Workshop on embedded benefits modelling

Assessing impact of changes to network charging arrangements

21 March 2017

Contents

Reducing distortions from TDR charges will increase social welfare…

Distorted decisions in the short term…

Smaller EG generate out of merit to ensure they hit the triad periods, artificially dampening the wholesale price

… pushing more efficient plant out of merit, leading to higher fuel cost (and possibly variable plant opex)

… potentially changing peak consumption decisions

Distorted decisions in the longer term…

Smaller EG have a competitive advantage over larger EG and TG in the capacity market, artificially dampening the capacity price

… leading to build of net more expensive units

… and possibly over-investment in security of supply

Smaller EG build may lead to more distribution connections and so a requirement for more distribution network investment (or delayed distribution connections)

… and will also result in a change to costs to customers

Removal of payments from aggregate of customers to smaller EG

Change in total CM payments met by customers

Change in wholesale payments (at peak, and overall as a result of a change in investment) met by customers

Also consider impact of CfD payments met by customers

Increased loss of load expectation (but still consistent with CM demand curve)

We use modelling to consider the potential impact of proposed changes on a range of outcomes

Wholesale market dynamics

- Wholesale prices, CM clearing prices including plant mix that results from the CM, reserve costs, BSUoS charges, and CO_2 emissions.
- System security as estimated by Loss of Load Expectation (LOLE).

Impact on generating technologies

- Load factors of generating technologies.
- Economics of diesel and gas reciprocating engines, including the number of hours run to chase triads.

System costs

- These costs represent the actual resource cost of running the system.

Consumer costs

- Separate to system costs, consumer costs measure how consumers are affected by the proposed changes. While system cost represents the true resource cost of running a system, this is independent of who pays and receives money.

In the scope of our modelling work, we have not quantitatively considered a number of factors

Input sensitivities

- Modelling outputs are sensitive to a number of assumptions on future uncertain variables and behaviours. Changes to these can result in significant changes to outputs.
- These inputs include (among others): fuel prices, capital costs associated with new build, and electricity demand.

Non-delivery of contracted capacity

- We have assumed that all capacity granted CM contracts in the previous CM auctions will not renege on these contracts and will deliver as expected.

Network costs

- We have not provided estimates for the effect on network costs as part of the system cost analysis. Since removing distortions should reduce inefficient network build, if anything we understate the positive impact on system costs.

In any case, it is critical to note that modelling should not be the only basis of a regulatory decision

Modelling has natural limitations

- Modelling is attempting to predict the future outcome of a new regime
- It relies on estimates of key variables in the future
  - Fuel prices
  - Carbon prices
  - Generation costs
  - Demand
  - …
- The one thing we know: we don't know
- Different results are possible if you assume different inputs

It should be used carefully

- It provides an internally consistent framework to understand the types of impacts which a new regime might have
- It can also give an indication of the direction, and possibly the broad scale of individual impacts
- It may also allow a judgement to be made on the size of different effects, if they go in different directions

The final regulatory decision should be based on principles, not on whether or not a particular outcome is thought likely to be achieved

Model overview

- The model used to conduct this analysis was LCP EnVision, an integrated model of the GB electricity market.
- EnVision uses the same underlying modelling platform as BEIS' Dynamic Dispatch Model (DDM).
- LCP developed the DDM for DECC in 2011 and have since provided ongoing development and support to DECC/BEIS in the modelling of the GB electricity market.
- The DDM is used for BEIS' annual UEP projections and in impact assessments of policy changes.
- The security of supply modelling implemented in the DDM is used by National Grid to set the capacity target in the annual GB Capacity Market auctions.

Model overview

EnVision models numerous aspects of the GB electricity market, including:

- **Wholesale dispatch**
  - Utilises LCP's dispatch algorithm
  - Captures plant's operational characteristics such as start costs and minimum up/down times.
  - Sample days at half-hourly granularity, under different levels of intermittent generation.
  - Algorithm is also implemented in the DDM, used by BEIS, and in the Supplier Obligation Forecasting Model, used by the Low Carbon Contracts Company in their modelling of CFD payments.
- **Triad chasing at peak**
  - Model identifies the hours that triad-chasing plant should run to ensure they capture the triad benefit.
  - Dynamically calculated based on the installed capacity of embedded generation and demand levels over peak periods.
  - In these hours, the SRMCs of triad-chasing plant are adjusted to account for the triad benefit.

Model overview

EnVision models numerous aspects of the GB electricity market, including:

- **Capacity Market**
  - CM auctions are simulated within the model.
  - Plant bids are calculated based on the 'missing money' required
  - Plant simulate the future and create expectations of their future profitability.
  - Bids include expected wholesale and ancillary revenues, as well as all capital and operating costs.
  - This is the same core engine as the DDM, which is used by National Grid in setting the capacity target each year.
- **Reserve and balancing markets:**
  - Modelling reflects actions in procuring reserve services.
  - Includes headroom, footroom and system inertia.
  - The balancing market is also simulated to capture actions required due to volatility in demand and intermittent generation.

Scenarios examined – value of demand TNUoS residual

Scenario	Assumption regarding the size of the payment to smaller EGs
Status Quo	The demand TNUoS residual increases in line with National Grid's forecast until 2021, after which it remains flat in real terms at £72.03/kW (£66.0/kW in £2016 terms).
Scenario 1	From 2019, the charge is set at £45.33/kW plus RPI. This is equal to the current demand TNUoS residual level.
Scenario 2	From 2019, the charge is set at £20.12/kW plus RPI. This is equal to the value of avoided GSP (calculated by National Grid) investment and future transmission reinforcement costs (calculated by Cornwall Energy).
Scenario 3	From 2019, the charge is set at £1.62/kW plus RPI. This is equal to the value of avoided GSP investment.
Generator residual scenario	From 2019, the charge is set to the level of the generator residual tariff (adjusted for CPI).

Scenarios examined – grandfathering and phasing

Across these scenarios, we have then considered a number of options for any possible modification, as discussed with Ofgem:

- **Grandfathering**

  No Grandfathering; or

  A. £45.33/kW plus RPI for existing capacity commissioned before 1st July 2017;

  B. £45.33/kW plus RPI for reciprocating engines with Capacity Market contracts for delivery in 2018/2019 and 2019/2020; or

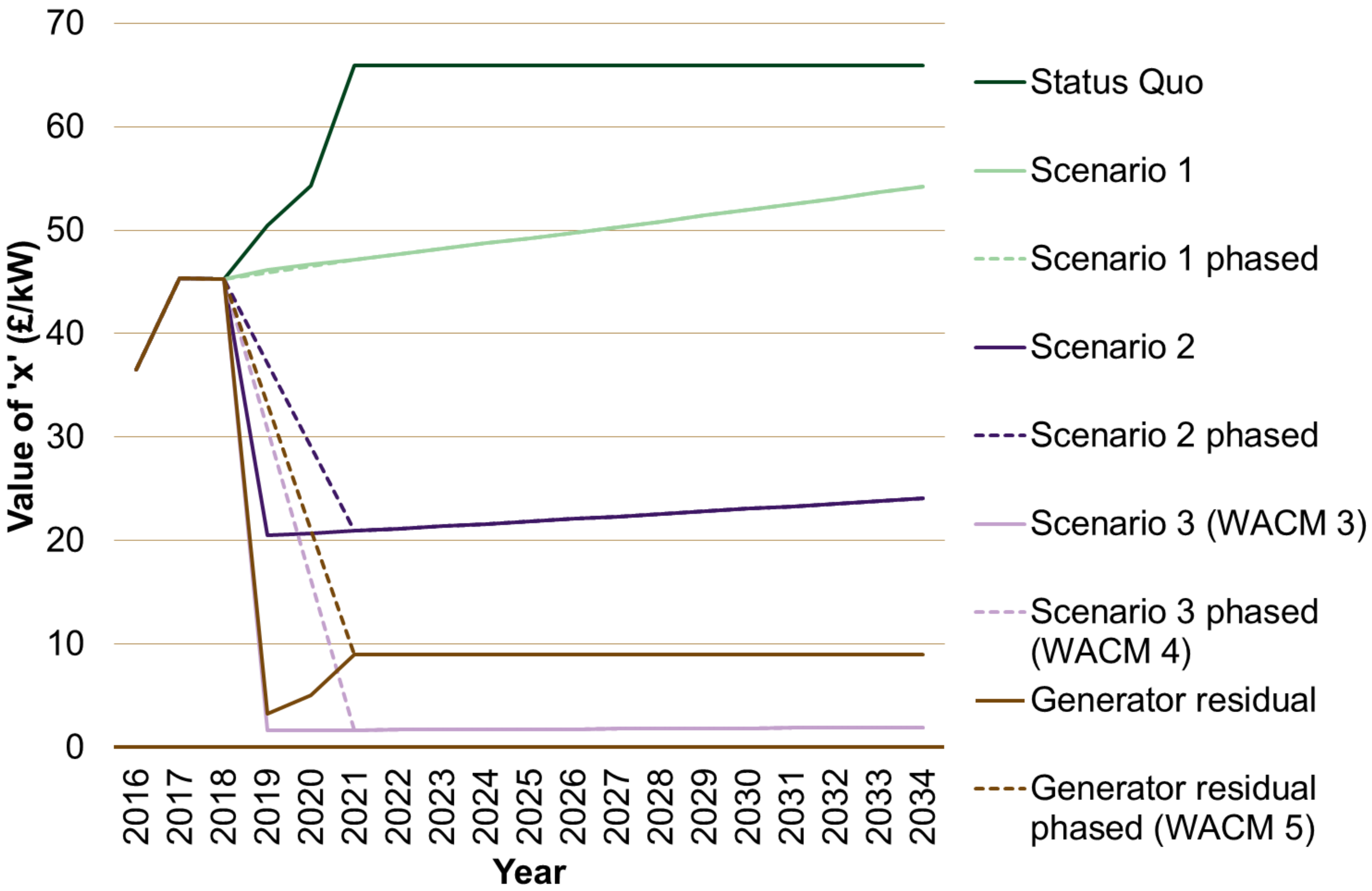
  C. Both of the above.

- **Phasing**

  Immediate implementation from 2018/19; or

  A. 3–year phasing.

Scenarios examined



Broader modelling inputs

- Modelling inputs were agreed with Ofgem and sourced from publicly available sources where possible:

Assumption	Source
Demand	National Grid FES 2016 'Slow Progression'
Wind, Solar, Nuclear build	National Grid FES 2016 'Slow Progression'
Interconnection build	National Grid FES 2016 'No Progression'
Coal retirements	National Grid FES 2016 'Slow Progression'
Fuel prices (coal, gas, carbon, oil)	National Grid 2016 FES basecase
Capex for CM build (CCGT, OCGT, reciprocating engines)	BEIS Nov 2016 Cost report – Low

Model outputs

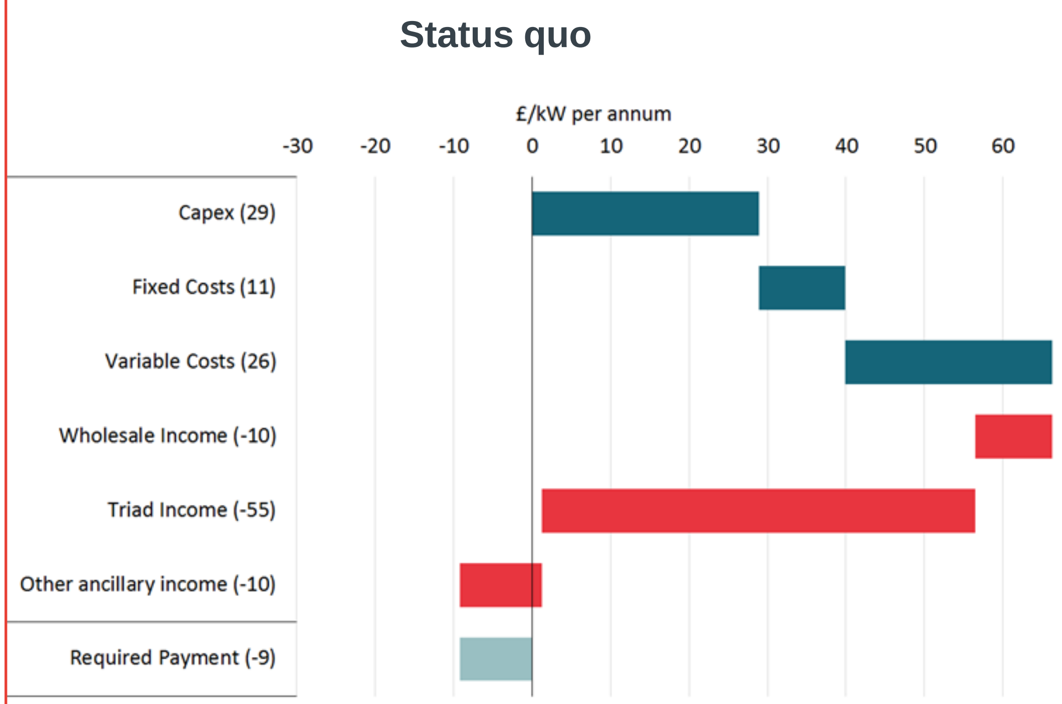
EnVision provides numerous metrics in its modelling of the GB electricity market. These include:

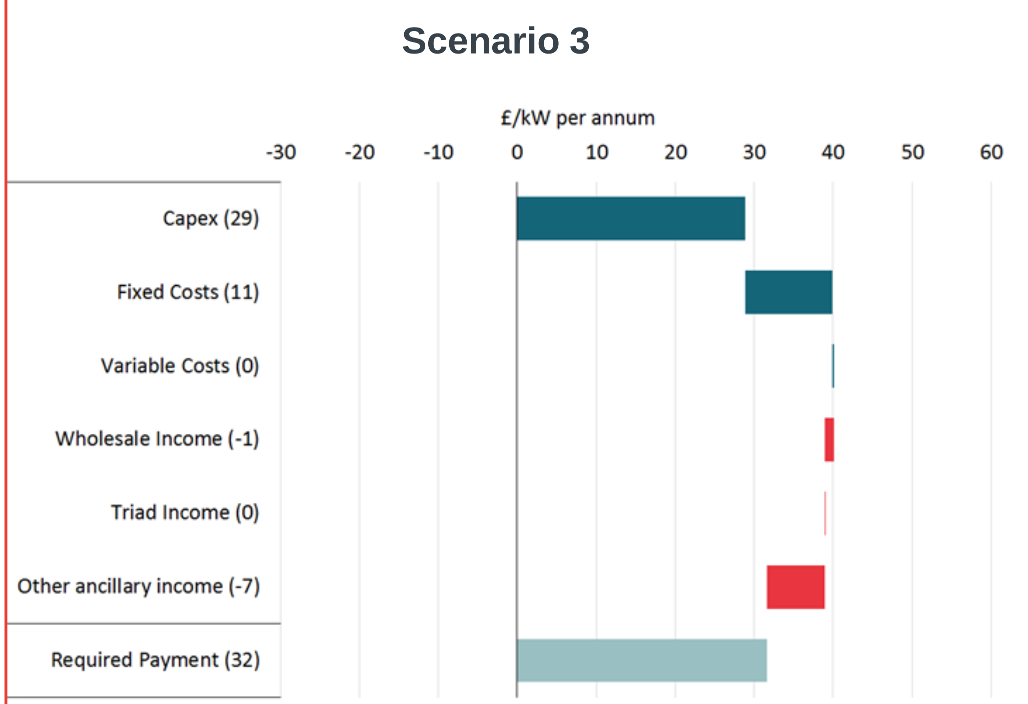
- **Capacity mechanism outcomes –** CM auctions are simulated each year to report new build, retirements and clearing prices.
- **Wholesale market outcomes** – half-hourly dispatch for each power plant on the system, and resulting wholesale prices.
- **System costs –** These are the resource costs of running the system. These include capital costs, fuel costs, operating costs, carbon costs and value of energy unserved.
- **Consumer costs –** These are the costs the consumer faces, which may include transfers which do not impact system costs. These include wholesale costs, policy costs (eg CM payments and CFD support payments), demand TNUoS costs and embedded benefit payments.
- **Security of supply –** Using the same probabilistic calculation that is used to set the capacity target, the realised loss of load expectation (LOLE) is calculated every year.

Capacity market bids

- Reducing the level of embedded benefits increases the CM bids of new build reciprocating engines.
- The charts below show the calculation of the CM bid of a new build reciprocating diesel engine with and without the TDR embedded benefit.

Revenue breakdown for an archetypal new reciprocating diesel engine, 2022

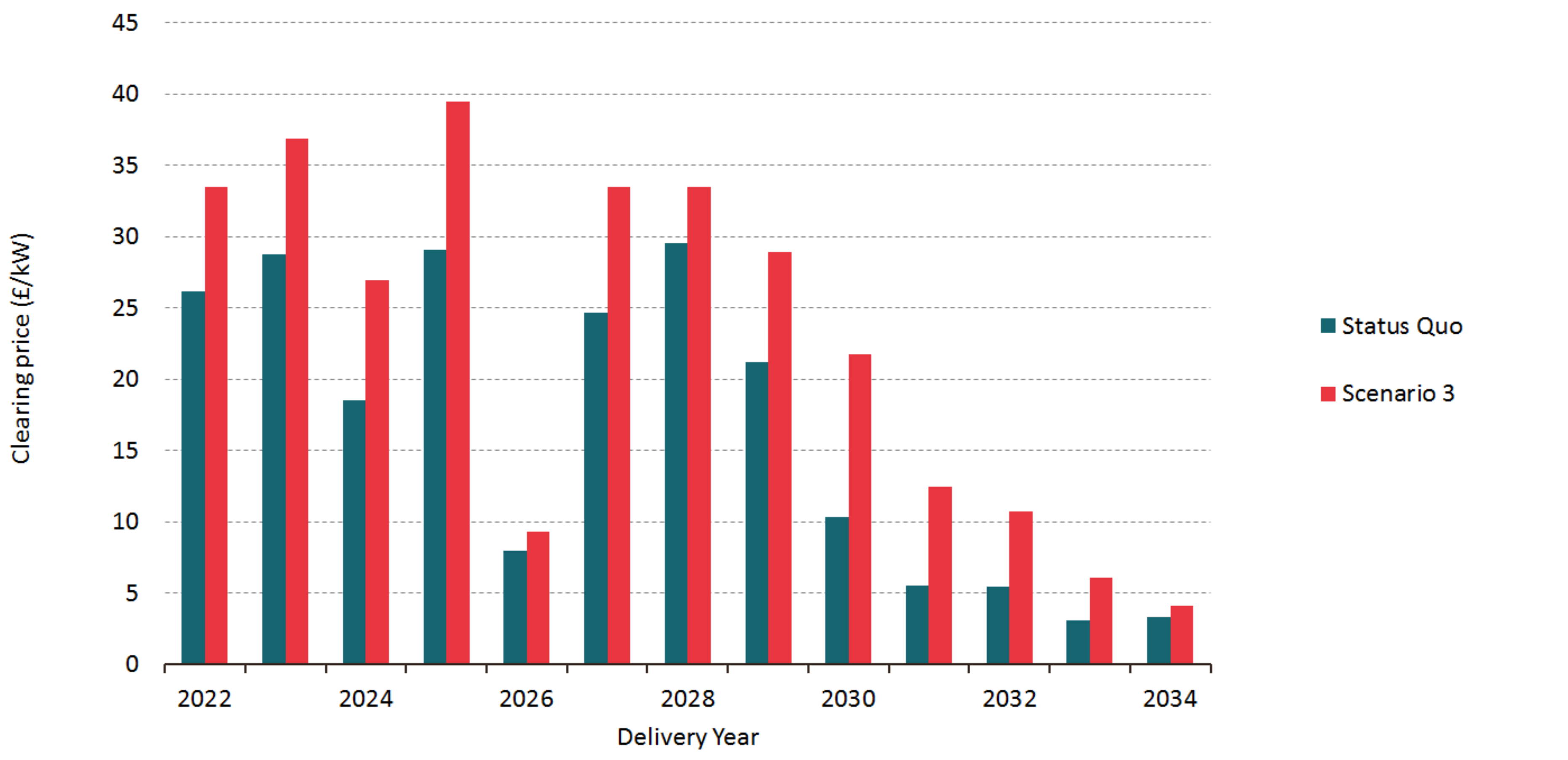




Capacity market clearing prices

- The increases in CM bids of new build reciprocating engines leads to higher CM clearing prices under Scenario 3 compared to Status Quo.

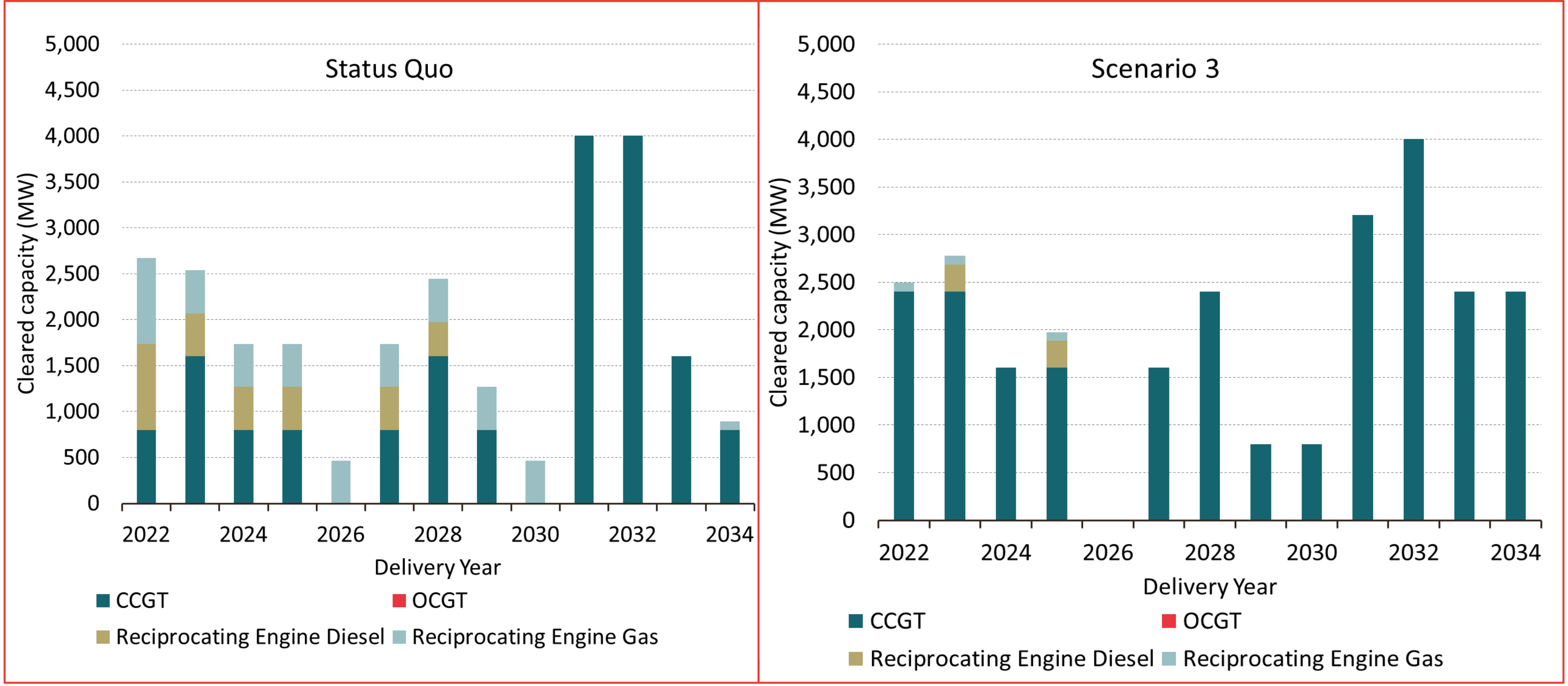
CM Clearing prices, 2022-2034



New build capacity through the Capacity Market

- Higher clearing prices under Scenario 3 procure an increased number of new build CCGT than under Status Quo. These units replace the reciprocating diesel and gas engines that clear under Status Quo.

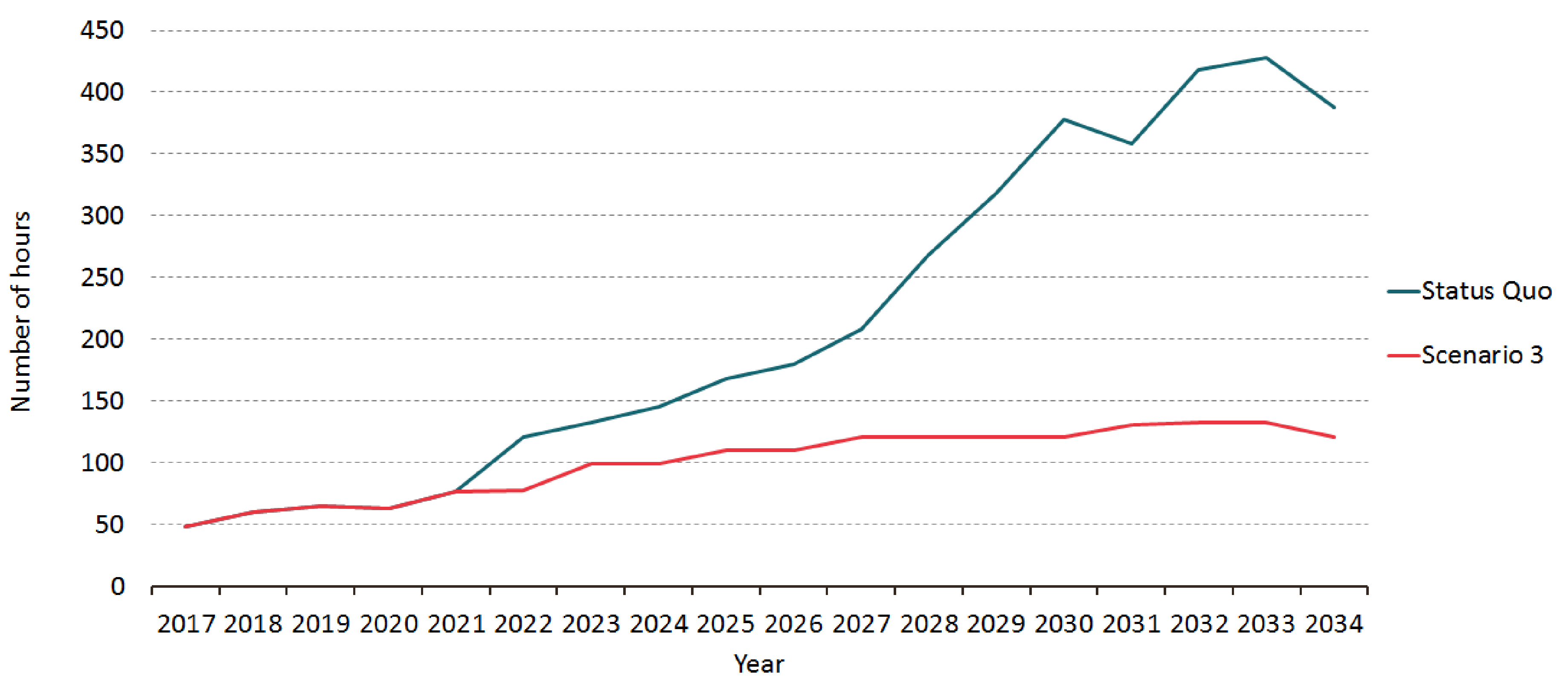
Cleared capacity in the CM, 2022-2034



Triad chasing hours

- In order to receive the triad benefit, smaller EGs must ensure that they dispatch during triad periods.
- Since triad is calculated based on demand net of smaller EG generation, they are forced to run over more periods as embedded capacity increases to be certain of covering triad.

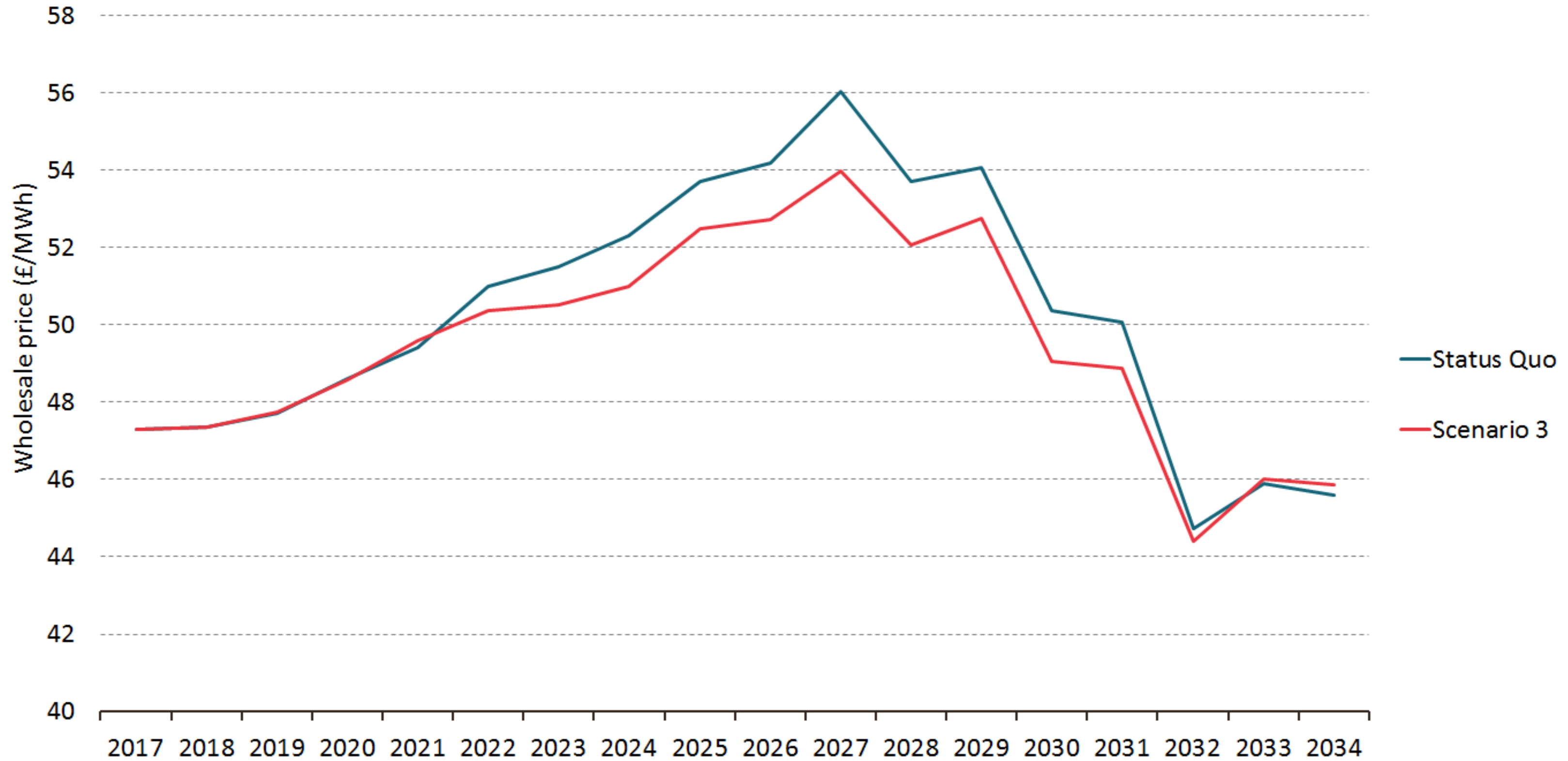
Triad chasing hours, 2017-2034



Wholesale prices

- Differing outcomes in the CM produce different fleets between the Status Quo and Scenario 3 from 2022 onwards.
- The reduction in plant targeting triad hours increases peak prices. However, increased procurement of new build CCGT in Scenario 3 supresses average annual wholesale prices by displacing older, less efficient plant in wholesale dispatch.

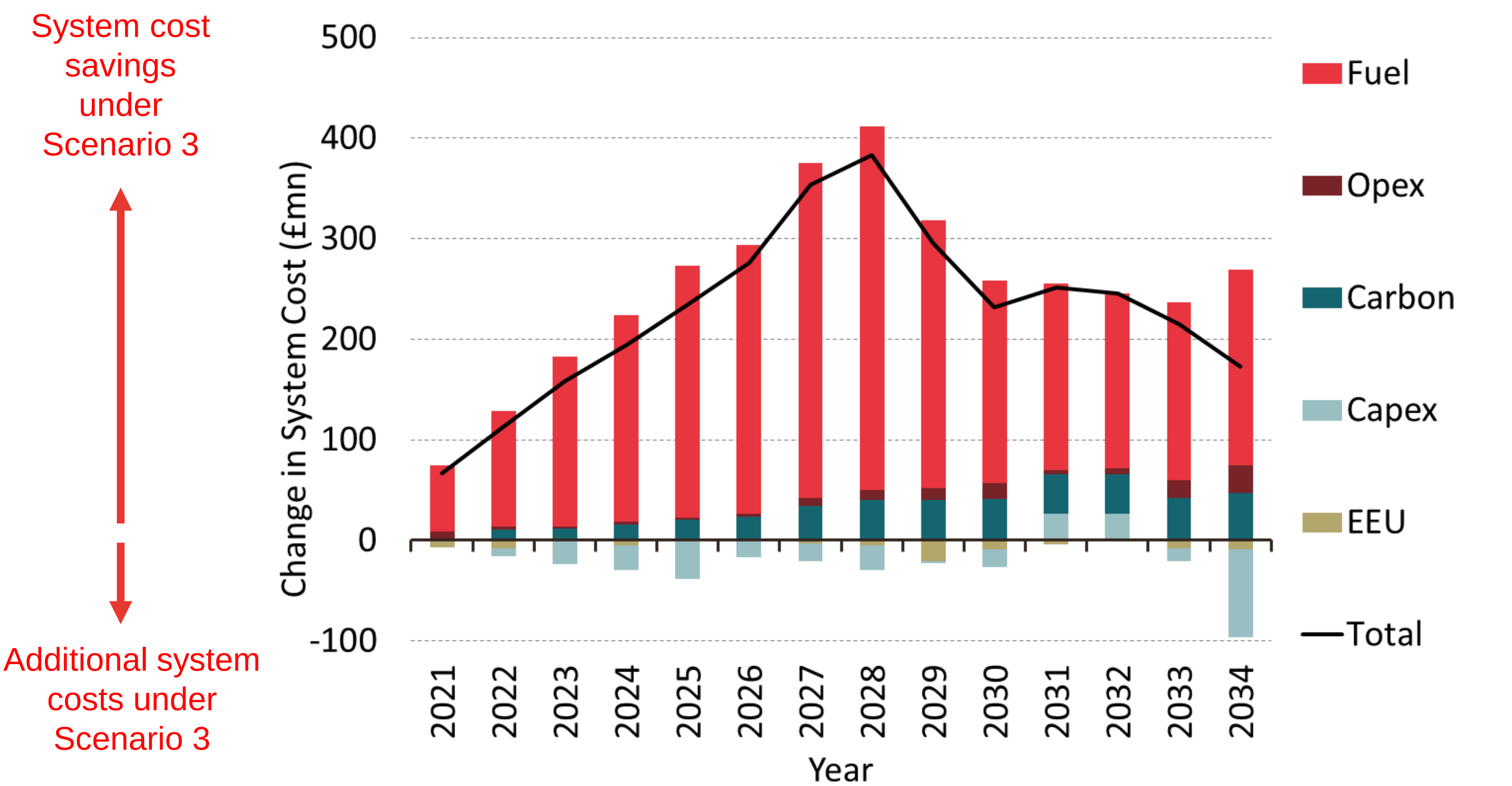
Wholesale prices, 2017-2034



System cost impact

- We observe system cost savings under Scenario 3 compared to Status Quo.

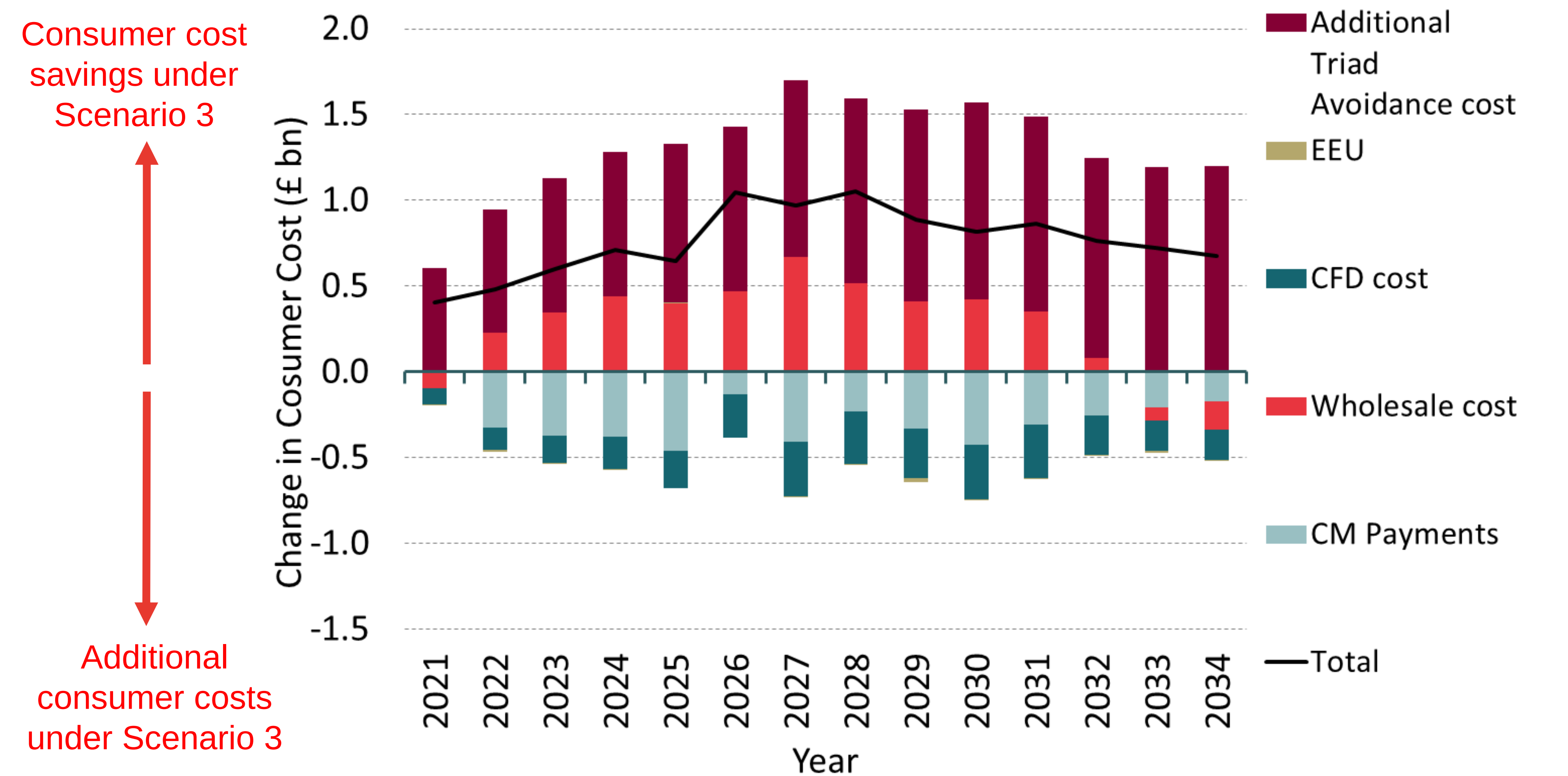
System cost savings, 2021-2034



Consumer cost impact

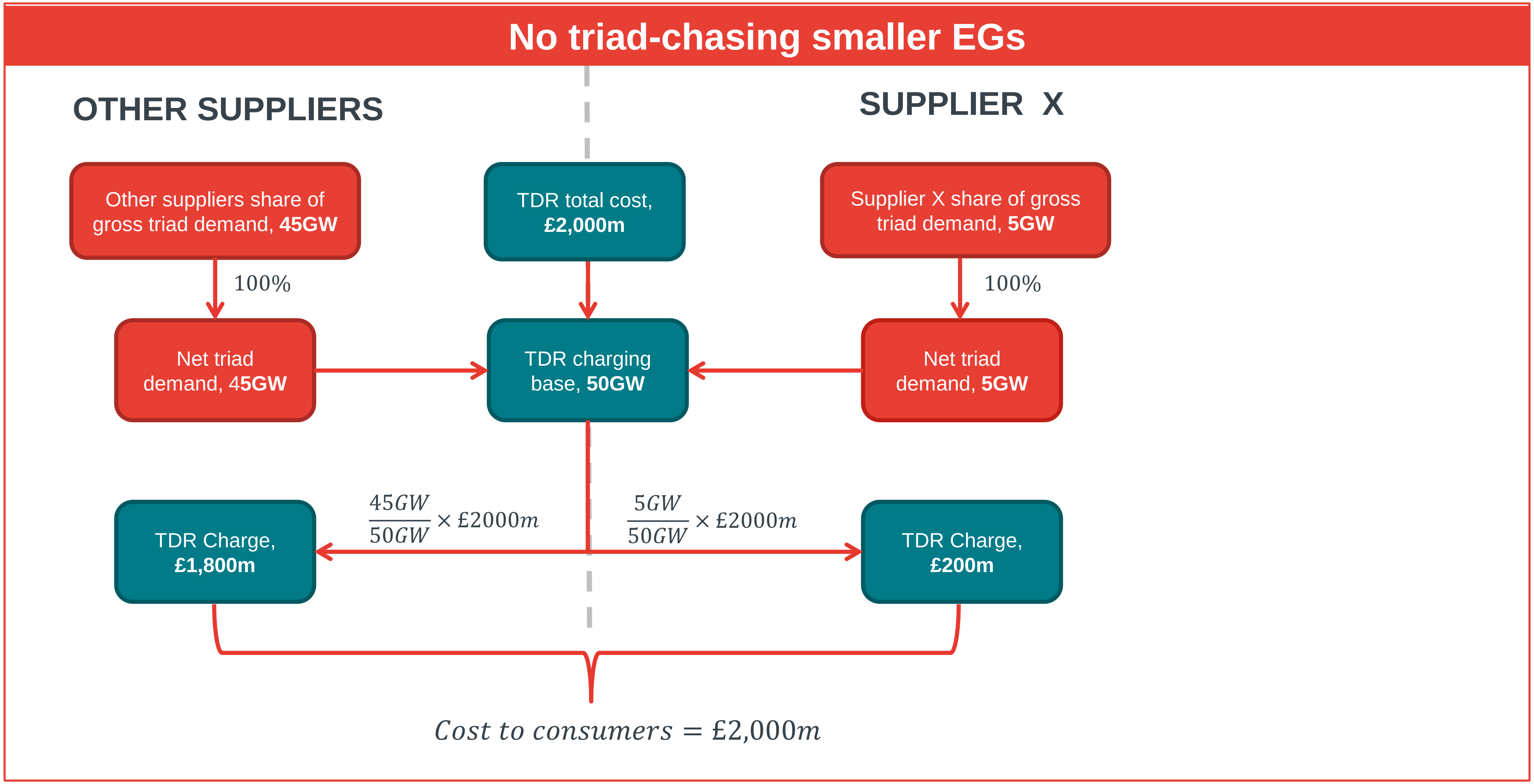
- We observe consumer cost savings under Scenario 3 compared to Status Quo. The impact is much larger than on system costs, primarily due to the “Additional triad avoidance cost”.

Consumer cost savings, 2021-2034



Consumer cost impact
Triad avoidance payment – Illustrative example

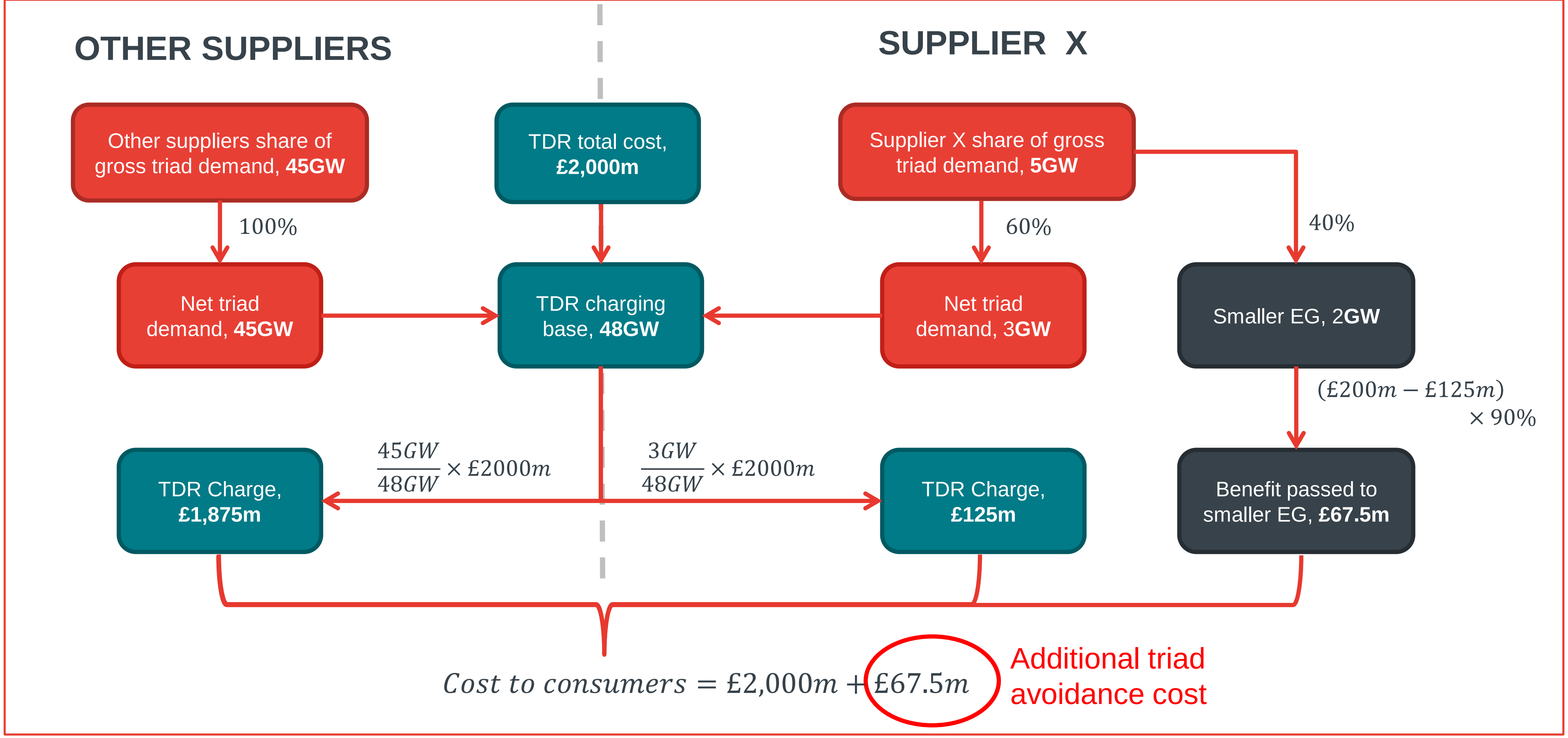
- The largest element of the consumer cost saving is the "Additional triad avoidance cost", which represents the payment of the embedded benefit from suppliers to smaller EGs. This illustrative example outlines how this cost is calculated.



Consumer cost impact
Triad avoidance payment – Illustrative example

- The largest element of the consumer cost saving is the "Additional triad avoidance cost", which represents the payment of the embedded benefit from suppliers to smaller EGs. This illustrative example outlines how this cost is calculated.

Supplier X has 2GW of triad-chasing smaller EGs



Other scenarios

- In general, the larger the reduction in TDR, the larger the system and consumer cost savings.
- The "tipping point" in our analysis – at which new reciprocating engines are largely displaced by new CCGTs in the CM – occurred between Scenario 2 and the Generator Residual Scenario.
- The Generator Residual Scenario gives broadly similar results to Scenario 3.

Scenario	**System cost saving, £bn (NPV in £2016 real)**	**Consumer cost saving, £bn (NPV in £2016 real)**
Scenario 1	0.4	1.8
Scenario 2	1.4	5.2
Generator residual scenario	1.9	7.5
Scenario 3	2.1	7.4

Some conclusions

- TDR charges are currently creating distortions – removing them should lead to **higher social welfare** (lower system costs).
- Our results show that the proposed change to the TNUoS demand residual:
  - are likely to result in **lower system costs**
  - should result in **lower customer costs**, as saving in payments to EG very material
- Modelling of possible outcomes **should be treated with care** – it should not be the only basis for a decision.

Questions?

Limitations of this analysis

This presentation has been provided by Frontier and LCP. The results contained in this workbook are produced by LCP's model of the GB power market. The presentation contains projections under a scenario based on assumptions provided by publically available sources where possible and the client.

The results presented are dependent on the assumptions used and the modelling methodology applied. In particular, long term forecasts are subject to significant uncertainty and actual market outcomes may differ materially from the forecasts presented. We can therefore accept no liability for losses suffered, direct or consequential, arising out of any reliance on the results presented.

In particular:

The scenario presented does not take into account all changes that could potentially occur in the power market. More extreme market outcomes than those presented are therefore possible.

The relationship between the cost of generation and prevailing market prices has been assessed based on historical data and current forward power prices. To the extent that this relationship changes over time results could vary.

The modelling results are based on all market participants having a common view on future market outcomes. To the extent that views vary between market participants the results could be considerably different to those presented in this report.

The modelling makes use of a power plant database maintained by LCP which is based on publically available information where possible. Assumptions on individual plant characteristics have been estimated where required.

We do not take into account the effect that future changes to the market structure may have on the behaviour of market participants.

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