 2027, and 2 x 70 MW interconnectors are introduced to maintain N-2 resilience level. On-island renewables reach 60 MW.

– 2032 - CCGT retires by the end of 2031. An additional 70 MW interconnector is introduced by the start of 2032 to maintain N-2 resilience, leading to 3 new x 70 MW interconnectors, alongside 1 existing x 60 MW interconnector. On-island renewables continue to increase, reaching a total of 130 MW.

– 2040 – Existing 60 MW interconnector is refurbished / to maintain N-1 resilience. Total on-island renewable capacity reaches 310 MW. Battery storage reach 186 MW.

– 2050 – Total installed capacity reaches 934 MW, including 380 MW of on-island renewables. Significant increase in pumped storage capacity between 2049 and 2050, reaching 94 MW.

Resilience

N-2

island's power demand can be met despite the loss of two largest generators.

Estimated Cost

£1.8bn

estimated total cost over the transition period.

Equates to an estimated

£898m

in Net Present Value terms.

On-island Generation

58%

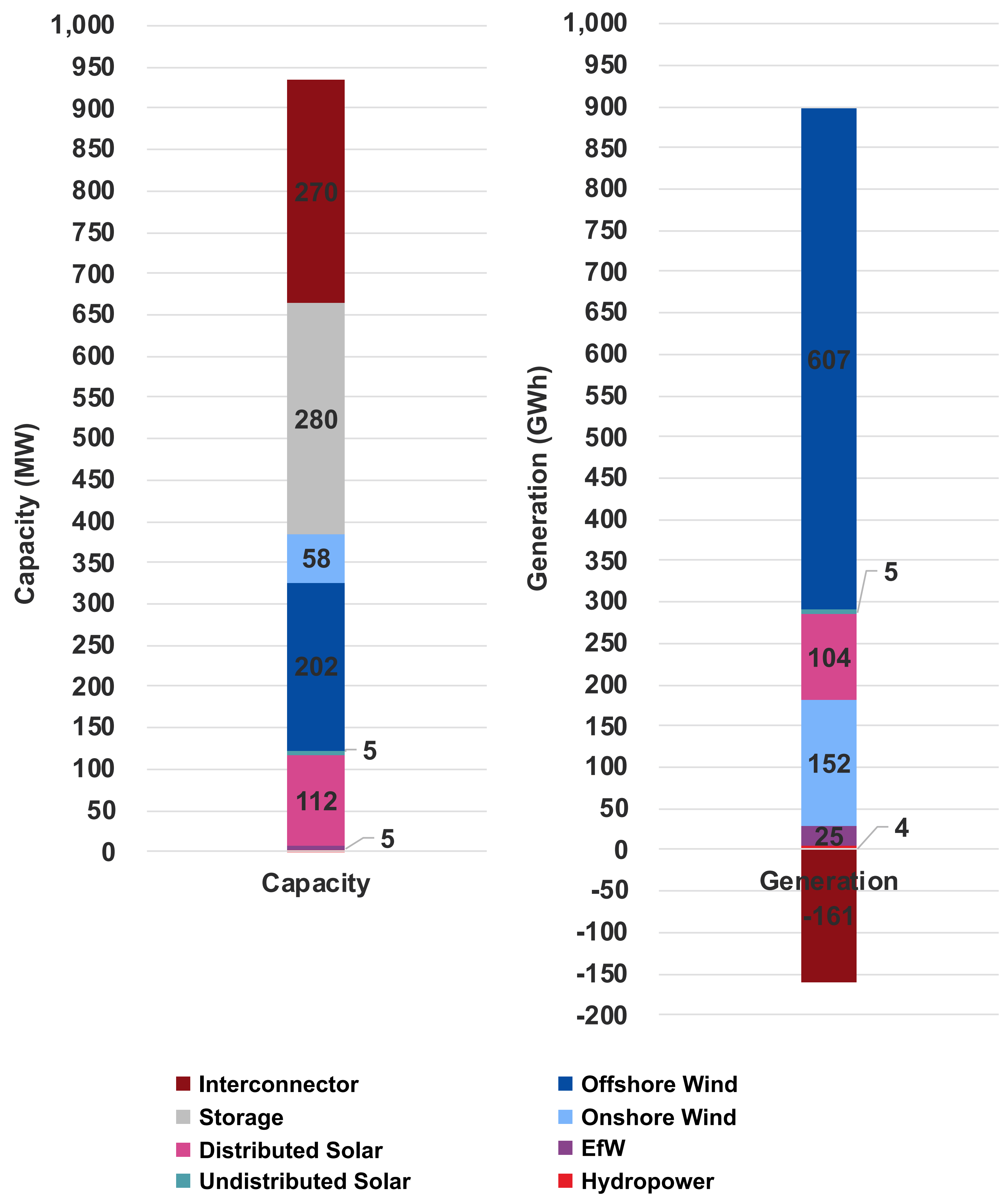
annual power demand met through on-island generation by 2050. Despite excess generation, imports are needed due to intermittency of renewables.

Decentralisation

112MW

total installed capacity of decentralised generation installed as behind-the-meter solar PV in both existing and new properties.

Projected Installed Capacity and Generation Mix by 2050



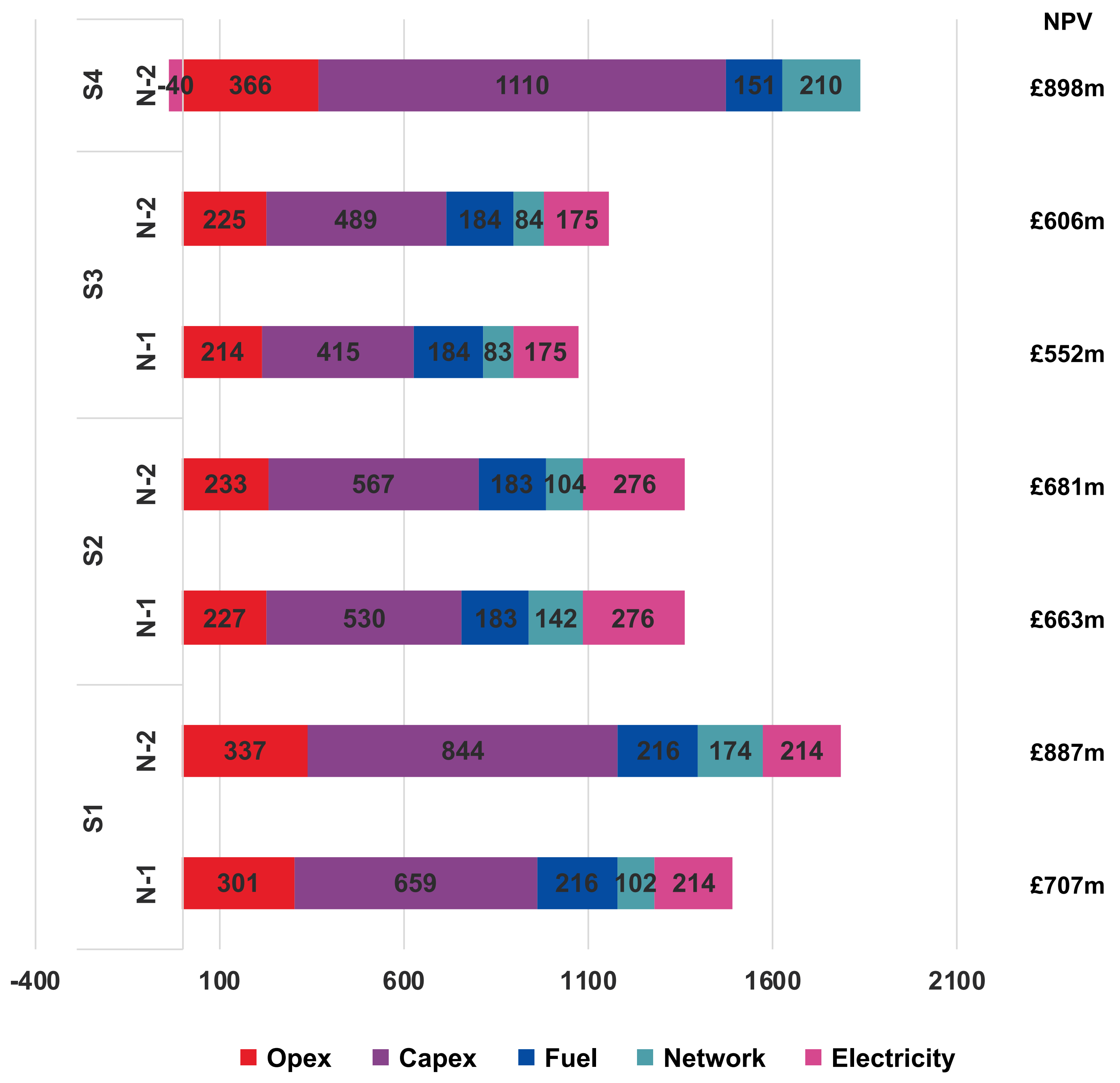
High-level cost implications (1 of 2)

Scenario 4 is estimated to be the most expensive, due to highest resilience and largest on-island generation.

Key points:

- The cost implications for a scenario are typically driven by the relationship between three key factors:
  - The level of resilience
  - The technology mix, including that required for resilience
  - The extent of on-island generation
- Scenario 4 has the maximum on-island generation. Consequently, it has the highest installed capacity across all scenarios, and is therefore estimated to be the most expensive.
- The higher the installed capacity, the more reinforcement is required on the network to accommodate the additional generating units.
- This further exacerbates the cost implications. As a consequence, the network implications cost are also estimated to be the highest for Scenario 4 compared to other scenarios.
- However, increasing on-island generation also minimises the need for importing energy from overseas markets (e.g., Great Britain). Consequently, the cost of importing energy is the lowest in Scenario 4.
- In summary, the benefits of increased on-island generation need to be weighed against the risk of importing power.
- Similarly, the benefits of increased resilience also need to be weighed against the potential risk and consequences of power outages.

Estimated total cost by scenario and resilience level (2020 - 2050)



High-level cost implications (2 of 2)

On a p/kWh basis, Scenario 4 is also estimated to be the most expensive.

Assumptions:

– Calculation methodology: The estimated cost in p/kWh has been calculated by dividing the sum of the annual costs by the sum of the annual demand over the transition period from 2020-2050.

– The estimated annual demand is based on the consumer transformation scenario.

– The estimated annual costs, annual demand and the resulting cost in p/kWh presented on this page have not been discounted.

Key points:

– The estimated costs in p/kWh presented on this page for various scenarios are not consumer tariffs, i.e. these are not retail prices. Hence, these estimates do not reflect of what consumers on the IoM will pay for the electricity in the future.

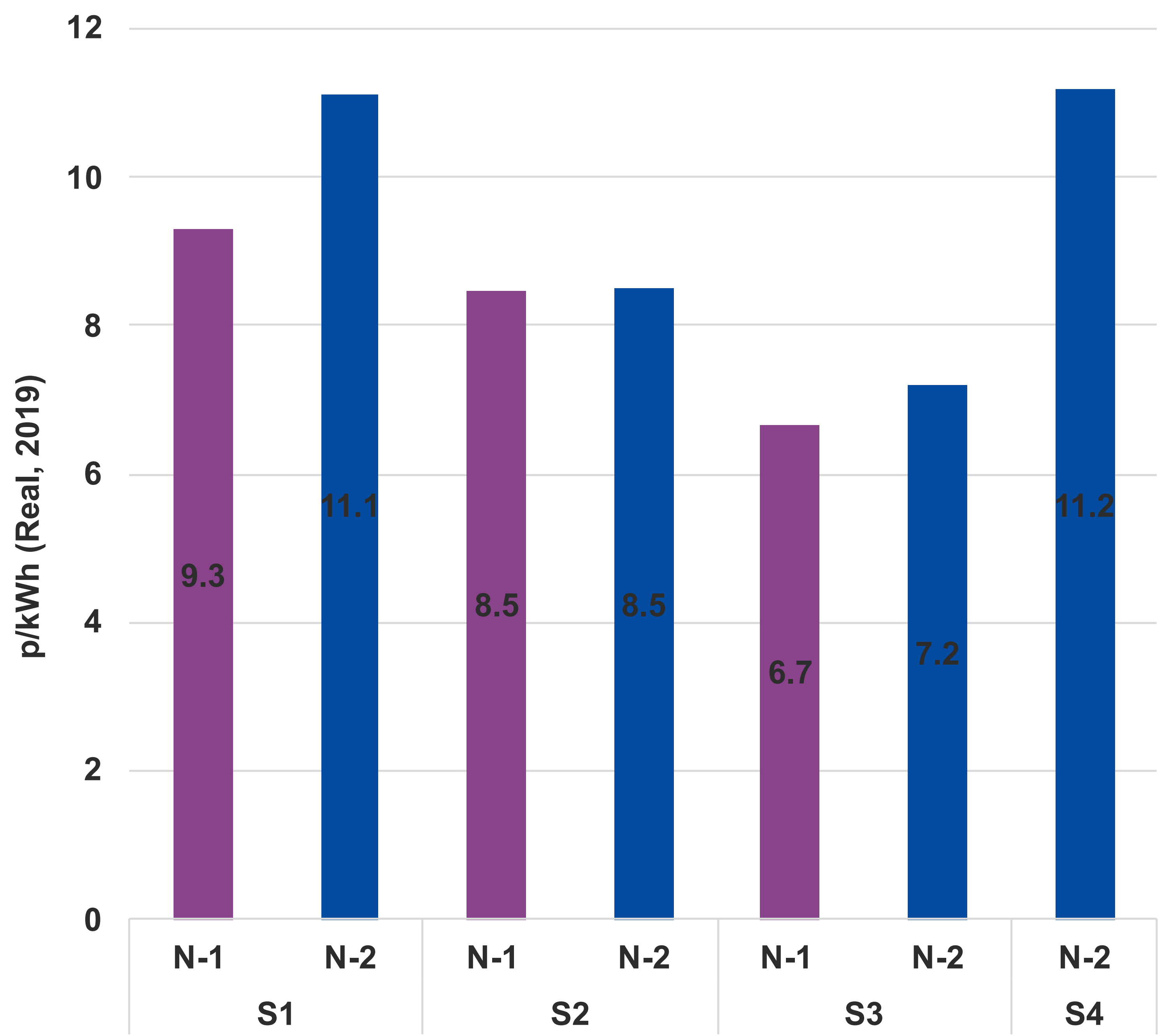
– It is likely that the retail price paid by end consumers will be higher. This is because the retail price is expected to include other items such as operational costs for MUA, potential taxes and levies and supplier margins.

– Additionally, the wholesale price estimates developed for these scenarios may also evolve over the long term with evolving supply and demand dynamics across the whole of north west Europe, and its interconnection with the GB market.

– Whilst this analysis gives a relative comparison of the costs of individual scenarios, the impact on end consumer price will depend on how the Isle of Man chooses to fund and finance the transition over the long term.

– The IoM have estimated the cost for MUA at 5.4p/kWh, however Arup have not reviewed this calculation or validated this figure.

Total estimated undiscounted scenario costs, p/kWh (Real, 2019)



Implications for end-consumer price

The impact on end-consumer prices will depend on how the island chooses to fund and finance the transition.

Key points:

- The retail electricity price, paid by the end consumer, is comprised of a variety of items. Typically, these include wholesale price, network cost, operating cost, environmental levies and taxes, and suppliers' profit margins.
- The wholesale cost is often the largest single component of an end consumer's bill. Historically, the wholesale cost has been correlated to the global commodity prices for fossil fuels such as coal, gas and oil.
- Whilst the Isle of Man does not have a wholesale market, it is likely to be exposed to volatility and variability in global gas prices, since about 90% of the island's power is generated from the gas-fired power plant and gas is sourced from Great Britain, where prices will be strongly correlated to the GB gas hub; the National Balancing Point (NBP).
- In the net zero scenarios, the influence of commodity prices on wholesale and by extension, retail prices is expected to weaken. Instead, the retail price in the long term will be mainly driven by the cost of building and operating new renewable power plants, network upgrades and operations, the cost of importing power from overseas (if any) and other operating costs.
- The trajectory of future retail prices will therefore depend on how the IoM choses to fund and finance the transition over the longer term.
- For instance, IoM could choose to fund the transition through general taxation, in which case the impact on end consumers' bill is likely to be low.
- Alternatively, it could chose to fund the transition by introducing environmental levies (similar to that in Great Britain) which are added to electricity bills. In this case, consumers may see some increase in their bills.
- However, this increase would be counteracted to some extent by reducing reliance on fossil fuels and hence reduced exposure to global commodity prices – essentially, the fuel for renewables such as wind and solar is free and hence it is cheaper to generate a unit of electricity from intermittent renewables than it is from fossil fuel based power stations.

Scenario 5

Whilst there are economic and societal benefits in pursuing Scenario 5, key commercial challenges also need addressing.

Key features:

– Scenario 5 is premised on the construction of a 700-800 MW offshore windfarm in the Isle of Man territorial water.

– The power generated from this offshore wind farm, alongside other renewable technologies, will be used to meet domestic demand.

– Excess power could be exported to the British or Irish markets, it could be converted to hydrogen or stored in large batteries on the island.

Key assumptions:

51%

load factor for IoM, rising to 52% for Ireland and 55% for GB.

10%

uplift in infrastructure costs (included in capex) for IoM.

6.3%

hurdle rate for IoM and GB, decreasing to 5% for Ireland.

Key considerations:

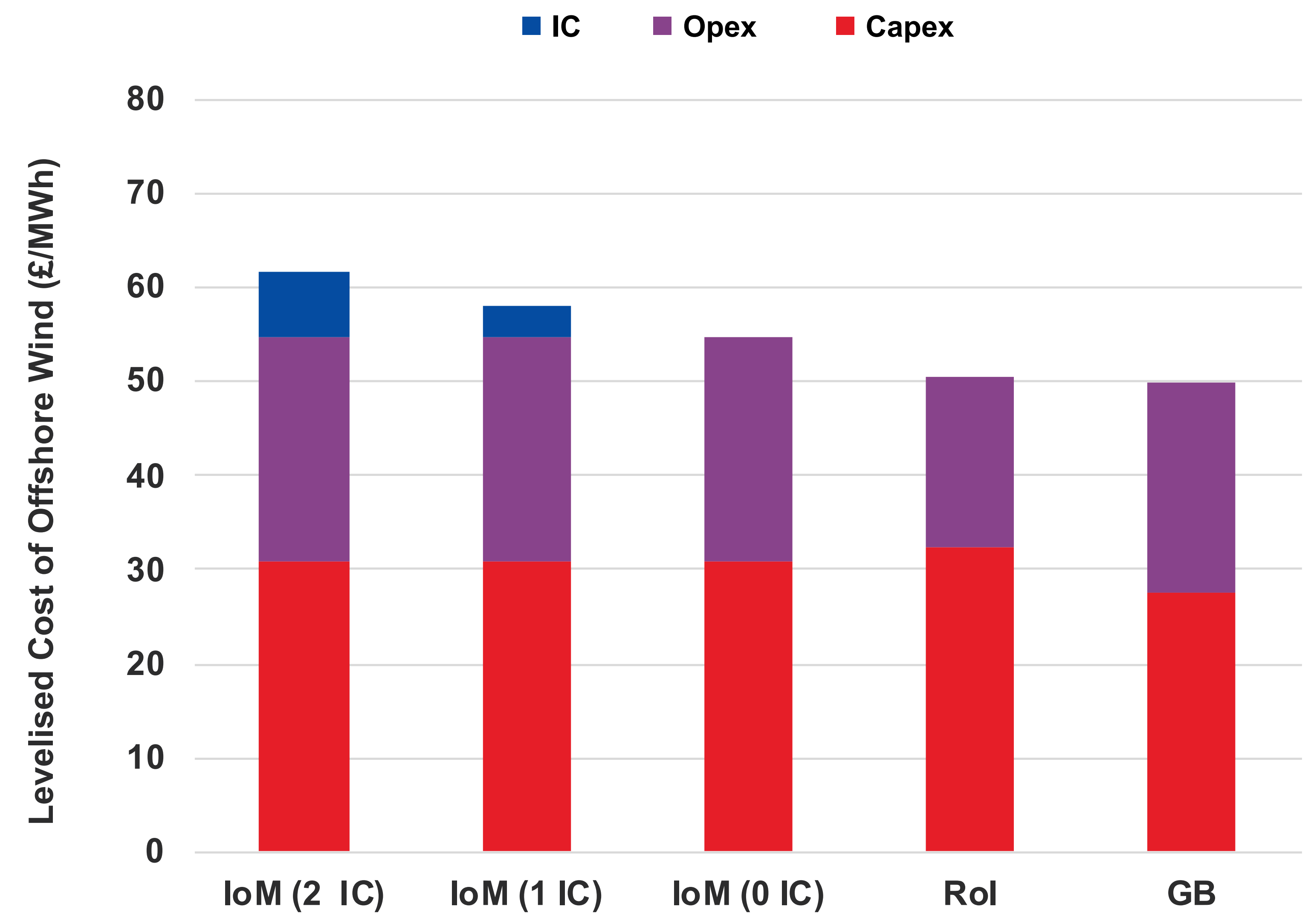
– In this scenario, the island will see economic and wider societal benefits from the lease of sea bed, and the operation and maintenance base.

– However, initial analysis suggests that the cost of producing power from offshore wind in IoM is higher than it is in the GB or Ireland.

– Windfarms built outside the UK cannot currently access the UK government subsidies. This poses a commercial challenge for exporting excess power generated from overseas market to the UK.

– Power Purchase Agreement (PPA) provide a route to selling excess power to overseas markets; however, this requires further assessment.

– Therefore, the commercial arrangements for this scenario, particularly those related to the sale of excess power, need further assessment.



CAPEX	£1.46bn	£1.46bn	£1.46bn	£1.74bn	£1.42bn
OPEX	£2.50bn	£2.50bn	£2.50bn	£2.17bn	£2.53bn
IC COST	£0.38bn	£0.19bn	-	-	-

Note:
IoM (2 IC) – this scenario includes the cost of two additional interconnectors, once each with GB and Ireland, for exporting power from IoM.
IoM (1 IC) – this scenario includes the cost of one additional interconnector with GB only (none with Ireland) for exporting power from IoM.
IoM (0 IC) – this scenario does not include the cost of any additional interconnectors. It is assumed that power is exported using the interconnectors that are constructed to provide resilience.

A high level roadmap for transition

Action required across six key areas to enable the energy transition.

Currently, non-renewable gas fired power stations or combined cycle gas turbine (CCGT) produce around 93% of the island's electricity.

In order to successfully plan and implement a route to net zero emissions by 2050, the IoM must focus on six key areas to form an agreed and clear plan of the short term (0-5 years), medium term (5-10 years) and longer term (>10 years).

Over this time, new renewable technologies such as onshore/offshore wind, biomass and solar energy can be developed on the island, alongside current methods of hydropower, energy from waste and interconnectors with the UK.

	Short term	Medium term	Long term
Electricity Demand	Continue smart meter roll-out Implement policy changes related to building and appliance efficiency standards.	Electric heating and heat pumps become prevalent. Increasing number of EVs start operating on the island	Smart EV charging and smart appliances become the norm. Majority of the privately owned small vehicles on the island are electric.
Electricity Generation	Undertake evidence based assessments to determine the required level of resilience in the future system Undertake detailed assessment for new interconnector with GB.	Start interconnector planning, design, construction and commissioning. Begin to phase out fossil fuels	Track emerging technologies, mainly carbon capture use and storage (CCUS) and hydrogen to assess suitability and demand.
Policies and laws	Finalise transport, heating and waste management strategies. Introduce carbon budgets and carbon tax to support air quality improvements Introduce incentives for uptake of EV Introduce incentives for increased uptake of behind-the-meter renewable generation	Roll out of public EV charging stations. Carbon tax comes into force.	Ban on sale of new petrol and diesel vehicles comes into force First few hydrogen refuelling stations built to service public transport and HGVs.
Funding and Financing	Evaluate options for ownership, operation, financing and funding of new generation assets.	Develop business cases to secure funding as necessary Ring fence medium and long term funding and financing sources.	Review financial key performance metrics and adjust operations, funding and financing for improved performance
Land Use	Identify suitable land areas and to accommodate new generation and network related assets. Identify land areas for biomaterial production and processing. Update long term development plans reflecting the energy transition.	Begin procurement, planning and enabling works to accommodate new generation and network related assets. Start biomaterial production and storage	Begin afforestation and land restoration, where feasible, to assist with 'negative' emissions (i.e. emissions absorption from atmosphere).
Network Infrastructure	Investigate potential for smart/flexibility solutions and improve decision making tools. Develop a digital network infrastructure for increased monitoring and improved decision-making.	Coordinate increasing load related and asset age/ condition related investment.	Review effectiveness of various reinforcement measures and smart/flexibility solutions from a planning, investment and operational perspective.

Basis of Preparation

- In preparing this report we have relied on information provided by others and we do not accept responsibility for the content, including the accuracy and completeness, of such information. In no circumstances do we accept liability in relation to information provided by others.
- We emphasise that any forward looking projections, forecasts, or estimates are based upon interpretations or assessments of available information at the time of writing.
- The realisation of the prospective financial information is dependent upon the continued validity of the assumptions on which it is based. Actual events frequently do not occur as expected, and the differences may be material. For this reason, we accept no responsibility for the realisation of any projection, forecast, opinion or estimate.
- Findings are time sensitive, relevant only to current conditions at the time of writing. We will not be under any obligation to update the report to address changes in facts or circumstances that occur after the date of our report that might materially affect the contents of the report or any of the conclusions set forth therein.
- No person other than our Client and any party to whom reliance has been expressly permitted by us pursuant to a reliance letter may copy (in whole or in part), use or rely on the contents of this report without our prior written permission. Any copying or use of this report (in whole or in part) whatsoever shall be accompanied by or incorporate this notice at all times.
- We accept no responsibility for, and have not authorised, the contents of any report, prospectus, supplementary prospectus, listing particulars, supplementary listing particulars, presentation or other document or communication in respect of the sale, acquisition, offering or transfer of any shares or securities or interest in them, whether on the primary or secondary market or otherwise, which uses, includes or incorporates any report, deliverable or information, or any element thereof, prepared by us under or in connection with our Appointment.
- The scenarios presented in this report are specific to the Isle of Man, and have been developed based on the constraints and requirements identified by our Client, and assumptions agreed upon with our Client. The scenarios are likely to change, if the underlying constraints, requirements and assumptions change. These scenarios are not replicable for other locations, including other island jurisdictions.

This report is based on information gathered from the following sources

- Review of publicly available information (such the National Grid Future Energy Scenarios (2020) and the BEIS Cost of Generation Report (2020))
- Information provided in the virtual data room (VDR) by the Client and other stakeholders
- Virtual meetings and workshops held with the client and wider stakeholders, including Manx Utilities Authority (MUA)
- Information shared by the Client during virtual meetings, workshops and via emails
- Responses to the Request for Information (RFI)

Glossary

BEIS	Department for Business, Energy and Industrial Strategy
CCGT	Combined cycle gas turbine
CCUS	Carbon capture use and storage
CO2	Carbon dioxide
CT	Consumer Transformation
EV	Electric vehicle
GB	Great Britain
GHG	Greenhouse gas
GWh	Gigawatt hours
HGV	Heavy goods vehicle
IC	Interconnector
IoM	Isle of Man
LtW	Leading the Way
MUA	Manx Utilities Authority
MW	Megawatt
NPV	Net present value
RFI	Request for information
RoI	Republic of Ireland
ST	System Transformation
UK	United Kingdom
VDR	Virtual data room