nationalgrid DSO

Distribution Network Options Assessment

Appendix A – Coordination of Load Related and Asset Replacement Expenditure

September 2024

Overview

The replacement of assets based on their condition is carried out across National Grid Electricity Distribution's (NGED's) four licence areas at every voltage level as part of the Asset Replacement Programme. The expenditure associated with this asset replacement cannot be deferred using the procurement of flexibility services as a reduction in the peak load of an asset does not have a significant impact on the condition of assets. There is, however, a need to embed whole system efficiency by using enhanced Distribution Network Operator (DNO) / Distribution System Operator (DSO) coordination to align load related activities with activities driven by other investment drivers.

When assets are replaced on their condition it provides an economic opportunity for uprating to be carried out in anticipation of future load growth, as the additional cost associated with installing higher rated assets while already carrying out works is far lower than the full cost of uprating an asset.

To illustrate this point an example scheme has been chosen (the replacement of both transformers at Melton Mowbray primary).

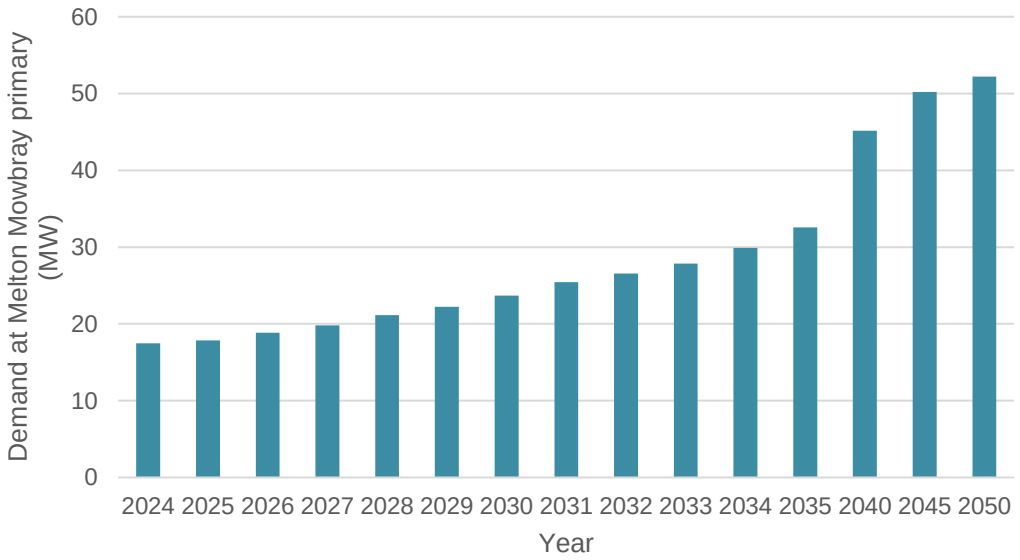
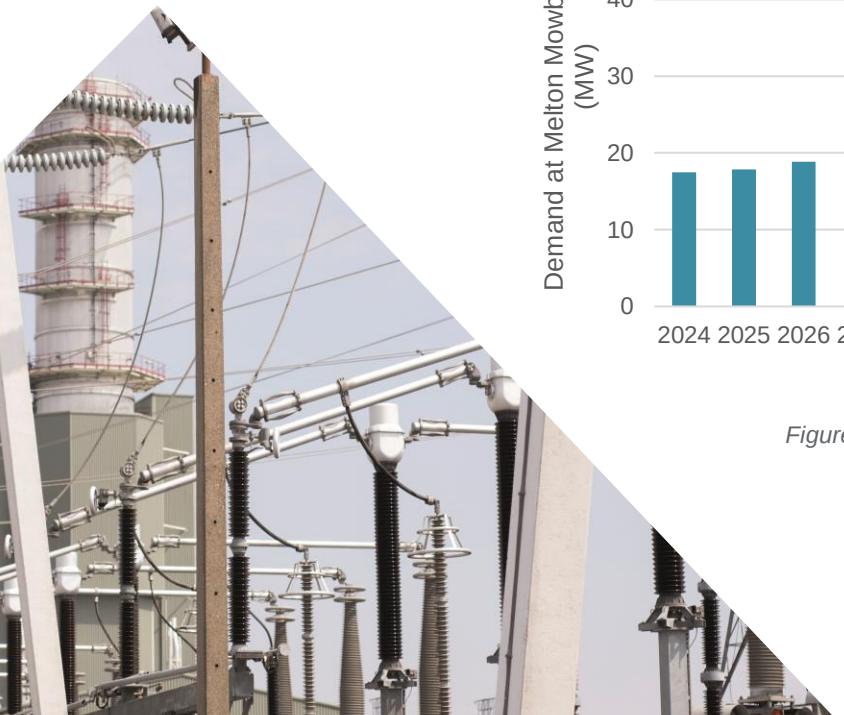


Figure 1 – DFES demand forecasts for Melton Mowbray primary



Example: Melton Mowbray primary substation

There are currently two transformers at Melton Mowbray primary both rated to 12/24 MVA. Both are scheduled for asset replacement within the RIIO-ED2 price control period (2023 to 2028) due to their condition, and the most cost efficient solution for the DNO would normally be to replace the transformers on a like-for-like basis, keeping capacity at 12/24 MVA. However, based on the forecasts in our Best View Distribution Future Energy Scenario (DFES) shown in Figure 1, if the assets were replaced like-for-like they would become overloaded around 2028, necessitating the installation of higher rated assets.

Options Considered

1) Replace transformers like-for-like using Asset Replacement allowances and later reinforce using general reinforcement load related allowances.
2) Replace transformers like-for-like using Asset Replacement allowances and then use flexibility to avoid reinforcement using general reinforcement load related allowances.
3) Replace transformers with uprated assets using Asset Replacement allowances.

Cost Benefit Analysis

The total cost for the replacement of these transformers with identical 12/24 MVA units would be around £1.2 million. The additional cost associated with instead installing 20/40 MVA units is only £156k. As noted above, the works to replace these transformers cannot be deferred using flexibility. It is however theoretically possible to defer the additional expenditure associated with installing higher rated units (in this case the extra £156k). A Cost Benefit Analysis (CBA) has been carried out to demonstrate why this is not practical nor economical. This CBA was carried out using the Common Evaluation Methodology (CEM) tool. The outputs of this CBA are summarised in Table 1 below. This CBA was carried out without the fixed costs of running flexibility zones considered; if these were included the ceiling prices calculated would be significantly lower. Additional demand which is planned to be transferred to Melton Mowbray primary from another site being decommissioned has also been excluded; if this was included the ceiling prices shown below would be even lower.

Table 1 – Utilisation ceiling prices and flexibility volumes required for the constraint at Melton Mowbray primary

Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Flexibility Utilisation Volume Required (MWh)	-	-	-	-	12	67	233	709	1,291	2,338	4,879	10,204
Utilisation Ceiling Price (£/MWh)	-	-	-	-	261	45	13	4	2	2	<1	<1

Example: Melton Mowbray primary substation

The ceiling prices in Table 1 show the value of flexibility per MWh to defer the £156k of expenditure which could be deferred if 12/24 MVA units were installed and flexibility then used to manage the consequent constraint. This shows that the ceiling prices drop to very low values after a few years due both to the high volume of flexibility required and the relatively small expenditure being deferred, continuing to decrease over time.

For the deferral of this expenditure to be viable, the constraint would need to be managed for the full lifetime of the assets (after which another opportunity to economically uprate the assets would present itself, i.e. when the asset is next due for replacement based on its condition). If enough flexibility could only be procured to manage the constraint for part of the asset's life then reinforcement would need to be triggered, with the full associated costs then incurred again. The deferral of this expenditure is therefore unfeasible both due to the low benefit of deferral (and therefore low ceiling price that could be offered) and the fact that there is no current way to guarantee flexibility for the 45 years or longer the asset would be expected to be in service.

There may be edge cases under which the deferral or avoidance of additional expenditure while carrying out asset replacement works using flexibility is possible. For example, if a spike in load is projected which is then expected to level off then a small amount of flexibility could allow smaller assets to remain unconstrained for the remainder of their lifetime. No examples of this being possible have yet been encountered but if they are they will be assessed individually to ensure flexibility is utilised if possible in accordance with our flexibility first commitment. It should also be noted that this would only be possible with a certain level of confidence in the future loading of the asset throughout its entire lifetime; and there is always an increasing degree of uncertainty the further out the forecasts go which could lead to a significant amount of option value being lost.

Recommendation

The three options considered all have different impacts on the balance of costs occurred between regulatory allowances and across current and future price control periods. The DSO is in a position to support optimisation of these costs and recommend to the business the most cost effective strategic action.

Options:

1) Replace transformers like-for-like using Asset Replacement allowances and later reinforce using general load related allowances. **Discounted**
2) Replace transformers like-for-like using Asset Replacement allowances and then use flexibility to avoid reinforcement using general load related allowances. **Discounted**
3) Replace transformers with uprated assets using Asset Replacement allowances. **Viable**

Implementing option 1 would lead to almost double the overall expenditure being incurred within the RIIO-ED2 price control period, along with the associated additional resource mobilisation and outages required to carry out works at the site twice. Option 2 has been discounted as utilising flexibility across the full lifetime of the asset is not feasible as discussed above (especially given the low value of deferral and consequent low ceiling prices which could be offered). Option 3 is the recommended reinforcement strategy for Melton Mowbray primary, and demonstrates the considerable savings which can be achieved by effectively coordinating load related activities with activities driven by other investment drivers (in this case Asset Replacement).

nationalgrid DSO

National Grid Electricity Distribution plc
Avonbank, Feeder Road
Bristol BS2 0TB
United Kingdom

nationalgrid.co.uk

September 2024. BLU28575/PR