

GD No. 2024/0123



MANX UTILITIES AUTHORITY PRICING REVIEW

November 2024

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BACKGROUND

In November 2016 the Treasury Minister announced he would be commissioning an independent review of Manx Utilities' financial position. Following the completion of this review, Tynwald received a report by the Treasury including a copy of the independent consultant's report in October 2017. At the same sitting of Tynwald it was agreed that Manx Utilities' debt due to Government (through the Consolidated Loans Fund) would be reduced by £95 million and Manx Utilities would undertake a review of its pricing strategy.

11. MUA Financial Long Term Plan

Motion made –

That Tynwald receives the Treasury Report on the Manx Utilities Long Term Financial Plan [[GD No 2017/0045](#)] and approves in principle the following recommendations:

1. The Treasury writes off £95 million of loans to the Manx Utilities Authority from the Consolidated Loans Fund;
2. The Manx Utilities Authority freezes the water rate at [341.8p/£] for the year 2018/19;
3. The Manx Utilities Authority freezes the sewerage rate at [98p/£] for the year 2018/19; and
4. The Manx Utilities Authority brings forward to Tynwald by October 2018 plans for a new pricing strategy for electricity, sewerage and water charges to:
 - a) More accurately reflect the costs of delivering services;
 - b) Provide a pricing framework for future price increases for transparency and protection of consumers; and
 - c) Ensure the continued financial stability of Manx Utilities and meet debt repayment schedules.

Mr Cannan

Motion carried.

The above four items were implemented at the time and the pricing strategy approved by Tynwald in October 2018 made provision for periodic review of the strategy. In December 2023 Tynwald approved an inflationary increase in the Sewerage Rate for 2024 and noted the significant volatility in wholesale energy markets over the previous two years and the extension of Manx Utilities' pricing strategy for a further 12 months is appropriate to enable further time for stability to return to the wholesale energy markets. The pricing strategy review has now been completed and support of it by Tynwald is sought.

Following an open tender process Economic Consulting Associates (ECA), economic utility specialist consultants, were commissioned to undertake a review of Manx Utilities' pricing strategy which underpins its Long Term Financial Plan (LTFP). ECA were selected due to their knowledge and experience of the economics of utility providers, access to benchmarking material and their work with Regulators in relevant jurisdictions. The 2018 pricing strategy was also supported by ECA following a competitive procurement process.

FINANCIAL REVIEW RECOMMENDATIONS

NERA REPORT CONCLUSIONS

Prior to the debt reduction approved by Tynwald in October 2017 the Treasury had commissioned NERA, an economic consultancy organisation, to undertake a review of Manx Utilities' financial position and financial forecasts. Since this time Manx Utilities has continued to monitor its financial position and performance against its Long Term Financial Plan (LTFP) that NERA had used to make its assessment.

Following the invasion of mainland Ukraine by Russia in February 2022 wholesale energy costs increased very significantly. This meant that the cost assumptions used for the LTFP were no longer appropriate and Manx Utilities engaged NERA, based on its previous work for the Treasury, to consider the changes required to Manx Utilities' financial forecasts and tariffs. NERA produced updated financial projections based on projected electricity demand and wholesale energy cost projections to determine the expected future revenues required to be raised to ensure that Manx Utilities can continue to provide appropriate and efficient utility services to its customers.

Essentially the work undertaken by NERA sets out the overall level of revenue that Manx Utilities should raise from its utility tariffs in order to be able to meet its costs as they fall due. NERA's reports were published on Manx Utilities' website at:

- Financial Review of Manx Utilities – 15 March 2023 <https://manxutilities.im/media/2624/nera-report-financial-review-of-manx-utilities-15-march-2023.pdf>; and
- Financial Review of Manx Utilities Updated Results – May 2023 <https://manxutilities.im/media/2641/may-2023-nera-review.pdf>.

PRICING STRATEGY REVIEW CONCLUSIONS AND RECOMMENDATIONS

ECA has completed its report (attached) and made a number of recommendations. Manx Utilities is supportive of ECA's report. In its review ECA has relied on the income projections that NERA produced during May 2023. As such, ECA has considered how the required income should be collected across various different tariff structures.

Manx Utilities has used ECA's report as the basis for its revised pricing strategy and the majority of its recommendations have been accepted in full or in part. Key recommendations within the ECA report which have been incorporated into the pricing strategy are:

1. Reviewing and setting of tariffs:
 - Periodic review period (5-yearly proposed), though an earlier review could happen if actual performance diverges appreciably from forecast
 - Formulaic approach to tariffs during each 5-year period, principally following general inflation and wholesale gas cost changes
2. Acceptance of the proposed, modified charging principles as recommended, but including reference to Government economic policy.
3. Electricity Tariffs:
 - Electricity tariffs to change in line with general inflation and wholesale gas cost changes
 - Keep current customer groupings (domestic, commercial and industrial)
 - Retain standing charge
 - Capacity and Demand (ASC and MD¹) charges not to be applied to the majority customers with electricity demand below 50kVA
 - Introduce universal Time-of-Use (TOU) tariff
 - High unit rates higher than standard unit rates for TOU tariffs
4. Water and Wastewater Tariffs:
 - Domestic water and wastewater charges continue to be charged on the basis of rateable value; no universal metering of domestic water supplies
 - Continue to reduce the discount to commercial premises
 - No changes to early settlement discounts offered
 - No changes to discounts for charitable and religious premises
 - Review policy of charging the higher of the Water Rate charge and the metered water consumption charge².

¹ Maximum Demand (MD) and Agreed Supply Capacity (ASC) charges are charges levied by electricity providers to secure supply capacity to meet customer demand (effectively reserving space on the network to meet a customer's electricity requirements).

² As specified in Schedule 6 3(3) of the Water Act 1991.

FUTURE PRICING STRATEGY

INTRODUCTION

The ECA report continues to recommend that reviewing tariffs every 3-5 years with annual adjustments based on a predetermined formula was most appropriate for Manx Utilities³. Within this period ECA considers that earlier, exceptional reviews should be undertaken for 'trigger events', as was seen with the energy crisis. This pricing strategy proposed the following approach:

- 5-yearly reviews to determine the target level of income for Manx Utilities (for the following 5-year periods) that protects customers by ensuring efficiency of costs, appropriate oversight and transparency whilst also confirming Manx Utilities' debt repayment obligations can still be achieved
- For the next five years overall income is based on NERA's revised income projections (reduced customer charges) following the debt reduction. Manx Utilities will make annual adjustments to the overall level of income based on annual general inflation and changes in wholesale gas prices
- Individual tariffs to be set by reference to seven pricing principles. The pricing principles ensure the objectives of those parties affected by tariffs are considered within the tariff setting process

This pricing strategy is intended to remain in place from April 2025 (2025-26) to March 2030 (2029-30). There are a number of recommendations where Manx Utilities is supportive of the recommendations, although further work is required to fully understand the impact of the changes. These recommendations include the introduction of universal Time-of-Use electricity tariffs, additional non-domestic water metering and wastewater metering based on metered water consumption.

OVERALL INCOME TARGET

Overall, the findings of the last NERA report⁴ showed that Manx Utilities' financial projections and underlying assumptions were reasonable and would enable the external Bond debt to be repaid as it falls due.

Manx Utilities proposes to work within the income projections set out in NERA's report for the period through to March 2031. Thereafter, Manx Utilities proposes 5-yearly reviews of these income projections and its underlying assumptions to ensure the protection of customers and the financial sustainability of Manx Utilities (significantly the repayment of the external Bonds). The scope for the review will include:

- the continued appropriateness of the objectives of the LTFP
- the reasonableness of updated forecasts in the LTFP (e.g. for demand and costs)
- an assessment of the financial sustainability of Manx Utilities under the plan
- recommendations for any changes relating to the above

³ Pricing Strategy Review, Section 5.

⁴ <https://manxutilities.im/media/2641/may-2023-nera-review.pdf>.

It is proposed that the next review will be undertaken during 2029 to cover the 5-year period commencing in April 2030. The review will be commissioned by Manx Utilities and its findings agreed with the Department of Infrastructure (Manx Utilities' sponsoring Department) and the Treasury. The review will be published and form the basis for Manx Utilities' charges for the five years to March 2035.

ANNUAL INCOME ADJUSTMENTS

Within the initial 5-year period to March 2030 it is proposed that Manx Utilities' overall income is allowed to change with reference to the following:

- Annual increases for general inflation, based on the Isle of Man 12-month Consumer Prices Index (CPI) published in October each year
- Adjustments to electricity tariffs for changes to wholesale gas prices, to the extent that these changes cannot be mitigated
- Reduction of the discount of Water and Sewerage Rates for non-domestic customers, with the discount reducing from the current 25% by 5% per year to 0%

Whilst the energy crisis has led to significant financial pressures on both Manx Utilities and its customers, seeking to link tariffs to annual inflationary changes will provide certainty to customers that significant price increases will not occur unless there are exceptional changes to wholesale market prices. This also means that the majority of tariffs will not increase in real terms during this period. It remains Manx Utilities' intent to reduce electricity tariffs when wholesale energy prices reduce further.

An annual review of tariffs has been undertaken over the last six years and will continue to be undertaken and published; tariff changes will commence from 1 April each year with the review being published before the end of the preceding December.

Manx Utilities is committed to working to providing customers with stable prices however the risk remains that significant unexpected external events may occur, which may trigger the need to review this approach. In such a case, Manx Utilities will approach the Treasury to set out the issue and offer alternative proposals for consideration.

PRICING PRINCIPLES

Within the overall level of income required to protect customers and ensure the continued financial sustainability of Manx Utilities it is necessary to set individual tariffs to achieve the appropriate overall level of income. Manx Utilities has previously used pricing principles to modify tariffs and these have been reviewed and updated. Changes to pricing principles arising from this pricing strategy review are as follows:

- ***Cost Reflective*** renamed to ***Economically Efficient***. This change recognises that supply and demand patterns are changing, and are expected to continue to change, as a consequence of climate change and initiatives to reduce greenhouse gas emissions; and
- ***Simple and Transparent*** renamed to ***Customer Choice***. This change recognises that some customers (such as *prosumers*) are interested in becoming more engaged with their utilities' suppliers for mutual benefit, and that their needs may not be met through traditional basic tariff offerings.

The updated pricing principles are also intended to provide greater transparency and protection of customers for the next five years:

- **Customer choice** – charges, and the approach to setting charges, should be simple, transparent and easy to understand in the main, but some customers will be more engaged with their utility usage and will seek out more complex tariffs
- **Stable** – charges, and the approach to setting charges, should be stable (with changes in charges implemented smoothly over time)
- **Non-discriminatory** – there should be no undue discrimination between customers, with customers having similar characteristics facing similar charges
- **Encourage efficient consumption** – charges should encourage efficient consumption decisions by consumers
- **Economically efficient** – consumers' charges should reflect the costs they impose, unless justified by other charging principles, but also react to and encourage changes to patterns of supply and demand
- **Consistent with Isle of Man Government's policy** – charges should be set mindful of Isle of Man Government's social, economic and environmental policies
- **Cost recovery** – charges should be set to provide a reasonable prospect of the recovery of costs

ECA note that occasions will arise when individual principles conflict with each other and judgement will be required to determine how the principles will be applied. However, the principles will continue provide an appropriate framework for assessing changes to individual tariffs (and the establishment of new tariffs) and ensure income is fairly distributed between tariffs.

ELECTRICITY TARIFF DESIGN RECOMMENDATIONS

ECA has included electricity tariff design recommendation within Section 3.8 of their report. Table 12 of their report sets out recommended levels of individual tariffs based on the economic analysis undertaken by ECA using methodologies applied for regulated tariffs in other jurisdictions. Such changes include significant increases to standing charges (from 24.6 pence per day to 44.8 pence per day) that would ensure standing charges cover more of the cost of a customer being connected to the electricity supply network. This is also more comparable to the levels of standing charges elsewhere, such as those set out in OFGEM's Default Tariff Cap.

However, it is also accepted that such changes to standing charges would have a significant adverse impact on some customers, and potentially this would affect low income customers (who are more likely to consume lower quantities of electricity) more than other customers. As such it is not proposed to automatically adopt the tariff levels proposed within the report.

Further work is required to understand the impact of the proposed changes on customers although the underlying economic principles applied by ECA are supported by Manx Utilities. For example, currently customers adopting TOU tariffs will lower their costs due to gaining access to a lower rate of electricity for some of the day. This is due to the higher rate of electricity they are charged for the remainder of the day being the same rate as the standard rate they would have been charged prior to changing to a TOU tariff. As such, tariff restrictions are required to be applied to current TOU tariffs. It is proposed that Manx Utilities will introduce new TOU tariffs without such restrictions but where the higher charges are more expensive than the equivalent single-rate tariff charges so that customers can choose a TOU tariff and then adapt their consumption behaviour for mutual gain.

Similarly, the previous pricing strategy and the current pricing strategy have both drawn attention to the relatively high unit rate that Manx Utilities pays to customers with surplus renewable private generation. Work is proposed to provide a methodology for setting this unit rate that will be able to be applied on an ongoing basis.

Further work is required to understand the impact of such changes on customers and determine how any changes are best introduced. This may include phasing changes in over time or creating new tariffs and retaining existing tariffs for current customers only. **This further work is proposed to be completed by October 2025.**

FURTHER WORK TO BE INVESTIGATED

Significant work has been undertaken in respect of the pricing strategy review but the impacts on customers and Manx Utilities of some of the recommendations made by ECA are not fully understood. As such, it is appropriate to take additional time to undertake further assessments. Recommendations made by ECA requiring further consideration are as follows:

Electricity

Merge Maximum (MD) and Agreed Supply Capacity (ASC) charges – the rationale for separate MD and ASC charges is that each charge theoretically has a different impact on customer behaviour however this does not seem to be borne out in practice. Combining MD and ASC charges into a single agreed supply capacity charge would simplify billing for both customers and Manx Utilities. As such this recommendation is supported but further work is required to implement this change. **This further work is proposed to be completed by July 2025.**

Introduce MD/ASC for sustainable generation customers – sustainable generation customers who install private renewable generation and retain their connection to the electricity supply network can currently reduce their charges to an amount below the cost of Manx Utilities maintaining their supply connection. This means these customers can reduce their costs of electricity from their private renewable generation but still have a guarantee of electricity at all times. The MD and ASC charges apply a charge for having access to the electricity supply, whether it was being used or not. Whilst applying such charge (a combined MD/ASC is assumed) to smaller customers can increase billing complexity, these customers will generally be more interested and better informed about electricity charges. Therefore, the recommendation for this is accepted subject to further work being completed. **This further work is proposed to be completed by October 2025.**

Changes to TOU times – for many years TOU tariffs have allowed customers to access cheaper electricity overnight when demand often drops. This has resulted in tariffs with higher unit rates for the majority of each 24-hour period and lower unit rates for fewer hours. More recently the impact of peaks in electricity demand have been more relevant and customers have been encouraged to move consumption away from those peak demand times. Many electricity suppliers are therefore offering TOU tariffs with a low unit rate for the majority of each 24-hour period with a higher rate for fewer hours around demand peaks. 3-rate and other multi-rate tariffs are also now possible with digital and smart meter technologies. Such tariffs offer customers more choice to change their consumption to reduce their energy costs. The recommendation to change the time periods and unit rates on TOU tariffs is supported although further work is required to propose time periods and unit rates relevant for the Isle of Man. **This further work is proposed to be completed by July 2025 with a view to introduce the tariff during 2025-26.**

Mandatory TOU tariff for large (industrial) customers – larger customers have a more significant impact on the electricity system and TOU tariffs have been found to be effective in changing customer behaviour to make more efficient use of the electricity supply system. Again, this recommendation is accepted in principle, although further work is required to understand the potential impacts of the change and to best identify how this change should be introduced. **This further work is proposed to be completed by April 2027.**

Sustainable Generation tariffs (private renewable generation tariffs) – customers who install private generation generally have lower quantities of electricity supplied to them and the low daily standing charge means that the revenue generated from these customers does not cover the cost of maintaining the electricity connection to their property. Consequently, other customers are effectively subsidising these costs. ECA has proposed a capacity charge is applied to these customers. Initial assessment has considered whether this is applied through a higher daily standing charge or a form of MD or ASC charge. Further work is required to determine how this should be applied to customers installing private generation but still requiring the reliability of a permanent connection to the island's electricity supply network. These customers also receive payments from Manx Utilities for surplus electricity exported to the island's electricity supply network and, at times, this payment has been significantly higher than the value of the electricity received. It is proposed that a mechanism to periodically review and align the payment to the value of electricity is introduced to avoid indirect subsidy from other customers' bills. **This work is proposed to be completed by September 2025.**

Social tariff considerations – the cost-of-living crisis has shown the need for tariffs better targeted at those who are struggling to pay for their energy usage. Social tariffs by their nature are subsidised by other customers and so the more customers given access to a discounted tariff means either the level of discount needs to be lower or the tariffs for other customers need to be higher. The main challenge with such tariffs is how customer need is assessed, and the costs of performing this function. The social security benefits system is intended to ensure minimum levels of financial security. Tariffs can be linked to specific social security benefits providing appropriate data sharing agreements are in place; alternatively additional funding contributions can be made for distribution through the social security benefits system. It is proposed that further research into options for social tariffs is undertaken. **We will have initiated discussions with the Treasury and the Department of Health and Social Care by April 2025.**

Dynamic pricing – more engaged customers can have a particularly good understanding of their requirements and how to minimise their costs through changing their behaviours or using batteries to store electricity at certain times. Such customers can change their demand requirements to when electricity is cheaper or when their demand will have a lower impact on the electricity supply system. Dynamic pricing, including real-time pricing, can encourage such behaviour changes and so this recommendation is supported, although at this time is considered a lower priority than other recommendations requiring further work. **This further work is proposed to be completed by April 2029.**

Water

Introduce standing charges – initial economic assessment suggests that a standing charge for water may be low and so the benefits of introducing a standing charge may not be sufficient for changes needed to introduce the charge and inform customers of the changes. As such, this recommendation is not supported initially but will be reviewed further, especially alongside other potential changes in respect of water metering. **This further work is proposed to be completed by June 2026.**

Cost Benefit Analysis for water metering – Manx Utilities has been preparing a Water Resources Management Plan (WRMP) in response to changes in weather patterns and the need to protect our Island's water stocks throughout the year. Water metering is considered a key enabler of customers being encouraged to reduce their consumption through minimising wastage and is likely to be recommended as part of the WRMP. Previous cost benefit analysis has considered the direct costs of water production, but it is proposed that the costs of additional potential water resource assets that would otherwise be required are included in the cost benefit analysis. **This further work is proposed to be completed by June 2025.**

Wastewater

Water metering used for wastewater charging – the basis for the recommendation is accepted although the currently limited deployment of water meters means it is not possible to make widespread use of metering for wastewater charging. The recommendation will be considered further with the relative proportions of foul and surface water contributions needing further research. **This further work is proposed to be completed by June 2026.**

Trade effluent charging – further assessment of the current trade effluent licensing regime is required to determine the impact of separate trade effluent charging arrangements. **This further work is proposed to be completed by June 2026.**

Strategy review

Quarterly tariff reviews – the recent volatility in wholesale energy markets have led to volatile costs for Manx Utilities. Quarterly tariff reviews (the same frequency as currently adopted by OFGEM for its Default Tariff Cap) enable cost increases and reductions to be passed on to customers more quickly. However, the underlying volatility of energy markets is also passed through to customers as a result, and so customers have less stability and certainty of their charges. This recommendation will be investigated further although Manx Utilities' preference is to have annual tariff changes. **This further work is proposed to be completed by April 2025.**

PROPOSED CHANGES TO TARIFFS

No significant changes to tariffs are proposed for April 2025:

- Annual increases for general inflation, based on the Isle of Man 12-month Consumer Prices Index (CPI) published in October each year
- Adjustments to electricity tariffs for changes to wholesale gas prices, to the extent that these changes cannot be mitigated. It is hoped reductions to tariffs can be applied when wholesale energy costs reduce
- Reduction of the discount of Water and Sewerage Rates for non-domestic customers, with the discount reducing from the current 25% by 5% per year to 0%

The financial projections provided to NERA (from the LTFP) for its work made the following broad assumptions in respect of tariff increases:

- Electricity tariffs to increase based on general price inflation and gas price inflation;
- Water tariffs to increase based on general price inflation;
- Wastewater tariffs to increase based on general price inflation.

RECOMMENDATIONS

The pricing strategy approved by Tynwald in October 2018 has provided customers with certainty, transparency and stability of water and wastewater tariffs over the last six years whilst supporting progress towards Manx Utilities repaying its Bond and other debt for water, wastewater and electricity. It is regrettable that the significant changes in wholesale energy costs in recent years has required some exceptional increases to electricity tariffs, and therefore stability of electricity tariffs has not been achieved in recent years. Manx Utilities' energy forward purchasing (hedging) strategy helped reduce the impact of the market increases and such forward purchasing of energy continues during the current challenging market conditions so that similar protections are in place if required in the future.

Manx Utilities remains on course to be able to repay the Bonds when they fall due, and it should be noted that the first £75 million of Bond repayments is due in March 2030 at the end of this 5-year period. The focus of the updated pricing strategy continues to seek to meet the aims of the previous strategy of ensuring costs are recovered, providing transparency in tariff setting, providing protection for consumers against excessive tariffs and providing financial stability for Manx Utilities.

The pricing strategy can be summarised as follows:

- 5-yearly reviews to determine the target level of income for Manx Utilities (for the following 5-year periods) that protects customers by ensuring efficiency of costs, appropriate oversight and transparency whilst also confirming Manx Utilities' debt repayment obligations can still be achieved;
- For the first 5 years overall income is based on NERA's revised income projections (reduced customer charges) following the debt reduction. Manx Utilities will seek to keep annual adjustments to the overall level of income by reference to annual general inflation and changes in wholesale gas prices;
- Individual tariffs to be set by reference to 7 pricing principles. The pricing principles ensure the objectives of those parties affected by tariffs are considered within the tariff setting process;

In order to support the pricing strategy, Tynwald is requested to receive this Pricing Strategy and:

1. Approve Manx Utilities' proposed pricing strategy for the next five years, including the report prepared by ECA, to achieve an appropriate balance between the financial sustainability of Manx Utilities and the impact utility charges have on customers
2. Approve a Sewerage Rate for the financial year commencing on 1 April 2025 of 270.7 pence in the pound plus the prevailing rate of inflation over the preceding 12 months as measured by the Manx Consumer Price Index to September 2024
3. Approve further Sewerage Rate increases for 1 April 2026, 1 April 2027, 1 April 2028 and 1 April 2029 at the prevailing rate of inflation over the preceding 12 months as measured by the Manx Consumer Price Index to the September of the preceding year



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Consultancy services on a Pricing Strategy Review

Final report

11 November 2024

Submitted to **Manx Utilities**

ECA



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Abbreviations and acronyms

ASC	Agreed Supply Capacity
BAU	Business-as-usual
CBA	Cost Benefit Analysis
CPI	Consumer Prices Index
DAM	Day-Ahead Market
DER	Distributed energy resources
ECA	Economic Consulting Associates
EV	Electric vehicle
GEL	Guernsey Electricity Ltd
LCT	Low-carbon technologies
LRAIC	Long-run average incremental cost
MU	Manx Utilities
SEM	Single Electricity Market
TOU	Time-of-use
UR	Utility Regulator
WTW	Water treatment works

1 Introduction

Economic Consulting Associates Ltd (ECA) have been contracted by Manx Utilities (MU) to develop a Pricing Strategy Review of MU's customer tariffs for electricity, water and wastewater. The new Pricing Strategy Review follows the end of the intended five-year pricing period for the previous (and first) iteration undertaken by ECA in 2018.¹

The objective of the review is to assess the current tariff schedule with regards to MU's pricing principles, critically evaluate the pricing principles themselves, and provide a set of recommended amendments to the tariff designs and levels that meet MU's financial objectives and make due regard for the sector developments. MU's financial needs are set out in a financial review undertaken by NERA in 2023, which estimates MU's required revenues to meet demand and supply forecasts for the coming five-year period and beyond.²

This report details our assessment and the recommendations derived. It is structured as follows:

- **Section 2** reviews the current pricing principles considering any potential amendment driven by developments in the sector since the last Pricing Strategy Review as well as mechanisms for managing conflicts.
- **Section 3** reviews the tariff design for electricity pricing with respect to the pricing principles, addressing issues for all customer categories and providing a recommended new tariff schedule detailing their proposed components and levels as well as impact on key customer groups.
- **Section 4** provides a similar review of tariff design and set of recommendations for water and wastewater charges.
- **Section 5** provides recommendations for updating tariffs over time building on those employed following the previous Pricing Strategy Review.

¹ ECA. 2018. [Pricing Strategy Review: Final Report](#)

² NERA. 2023. [Financial Review of Manx Utilities](#)

2 Pricing principles

2.1 Current pricing principles

Following the 2018 Pricing Strategy Review undertaken by ECA, MU adopted the recommendations provided in the report. This resulted in the current set of pricing principles which are detailed in Table 1 below.

Table 1 Current pricing principles

Principle	Description
Simple and transparent	Charges, and the approach to setting charges, should be simple, transparent and easy to understand
Stable	Charges, and the approach to setting charges, should be stable (with changes in charges implemented smoothly over time)
Non-discriminatory	There should be no undue discrimination between customers, with customers having similar characteristics facing similar charges
Encourage efficient consumption	Charges should encourage efficient consumption decisions by consumers
Cost reflective	Consumers' charges should reflect the costs they impose, unless justified by other charging principles
Consistent with government policy	Charges should be set mindful of government's social and environmental policies
Cost recovery	Charges should be set to provide a reasonable prospect of the recovery of costs

Source: Manx Utilities Authorities. 2018. Pricing Review

These principles are aligned with international norms and best practice. As part of a recent review ECA undertook for network pricing across 24 European countries, the most commonly cited principles were cost recovery, transparency, cost reflectivity, and avoiding cross subsidies.³ Similarly, the current pricing principles are consistent with the Bonbright Principles of Public Utility Rates that have historically driven pricing strategy design considerations in the United States.⁴

Given the starting point is therefore alignment with best practice in 2018 our current review focuses on:

- Any changes that have taken place in the sector subsequent to 2018 that may justify a reconsideration; and
- Any difficulties cited by MU in application of the current set of principles.

³ ECA. 2022. [Study on regulatory approaches of electricity TSO and DSO network tariff structures among ERRA member organisations](#)

⁴ Bonbright C. 1960. [Principles of Public Utility Rates](#)

2.2 Implications of sector developments

The most relevant change in the sector relates to the increased importance of distributed energy resources (DER). The increased prevalence of DERs, including rooftop solar PV (RSPV), electric vehicles (EVs), and controllable heat pumps, holds the potential to both change demand patterns and provide residential consumers with the ability to interact more proactively with their energy use. DERs offer potential alternatives to utility generation, load control options for system operation, and non-network solutions for grid congestion. Conversely, dependent on tariff design, they can create revenue shortfalls for the utility which are recovered from non-participating consumers and an effective cross-subsidy. With regards to the pricing principles:

- **“Simplicity”** may not be desirable for highly engaged consumers to the extent it results in a constraint on their ability to maximise the utility of their DER. This criterion may therefore be expanded to a broader one of **“customer consent”**, reflecting that different customers have different levels of understanding, engagement, and resources.
- **“Cost reflectivity”** may have an increased need to consider reflecting the benefit of promoting innovation and change in response to changing contexts. To encompass this requirement the principle may be re-termed **“economic efficiency”**.

2.3 Potential conflicts and considerations

There are a number of areas where these principles can come into potential conflict with one another. The key areas of concern are:

- **Cost recovery versus stability:** Some operating costs outside of the control of MU may vary significantly within and between years. The longer the period between tariff amendments (for reasons of tariff stability) the greater the potential for short run divergence between reasonable cost recovery requirements and actual revenues.
- **Cost recovery versus cost reflectivity / economic efficiency:** Recovering historic (residual) costs has the potential to distort cost reflective price signals.
- **Cost reflectivity / economic efficiency versus social and environmental policy:** Governments and regulators may wish to use tariff frameworks to encourage certain actions such as energy efficiency or uptake of low-carbon technologies. They may also wish to support vulnerable consumers. These objectives can lead to divergence from cost reflective tariffs.
- **Cost reflectivity / economic efficiency versus simplicity / customer consent:** A more cost reflective tariff design can require a more complex one with time-of-use (TOU) and a multi-part framework (volumetric, demand charges, fixed charges, and reactive power charges) being incorporated. Furthermore, such designs can increase the price risk borne by consumers who may be unable to either understand or respond with confidence to the different price signals.

Managing the right balance between conflicting principles is a matter of judgement and will be case specific, making it difficult to set any form of designated weighting or prescriptive process. Nevertheless, a high level two step framework can be considered as follows:

- **Cost recovery** cannot be compromised beyond the short run as it is essential that MU remains financially viable. This is supported by the Electricity Act 1996, Water Act 1991, and Sewage Act 1999.
- **Cost reflectivity / economic efficiency** should then be maximised subject to sufficiently justified compromises arising from measurement limitations and/or conflict with **other principles**, in particular those regarding **policy** objectives and **simplicity / customer consent**.

2.4 Recommendations

The current pricing principles are consistent with international best practice and our recommendation is to retain these in their current form with the exception of the following amendments to better account for the changes observed in the sector since the last Pricing Strategy Review (particularly for electricity):

Table 2 Proposed amendments to pricing principles

Previous term	Proposed replacement term	Rationale
<i>Simple and transparent</i>	Customer consent	• Reflects desire among some consumers to engage more proactively with energy use. • Reflects different perspectives on willingness to bear price risk.
<i>Cost reflective</i>	Economically efficient	• Encompasses “dynamic efficiency” regarding need for innovation at a time of changing supply and demand patterns.

Source: ECA

3 Tariff design – electricity

The unit rate tariffs and standing charges for electricity supplied by MU as of June 2024 are reproduced in Table 3 below.

Table 3 Electricity tariff unit rates and standing charges

Tariff	Unit charge (p/kWh)		Standing charge (p/day)
	Daytime	Nighttime*	
Domestic			
Domestic and prepayment		28.5	24.6
Basic domestic		28.5	71.6
Domestic Comfy Heat	28.5	16.7	24.6
Electric vehicle	28.5	19	24.6
Sustainable generation**		-9.5	24.6
Commercial			
Standard commercial	28.5		24.6
EVs commercial	28.5	19	24.6
Commercial plus	28.5	16.7	24.6
Economy 8 commercial	28.5	18	24.6
Industrial			
Industrial demand	25.7		42.9
Economy 8 demand	25.7		42.9
High load factor		19.2	42.9
High volume	24.4		42.9
High volume 2 rate	24.4	18	42.9
Public lighting		27.6	0
Guaranteed green tariff	+1.5	+1.5	N/A

* The designated time-time period varies by two-part tariff

** payment for electricity units sold to Manx Utilities

Source: Manx Utilities. 2024. [Tariffs, rates and charges](#)

For industrial customers with a maximum demand in excess of 50 kVA, a Maximum Demand charge and an additional Agreed Supply Capacity (ASC) charge based on the customer's required capacity are applied as detailed in Table 4.

Table 4 Demand and capacity charges for industrial customers

Monthly Demand (£/kVA/month)	Agreed Service Capacity (£/kVA/month)	Reserve Demand* (£/kVA of generation/month)
2.76	1.51**	4.29

* Applies to industrial customers with private generation

** A penalty rate of £32.50/kVA/month is applied for exceeding the ASC
Source: Manx Utilities. 2024. [Tariffs, rates and charges](#)

3.1 Approach

In considering tariff design for electricity, we have followed the two step framework given in Section 2:

- Ensuring **cost recovery** (the trade-off with **stability** is considered further in Section 5 on the updating of tariffs).
- Achieving maximum **economic efficiency** through cost reflective tariffs unless where other principles justify divergence with particular regards to:
 - **Customer consent**
 - **Social and environmental policy**

In addition, where the argument for change is not clear, we are led again by the principle of **stability** to favour retaining the existing tariff design.

The discussion therefore is structured as follows:

- **Section 3.2** describes the formation of electricity costs and how the allocation of the costs aligns with the selection of customer categories.
- **Section 3.3** describes the five core forms of electricity charges and their purpose.
- **Section 3.4** covers how costs that vary with peak demand (“demand-driven”) may be reflected in the various tariff types for each customer category, including special tariffs. How trade-offs with principles of customer consent and policy matters may be treated by customer category are discussed here.
- **Section 3.5** covers how costs that scale by customer numbers may be best reflected for each customer category.
- **Section 3.6** discusses variable costs driven by the volume of electricity consumed including consideration of TOU tariff designs for each customer category.
- **Section 3.7** briefly discusses reactive power charging and penalties.
- **Section 3.8** then brings together the prior discussion and summarises recommendations for amendment.

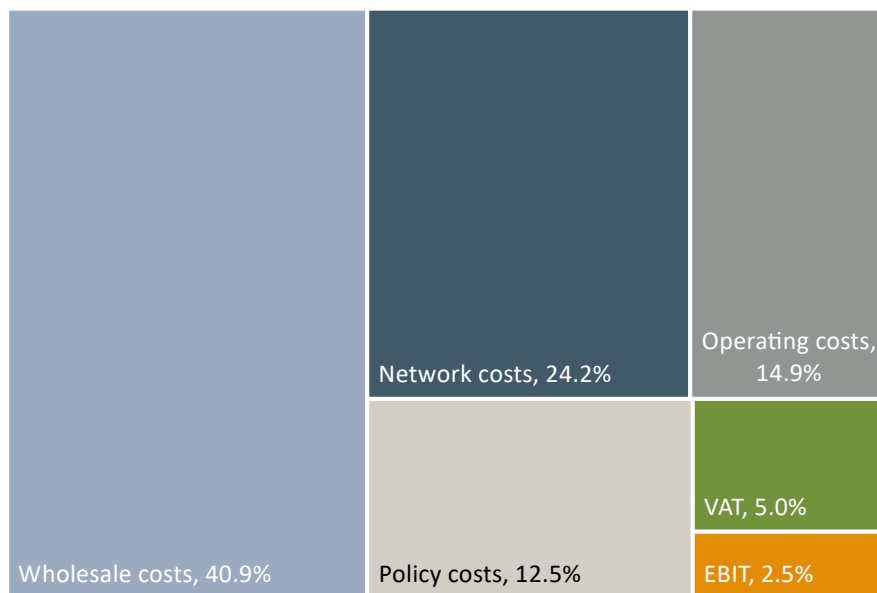
Issues regarding **special tariffs** to address social and environmental policy considerations are embedded in the sub-section discussions.

3.2 Cost allocation and customer categorisation

3.2.1 Cost breakdown

Electricity costs are made up of wholesale costs (cost of generation / imports), network costs, supplier operating costs and margin, any environmental and social levies, and tax. An example breakdown as provided by Ofgem for Great Britain is given in Figure 1.

Figure 1 Breakdown of core costs for Ofgem price cap



Note: Allowances and adjustments of relevance to the price cap setting process have been excluded from the calculation

Source: Ofgem data portal, costs included in price cap level: payment by Direct Debit, July-Sept 2024

Excluding policy costs and taxes, the remaining costs are split approximately 50% on wholesale costs, 30% on network costs, and 20% on supplier operating costs and margin. The main cost driver for each portion varies:

- Wholesale energy costs** have historically been largely volumetric (ie per kWh) with the cost of fuel being the key component. This is changing as more fixed cost orientated variable renewable generation is brought on to the system. Nonetheless, the large majority of generation costs remain recovered through the wholesale energy markets which utilise volumetric pricing.⁵
- Network costs** are overwhelmingly fixed and driven by capacity requirements to meet peak demand (ie per kW) on the system. Nevertheless, historic costs do not necessarily reflect current or future demand. This is an issue explored further below.

⁵ While MU are vertically-integrated with their own generation, such generation can trade across the interconnector in the GB market and hence the volumetric trading price is the reference point for wholesale energy costs

- **Supplier operating and margin costs** are largely driven by the number of customers (ie per customer).

MU's accounts are bundled as an integrated entity and hence a like-for-like comparison is difficult. Figures provided in the financial model indicate for 2022-23 around 52% of annual expenditure was expected to be on wholesale energy and associated overheads (the latter being predominantly interconnector fees), around 27% on financing and depreciation costs, and around 21% on employment costs and other overheads. Financing and depreciation costs relate to fixed assets of which around 40% of electricity assets are associated with the network (interconnector and distribution system). The remainder of electricity sector fixed assets are related to electricity generation facilities and gas pipeline systems.⁶

The share constituted by wholesale energy and associated overheads is expected to fall over the coming five years in line with a general decline in global energy market prices. Meanwhile significant new investments in fixed assets, notably a new interconnector and a renewable energy generation facility, are projected to see financing and depreciation costs rise significantly by 2030. The net result is wholesale costs are forecast to fall to 31% and financing and depreciation costs increase to 43% of total expenditure.

3.2.2 Allocating costs

Wholesale electricity costs are common to all consumers and therefore no differentiation in allocating costs by consumer category is justified on the grounds of cost reflectivity.⁷

Network costs in contrast can differ dependent on the connection point of the consumer. MU's grid network operates at three principal voltage levels: 33 kV ("transmission"), 11 kV ("HV distribution")⁸ and 0.4 kV ("LV distribution"). In a traditional system, consumers connected at each voltage level can be considered to only impose infrastructure costs upstream of their connection point. For this calculation step-down transformers are considered part of the infrastructure associated with the lower voltage side of the step-down.

Such allocation reflects that electricity supply is generally stepped down from transmission. However, this is not a perfect indicator of the cost of supply given the density of connections will vary greatly across the network even at a common voltage. Furthermore, distribution system connected generation does hold the potential to cause reverse flows in some locations (ie upstream from a lower to a higher voltage) although this remains comparatively rare and is not understood to be an immediate concern for the Isle of Man.

As was the case at the time of the previous Pricing Strategy Review, among comparator jurisdictions reviewed, Guernsey, Jersey and Cyprus all differentiate non-commercial customers by voltage (11 kV and 0.4 kV connected respectively) while Alderney and Malta do not.

MU continue to differentiate customers instead based on consumption volume, load factor, and peak demand (eg the "High Volume" tariff for those with consumption exceeding 1,000 MWh per year). The categories have significant cross-over with any voltage level differentiation. High Volume and High Load Factor are understood to be exclusively connected

⁶ Manx Utilities Financial Model – Update, provided by Manx Utilities to ECA 8 April 2024

⁷ This does not cover losses which differ by connection point.

⁸ We understand there are also a small number of 3.3 kV lines that may be considered aggregated with the 11 kV network for this discussion

at HV level, while Industrial Demand and Economy 8 Demand customers are predominantly connected at LV level (those connected at HV also have a separate tariff code applied). The current framework therefore already largely allows for designating tariffs by voltage level and so **led by the principle of stability, we do not recommend an amendment on this basis.**

Treatment of demand charges and TOU charges, and the implications for the set of tariff options offered is considered further in the following sections.

3.2.3 Categorisation due to other factors

Consumption profile

Domestic and non-domestic consumers tend to have a notably different average consumption profile. For domestic consumers there are clear evening and morning peaks with a trough during the daytime while residents are at work locations, and low consumption during nighttime. Offices, retail and construction will usually see a flatter daytime peak during typical working hours. Restaurants, hotels and bars are more aligned to domestic consumers with an evening peak. Industry, dependent on sector, can present a flatter more consistent profile that continues through nighttime when processing is possible for 24 hours a day.

Given the historical limitations with metering capacity and ability to implement TOU tariffs, categorising consumers broadly by consumption profile – typically into domestic, commercial and industrial – can approximate the different costs of supply. More granular breakdown, such as for different types of commercial premise, are not recommended as they can be difficult to verify and risk ‘gaming’ by consumers.

Metering capabilities

The tariff structure imposed to each customer class may differ due to billing and metering constraints. For example, standard electromechanical meters do not allow readings for TOU charges or may only allow for coarse granularity (eg split into daytime and nighttime). Meters can also differ in their ability to record maximum demand and reactive power consumption. However, MU are engaged in a comprehensive rollout of smart meters which is expected to continue for another 2-3 years before completion. The rollout helps negate the need to categorise consumers by their technical ability to measure usage patterns and consumption profiles. However, differentiation may still be justified for reasons of consumer consent and social policy.

Consumer consent

The current pricing principle of **simplicity** reflects that consumers can only respond to price signals to the degree they understand the concepts and can be reasonably expected to have control over usage patterns. Where consumers are likely to either not understand the price signals or not be able to respond accurately to them, the tariff design will no longer be economically efficient. This issue is most acute for domestic consumers where poorly implemented and communicated designs in other jurisdictions have led to consumers unwittingly incurring extremely high charges. A recent example can be seen in Australia where utilities have applied maximum demand charges to consumers seemingly unaware they had

been moved to a tariff with such a structure.⁹ Similarly, reactive power consumption is a difficult concept for many small consumers to comprehend and be able to manage.

Demand and reactive power charges are discussed further in the following sub-sections. However, the Australian experience supports the categorisation of customers by their perceived ability to understand and respond to complex cost reflective tariffs designs. Such categorisation can take the form of type of consumer category (domestic, commercial, industrial) and/or their size in terms of volume or maximum demand.

A final consideration with respect to **consumer consent** is the willingness to accept price risk. In many markets such as mortgages and insurance, customers can hedge their price risk (possibly down to a single fixed rate) for a premium. The same logic may be applied to the energy market providing customers with the choice to opt-in to more complex tariff designs with variable pricing at their own risk.

Social policy

A further rationale to separate customer categories, in particular domestic from non-domestic, is the ability to route any specific social or environment policies through the tariff design that would only apply to those customers. Social tariffs rates are a common feature of electricity markets globally. The choice whether to implement one is a social policy matter and beyond the scope of this report. However, if the decision has been taken to provide support to low income or vulnerable consumers through electricity tariffs (as opposed to via the welfare system) then for efficient implementation we recommend the adoption of a specific tariff category with clear eligibility requirements derived from existing welfare structures. This may take the form of a reduced unit rate and/or standing charge as opposed to a block tariff approach (see Section 3.5 for further discussion).

Scheme design varies greatly by jurisdiction and there is little apparent consensus on the best approach. For example:

- In **Great Britain** the Warm Homes Discount (WHD) provides eligible households with a £150 reduction in their annual energy bill. It is required to be offered by all suppliers with at least 1,000 domestic customers and is recovered from all customers.¹⁰ There have, however, been calls for more a more wide-ranging social tariff although no consultation has yet been issued. It is not clear how any such tariff would differ from the WHD although reduced unit rates and standing charges as opposed to a lump sum payment have been suggested.
- In **Belgium** the regulator sets the social tariff each three months with reference to:
 - **Energy component:** The lowest commercial tariff offered by energy suppliers during the month preceding that quarter.
 - **Distribution component:** The lowest distribution network tariff offered in the Belgian distribution areas during the month preceding that quarter.

⁹ ABC News. 2024. [Energy retailers' 'insidious' power pricing charges households based on highest point of use - ABC News](#)

¹⁰ Ofgem. Accessed 2024. [Warm Home Discount](#)

- **Transmission component:** Takes into account the Elia/Fluxys (Belgian system operators) transmission tariffs.

The calculated result is then capped to be no more than either 10% above the social tariff for the previous period (quarter) or 20% above the average tariff for the previous four periods (ie one year).¹¹

- **Cyprus** has both a block tariff and additional social tariff approach with the former available to all customers and the latter only to designated vulnerable customers. The social tariff applies a 20% discount to each block tariff level, subsidised by a Public Service Obligation levied on all other customers. The criteria for eligible vulnerable customers are relatively narrow and have historically encompassed less than 5% of residential customers.

Tying criteria to existing welfare schemes should reduce the administrative burden and may enable the automatic enrolment of eligible households into the scheme. In GB this includes those who receive one of a set of means-tested benefits and tax credits. In order to further improve targeting on the fuel poor, GB also considers property characteristics (floor area, property age, property type). This will either be taken directly from national databases or imputed from neighbouring properties, Energy Performance Certificates, and other statistical information. This approach helps targeting at energy poverty in particular but does add considerable complexity to the process.¹²

If taking property characteristics into consideration, an alternative approach will be to stagger the size of the lump sum payment based on a set of different household typologies such that the payment is calculated to meet a set portion of expected space heating requirements. This would, however, only be relevant for the minority of households with electric heating.

In designing a social tariff, consumer consent is crucial and therefore we recommend prioritising:

- **Simplicity:** Both the GB and Cyprus schemes above are relatively simple. Belgium's is more complex and, while giving additional protection in the event of volatile prices, likely poorly suited to a small area with a single supplier. The advantage of a lump sum payment (as in GB) in comparison to a percentage reduction (as in Cyprus) is that the subsidy will not increase in line with additional discretionary energy use. Conversely, by not scaling with energy use it is decoupled from the household characteristics (beyond the initial eligibility check).
- **Appropriate targeting:** Tying the scheme to appropriate current welfare system that map suitably to energy poor households will reduce the administrative burden and free riders as well as potentially enable auto-enrolment. Further consideration of property characteristics as in the GB WHD scheme may however be considered an overly onerous administrative burden.

We also recommend any such policy is considered in coordination with Manx Gas given space heating is typically the primary consideration for social tariffs in the energy sector.

¹¹ CREG. 2021. [Study on the increase in electricity and gas prices in Belgium](#)

¹² Ofgem. 2022. [Warm Homes Discount Guidance for Suppliers](#)

3.2.4 Recommendations

Taking the above discussion into consideration, we recommend:

- Categorising consumers by voltage level would be consistent with peer jurisdictions and broadly cost reflective. However, the current tariff categories largely enable this while retaining familiar terminology for users, therefore for reasons of stability **no change is recommended**.
- Due to the smart meter rollout categories are increasingly justified solely by **customer consent** (simplicity, ability to respond) rather than technical ability to measure (ie metering equipment). This **supports the continued separation of certain tariff options for domestic and smaller commercial customers**.
- The relative benefits of financial transfers and social tariffs are a policy decision for the Isle of Man government. However, should a social tariff be deemed desirable **we recommend that it is structured simply** (eg lump sum payment to qualifying households or percentage reduction in tariff – unit rate and/or standing charge - up to a cap) and draws on the **existing welfare system to target support**. We also recommend it is developed in **coordination with Manx Gas**.

3.3 Types of charges

In order to be cost reflective, tariffs can be structured through a combination of charges that scale with different drivers. The core building block options are described in Table 5 below.

Table 5 Definitions for types of charges

Charge	Sample unit	Definition
Demand charges	Amount per metered maximum KW or KVA in a specified period	<i>A charge paid by customers for use of network capacity. It is based on the metered maximum demand in a given time period (eg kW or kVA per period). It may or may not differentiate by TOU.</i>
Contracted capacity charges	Amount per contracted KW or KVA in a specified period	<i>A charge paid by customers for contracted capacity or supply capacity per kW or kVA per period. It may or may not differentiate by TOU (eg it may be more expensive in some seasons).</i>
Fixed (standing) charges	Amount per day, month, or year	<i>A constant sum paid by the customer at predetermined time intervals (eg per day, month, or year), irrespective of the customer's demand, system peak or other characteristics.</i>
Energy (volumetric) charges	Amount per kWh consumed	<i>A charge paid by the customer for each unit of energy consumed (eg per kWh, per MWh, etc). It may or may not differentiate by TOU.</i>
Reactive power charges	Amount per KVAh consumed	<i>A charge expressed in £/kVAh for reactive power</i>

Note: The above charges can vary by season and/or TOU. If the charge does not vary according to TOU the charge is referred to as flat.

Economic theory suggests that tariff structures should reflect economic costs. This implies that an ideal rate structure will comprise the following elements:

- **Time-varying energy (kWh) charges** should be used to recover the variable costs of electricity supply in each interval reflecting the variable costs of the system at each interval.
- The fixed costs of network capacity should be recovered through **charges based on demand (kW or KVA) or contracted capacity**, as this is the driver of investment needs.
- **Fixed or customer charges (per customer)** often called standing charges should be used to recover the costs of customer-related activities such as metering, billing and collections which do not vary with customer demand or consumption and usually vary in relation to the number of customers.
- **Reactive power charges (kVArh)** should be used to provide incentives for customers to improve their power factor and, therefore, reduce the costs of supplying them.

As described above, in practice rates will often deviate from this ideal structure for many reasons, including issues of acceptability, affordability, simplicity, equity and cost of metering relative to the benefits achieved from more complex rate structures and other policy objectives.

The following sections discuss each of the charging types in turn and their appropriateness for application in the Isle of Man for each customer category (domestic, commercial and industrial).

3.4 Reflecting demand/capacity-driven costs

3.4.1 Purpose of demand and contracted capacity charges

Demand or capacity charges are intended to reflect costs that are driven by the maximum demand of consumers and/or their contracted level of supply capacity. This is focused on network costs as lines are sized to meet peak requirements.

There are three general forms a maximum demand / contracted capacity charge takes:

- Scaled to demand at time coincident with system peak demand in a given period.
- Consumers' own maximum demand in a given period.
- Consumers' contracted capacity limit (with either some form of governor to prevent exceedance or a penalty rate applied).

Which form (or combination of forms) is most cost reflective will depend on the point of network of interest. At transmission and higher voltage distribution level, costs are driven by the coincident maximum demand. For local networks supplying individual customers or smallish groups of customers, network charges based on contracted capacity are most cost

reflective. Networks are designed to be able to meet the current and future capacity requirements and the contracted capacity is a good proxy of the capacity costs each customer imposes to the system.

The Isle of Man currently imposes Maximum Demand and ASC charges (the latter a form of contracted capacity charge) to all industrial customers with a peak demand in excess of 50 kVA.

Cost reflective Maximum Demand and ASC charges would recover the economic fixed costs of network capacity. In theory, they could also look to recover fixed costs of generation capacity to the extent MU face these directly (as opposed to being integrated into wholesale energy prices paid for in volumetric terms by MU themselves). However, as wholesale trading across the interconnector is priced in volumetric terms, it is recommended to focus on network costs only.

Network costs are typically recovered through one of two primary methods:

- **Long-run marginal cost (LRMC):** Attempts to mimic the price that should emerge in a competitive market. It estimates the LRMC for providing power and energy to each consumer group and designs tariffs that reflect marginal costs of supply. The long-run average incremental cost (LRAIC) approach also falls into this category - it attempts to estimate the incremental costs for serving an additional unit of capacity and is the methodology typically applied for transmission and distribution networks when using forward-looking or economic costs for tariff design purposes. As historic costs still need to be recovered, the calculated LRMC values may be scaled or otherwise adjusted to ensure full cost recovery.
- **Embedded cost:** This approach is based on historical, accounting (hence embedded) expenses, and is, therefore more direct compared to the LRMC method. Using this approach actual accounting expenses are calculated and allocated to customer categories. The key difference with the LRMC approach is that embedded cost is backward looking whereas LRMC is forward-looking.

While the LRMC approach is the more cost reflective approach, it has limited relevance in a system with substantial spare capacity and no locational pricing. The marginal cost at many nodes in such a system will be zero as there remains headroom for demand to grow into. The Isle of Man has seen declining demand for more than the last decade while its Future Energy Scenarios¹³ foresees this decline to continue through to 2026 after which electrification of transport and heat will instigate renewed growth. Total demand is only forecast to exceed historic volumes beyond 2030, outside the timeframe of the Pricing Strategy Review, and is contingent upon the foreseen trends being realised. Current network costs are therefore almost exclusively historic (often termed “residual”) and will likely remain so for a substantial period to come.

Therefore, as for the previous review, network costs can be considered driven by the need for refurbishment and end-of-life replacement rather than new demand. Undertaking a marginal cost assessment in this context would be onerous and likely largely superfluous given, with discounting, the load related differences in future asset replacement costs are likely to be relatively low compared with a situation where load is growing. As a result, taking the embedded cost approach, reflecting historical costs, is reasonable.

¹³ Isle of Man Government. 2022. [Isle of Man Future Energy Scenarios](#)

There is no cost reflectivity argument for any particular mechanism for recovering such residual costs as they are not forward-looking, other than to avoid undue distortion to other cost reflective charges. Ramsey pricing¹⁴ would recommend allocating to the least elastic demand sources, however as these may be domestic consumers (in particular lower income ones) this approach would run against the principles of customer consent and social policy.

Applying in some form in relation to network usage is therefore advisable, however this could be volumetric, demand, or contracted capacity in nature.

Considering the above, we discuss the role for Maximum Demand and ASC charges for each customer category in Isle of Man in turn, with a separate discussion for private generation, before providing general recommendations.

Industrial consumers

Except for entities with private generation, uniform **Maximum Demand** and **ASC** charges are currently applied for all industrial consumer tariffs in the Isle of Man with a maximum load exceeding 50 kVA as per Table 4.

The Maximum Demand charge is applied for the consumers' *individual peak* rather than *system coincident peak*. As discussed above, in an LRMC framework the more cost reflective approach depends on the network configuration and point of congestion but generally for larger consumers connected at high voltage levels, coincident peak would be preferable.

A second question concerns whether there is any benefit to having both Maximum Demand and ASC charges. Contracted capacity charges can assist in system planning and give greater revenue certainty to the utility, although there will be some moderate inefficiencies due to consumers' need to maintain a degree of headroom above their projected maximum demand to avoid incurring penalties.

Given the largely overlapping intent of the charges and the above discussion regarding the historic nature of network costs, **it is recommended for simplicity to aggregate into a single ASC without a differentiated Maximum Demand charge**. This will mean a cost that scales in proportion to peak demand (providing a benefit to entities with a higher load factor). It also means that should network expansion to manage increasing demand become a more prominent feature of future pricing strategy reviews, the tariff design contains an appropriate structure for implementing forward-looking network price signals.

Commercial consumers

For commercial consumers there is a separate question as to whether a similar charge should be extended to those with a lower maximum demand. Commercial entities are likely to be in a similar position to domestic consumers with limited knowledge and ability to respond to

¹⁴ Ramsey pricing is an economic concept that seeks to maximise economic efficiency when a monopoly service provider is required to allocate the difference between the average costs they face (which include historic, or residual, costs) and revenue from marginal pricing, across different customer groups. It states that prices should be set such that the demand for all customer groups falls by the same proportion. This means levying the highest mark-up on those with least elastic demand (ie least price sensitive customers). In the context of electricity this may be low income residential households meeting basic needs and hence the application of Ramsey pricing can have unwanted distributional impacts.

complex tariff formations. Given the lack of immediate benefit from LRMC forward-looking pricing, the case for imposing such a charge is limited. The current approach of effectively recovering the cost through an uplift to unit prices (in kWh terms) is therefore deemed acceptable except for those with private generation addressed below.

Nevertheless, a subset of this group may be interested in greater engagement with their energy use, for example those who have installed an EV or home energy battery system. We therefore **do not recommend a mandatory ASC for lower demand consumers** but suggest MU consider wrapping such a charge together with a form of TOU energy pricing as an **opt-in tariff product**. This is discussed further in Section 3.6.

Domestic consumers

As noted in Section 3.2, maximum demand charges are often avoided for smaller consumers (particularly domestic) for reasons of simplicity and ability to respond (and historically, due to metering constraints). Contracted capacity charges help mitigate some of these concerns by enabling customers to set their maximum in advance, possibly supported by technical controls such as a fuse tripping when capacity is exceeded as has been the case in Spain. However, implementation can still be contentious.

Given the limited need for economic price signals in networks due to falling demand, it is **not recommend to implement a mandatory ASC on domestic consumers**. Rather, similar to small commercial consumers, an **opt-in tariff product** may be developed with such additional complexity for those desiring deeper engagement with their electricity use, as discussed in Section 3.6.

Private generation

The absence of cost reflective demand or capacity charges can be particularly problematic in the presence of increased behind-the-meter private generation. Self consumption displaces retail market purchases. Where fixed costs are recovered through volumetric charges and the volume of sales is reduced (but the fixed costs incurred by the utility are not) this creates a revenue shortfall which is either borne by the utility or recovered from non-participating consumers. Such a result can be considered an effective cross-subsidy which may be regressive in nature if participating consumers are more likely to be higher income households. This problem becomes more acute the higher the share of private generation and could create a disincentive for MU to support uptake of rooftop solar PV.

MU already impose a higher demand charge (termed a “**Reserve Demand Charge**”) on industrial consumers with Combined Heat and Power (CHP) units (those on a private generation tariff) at a rate of £4.29/kVA as opposed to the standard £2.76/kVA. This reflects that the standard Maximum Demand charge, even in combination with the ASC, is not sufficient to cover associated fixed costs.

Options for addressing the similar concern for domestic and commercial consumers availing the Sustainable Generation tariff include:

1. Ensuring all consumers face a cost reflective Maximum Demand and/or ASC charge.

2. Uplifting the Standing Charge for all consumers to recover part of all associated fixed costs.
3. Implementing a designated Maximum Demand and/or ASC only for those consumers availing the Sustainable Generation tariff.
4. Uplifting the Standard Charge only for those consumers availing the Sustainable Generation tariff.

Option 1 is the most cost reflective and would guard against any further distortions in price signals and incentives to consumers from occurring. However, for reasons previously noted there is concern that the complexity and unfamiliarity with the approach may hinder customer consent.

Option 2 uses the existing tariff structure for domestic and smaller commercial consumers but would still require a large uplift to standard charges across all affected customers. While fixed and therefore unable to be avoided through behind-the-meter generation, standing charges don't reflect differences in the maximum demand or capacity of connections between customers.

Option 3 creates a cost reflective tariff for private generation without impacting on the tariff structure of other consumers. Those availing the Sustainable Generation tariff are more likely to be engaged in their energy use and able to understand novel charging arrangements. An ASC is considered more suitable than a Maximum Demand Charge for the same reasons as provided above for industrial consumers.

Option 4 is a simplified but less cost reflective variation on Option 3.

We recommend that Option 3 be considered as the best compromise between the conflicting principles of economic efficiency / cost reflectivity and consumer consent / simplicity. For simplicity and to avoid too dramatic a change to current prices, it is recommended the unit price remains either the standard domestic or two-part TOU domestic rate. This means some fixed costs will still be recovered through the volumetric portion the tariff, which in turn limits the size of the ASC needed to avoid a revenue shortfall for MU.¹⁵ Should environmental policy support the subsidising of sustainable private generation then this is considered best done via either the export tariff (see Section 3.6) or financing/grant support for capital outlay.

3.4.2 Setting demand and contracted capacity charges

MU is both vertically and horizontally integrated in that it undertakes generation, distribution and retail for electricity, as well as water and wastewater services. Cost data provided to ECA indicates £11.16 million (nominal terms) in net costs for the financial year 2023/24 are attributable to Network Power Systems and Network Wayleaves. The interconnector is currently overwhelmingly used for the export of power and therefore associated costs may be considered attributable for tariff design purposes to generation/trading. Smart metering costs

¹⁵ A 2-3 kW household system will typically meet around 40% of residential electricity demand and if the unit price remains the same as for standard domestic customers, then the ASC need only be sized to cover this share of the related network fixed costs.

of £1.16 million are also not included in this figure as these are largely customer, rather than demand/capacity, driven.

Divided by island annual sales of 338,761 MWh equates to 3.29 p/kWh per unit sold. If differentiated between HV (11 kV) and 11 LV (0.4 kV) customers then we estimate the equivalent costs would be 2.22 p/kWh and 3.56 p/kWh respectively. At an assumed grid load factor of 65% and power factor of 0.9, this is equivalent to a capacity charge at peak of £14.07/kVA/month. If differentiated between HV (11 kV) and 11 LV (0.4 kV) customers then we estimate the equivalent charges would be £9.06/kVA/month and £15.72/kVA/month respectively.

Adopting the above levels would represent a major change for Isle of Man consumers with demand exceeding 50 kVA given the low current rates (an increase of almost four times the Maximum Demand and ASC combined). This may prove difficult to implement in a single step and rather a transitional period could be considered. The equivalent rates in Jersey and Guernsey are shown in Table 6 below. Adjusted to monthly equivalents, the rates for Guernsey and Jersey sit between the current low rates in Isle of Man and the cost reflective capacity charges estimated above. Setting a similar level in Isle of Man with the remaining portion being recovered through volumetric charges may prove a suitable compromise for the forthcoming five-year pricing strategy period.

Table 6 Maximum demand charges applied in Guernsey and Jersey

Tariff product	Demand charge applied
Guernsey Industrial Maximum Demand tariff	£18.60/kW/month (November to March only)
Jersey Maximum Demand Tariff Low Voltage (0.4 kV)	£11.58/kVA/month (November to April) £8.84/kVA/month (May to October)
Jersey Maximum Demand Tariff High Voltage (11 kV)	£10.89/kVA/month (November to April) £8.17/kVA/month (May to October)

Sources: Guernsey Electricity. 2024. [Tariffs from 1st July 2024](#); Jersey Electricity. 2024. [Tariffs - Maximum Demand](#)

3.4.3 Recommendations for demand-driven costs

Our summary recommendations for reflecting demand-driven costs are:

- ***For all tariffs breaching the 50 kVA threshold (industrial and commercial):***

To aggregate into a single ASC without a differentiated Maximum Demand charge. We note that this is a similar amendment to that recently undertaken by Ofgem through its Targeted Charging Review to revise the GB approach for recovering residual network costs.¹⁶ Given the lack of a meaningful forward-looking component to MU's network costs we consider the ASC alone to be sufficient. If set to recover all fixed network costs, this new ASC is estimated to be £14.09/kVA/month. Due to the potential difficulties with consumer consent in adopting such a large change from current levels as a single step, a lower value benchmarked to Guernsey and Jersey of £9.17/kVA/month (representing 50% of

¹⁶ Ofgem. 2022. [CMP343 Decision and final impact assessment](#)

the full uplift) could be considered with the remaining costs continuing to be recovered through volumetric charges.

- ***For all standard¹⁷ tariffs not breaching the 50 kVA threshold:***

For reasons of simplicity and consumer consent we do not recommend a mandatory ASC for lower demand consumers on standard tariffs. Costs would continue to be recovered through a volumetric equivalent priced in per kWh terms. This recommendation extends to the proposed three-part TOU tariff option as, upon completion of the smart meter rollout, this is expected to replace the existing Comfy Heat tariff and may therefore be considered familiar to current customers. In the case of the three-part TOU tariff, we propose weighting the fixed costs towards the peak periods for consistency with environmental policy in ensuring TOU differentials are sufficiently pronounced and also for easier future transition into any marginal cost pricing approach should network expansion be required.

- ***For non-standard tariff¹⁸ options to all consumers:***

To apply an ASC alongside any complex TOU pricing and/or export tariffs for private generation. Such consumers are already seeking additional complexity in their tariff design, reflecting higher engagement with their energy use. It is therefore considered more reasonable to include an opt-in tariff offer for all LV customers that seek to avail smart meter capabilities. As discussed in Section 3.6 below, this may include a “fully cost reflective” tariff option including a designated ASC (at £14.07/kVA/month) and granular TOU pricing (discussed in Section 3.6 below). As all network costs are recovered through the ASC, the volumetric rate for such an option would be commensurately lower.

In the case of private generation, the ASC could be mandatory but would be at a lower rate if paired with either the flat or standard TOU tariff options as in these cases a portion of the fixed costs would remain recovered. Assuming a typical 3 KW rooftop system covering around 40% of household demand, the ASC would be £6.29/kVA/month.

3.5 Reflecting customer-driven costs

3.5.1 Purpose of standing charges

Fixed or customer charges (per customer) should be used to recover the costs of customer-related activities such as metering, billing, collections and customer services (customer application, call centres, complaint handling) which do not vary with customer demand or consumption but rather in relation to the number of customers. In the Isle of Man these take the form of **standing charges**.

Cost data provided to ECA allocates corporate costs of £7.12 million to electricity for the financial year 2023/24. This includes but is not limited to customer service costs (driven by

¹⁷ See following discussion on complex TOU tariff options including the potential for an hourly or half-hourly price that varies in relation to GB wholesale prices.

¹⁸ Including sustainable generation tariffs

customer numbers) although all may be considered fixed costs for tariff design purposes. A further £1.16 million is attributed to the Smart Metering Programme which could be considered to scale predominantly by number of customers.

In 2023/24, MU had 50,656 electricity customers of which only 326 were on tariff rates with the higher standing charge of 42.9p/day with the remainder (bar 47 Public Lighting customers) on the standard rate of 24.5p/day. This yields an estimated income of £4.6 million per year out of total energy sales revenues of £69 million forecast for 2022/23 and a required revenue in the coming five-year period averaging over £95 million per annum.

Recovering the sum of corporate costs and the smart meter programme through the standing charge would require a rate of 44.8p/day, around 80% higher than the current level. Raising such charges can be controversial, in particular due to the perceived impact on low income households. The previous Pricing Strategy Review argued against replacing standing charges with a system of rising block tariffs due to the latter being poorly targeted and non-cost reflective. The same recommendation is retained in this report. To help guide an appropriate level for MU to set standing charges in the Isle of Man, the following sub-section discusses how this issue has been addressed in nearby jurisdictions and compares it to the above estimation.

It is noted that the debate in some cases (such as that for Guernsey below) implies or states that for consumers with no demand or capacity charge, the standing charge is a more cost reflective mechanism for recovery of fixed network costs than unit rates. This may be the case under a scenario of network expansion and with adequate banding of customer categories such that the distortion (caused by different connection capacities and peak demand not being reflected in different standing charges) can be suitably minimised. But this is not the situation in the Isle of Man and a similar approach can anyhow be applied to volumetric pricing.

Standing charges do help protect against the reduced fixed cost contributions from private generation and also avoid unduly penalising heat pump and EV owners who may as a result make a disproportionate contribution to fixed cost recovery under volumetric pricing given their higher demand. However, private generation can be managed through a special tariff category, while the option of an innovative more granular TOU tariff with a separate ASC (see Section 3.6) could appeal to heat pump and EV early adopters.

As discussed above cost reflectivity is focused on forward-looking marginal costs for network expansion rather than recovery of historic (residual) costs. Given current standing charges are insufficient to recover only those costs associated with customer-related and other general corporate activities, it is likely undesirable and **not recommended for reasons of consumer consent to seek to recover demand-related costs (ie fixed network costs) through the standing charge also.**

3.5.2 Benchmarking of standing charges

Great Britain

In Great Britain Ofgem recently ran a call for inputs on standing charges and potential alternatives in November 2023.¹⁹ In this, some responses from civil society organisations argued for abolishing standing charges in favour of rising block tariffs on the grounds that:

¹⁹ Ofgem. 2023. [Standing charges – call for input](#)

- Standing charges have a disproportionate impact on lower income households and those who consume less energy.
- This risks the wellbeing of vulnerable households and reduces the incentive to save energy.

However, Ofgem analysis shows that removing the standing charge could hurt 1.2 million low income households by a considerable amount more per household than the larger number of low income homes that would benefit. The negatively impacted homes are predominantly those with electric heating. The consensus among suppliers with the support of some consumer groups was that removing standing charges is not a solution to address affordability concerns. They instead advocated a targeted social tariff or rebate on energy bills for eligible customers. The benefits of different tariff options with various standing charges / unit rate splits were also highlighted.

Northern Ireland

Standing charges were effectively removed from Northern Ireland's domestic electricity tariffs in 1999 with the aim of protecting vulnerable consumers. This meant that while the distribution network owner, NIE Networks, charged suppliers use of system charges that included a fixed component, when passing through to customers suppliers "smoothed out" these charges as unit-based fees.

The Utility Regulator (UR) for Northern Ireland was conscious that such smoothing had some distortive effects on end use retail prices with larger domestic users making a bigger contribution to suppliers covering fixed costs. As a result, those suppliers were at a competitive advantage when marketing to smaller customers as compared to smaller entities without a significant large consumer customer base from which to cross-subsidise in this manner.

In 2017, UR reviewed distribution network use of system charges calling stakeholder views for two options to avoid distortions:²⁰

- Option 1 – Retain current fixed charge component in use of system charging and allow suppliers to reintroduce standing charge in retail tariffs.
- Option 2 – Introduce per unit domestic use of system charges and remove current standing charges element.

UR concluded that with the energy transition a higher portion of total costs are likely to be fixed and therefore the less distortive and disruptive approach would be to retain the cost reflectivity of standing charges with an understanding they may need to rise in the future.²¹

Guernsey

In 2022, the States' Trading Supervisory Board received an application from Guernsey Electricity Ltd (GEL) to increase electricity tariffs. GEL had concerns that their cost base split

²⁰ Utility Regulator. 2017. [Review of DUoS Domestic Tariff Charging Methodology – Consultation Paper](#).

²¹ Utility Regulator. 2018. [Review of DUoS Domestic Tariff Methodology - Decision Paper](#).

(approximately 50:50 fixed versus variable) was not reflected in the current tariff structure, where 10% of its revenues were generated through fixed charges and 90% through its variable charge.²²

The Board acknowledged the need to restructure GEL's tariff to ensure the standing charges better reflect its fixed costs, while addressing the impact on vulnerable customers through social policy interventions. The resulting amendment to the tariff rate from the review is shown in Table 7. While these tariffs increase the fixed cost portion, we note that they are likely to remain far below the 50% attributable to fixed costs. However, for the reasons given through Section 3.4, standing charges are cost reflective of customer-driven costs but not necessarily all fixed costs.

Table 7 Standing charge amendments to GEL standard domestic tariff July 2022

	Prior to change	Revised tariffs
Standing charge (primary meter)	£17.97 per quarter	£30.00 per quarter
Standing charge (secondary meter)	£3.01 per quarter	£5.02 per quarter
All units	19.78p/kWh	20.77p/kWh

Source: GEL

Comparison on rates

A general comparison of standing charges in the Isle of Man to those in place in a set of other relevant jurisdictions is shown in Table 8 below for standard domestic customers. As can be seen, the rates in Isle of Man are noticeably lower than GB and Guernsey although comparable to Jersey and higher than in Northern Ireland. An uplift to the 44.8p/day estimated above as being sufficient to recover customer-related activities and other corporate costs allocated to electricity remains 25% below the GB level. It is noted that while industrial customers pay a standing charge 1.74 times that of domestic and smaller commercial customers, due to their far lower number this has very little impact on the average rate to be recovered.

Table 8 Standing charges for domestic consumers in a selection of jurisdictions

Jurisdiction	Standing charge (p/day)
Isle of Man	24.6
Guernsey	74.79 (primary meter only)
Jersey	21.97 (single phase) / 48.05 (three-phase)
GB (Ofgem price cap)	60.10 (average GB)
Power NI	13.34 - 13.68 (only applied to non-standard tariff options)

Source: GEL, JEL, Ofgem, Power NI

3.5.3 Recommendations on standing charges

Our summary recommendations for reflecting customer-driven costs are:

²² Guernsey Electricity. 2021. [Interim arrangements for tariff regulation](#).

- **Standing charges should be retained** as the preferable means to recover costs associated with customer-related activities (billing, metering, collections and customer liaison etc).
- Concerns regarding vulnerable consumers are most appropriately managed through targeted rebates or a **social tariff for eligible recipients** rather than a block tariff structure that creates wider distortions.
- The **current level of standing charges** on Isle of Man is, however, **low and likely insufficient** to recover all potentially attributable costs. A comparison with neighbouring jurisdictions indicates there is some headroom to raise these and as such an increase is recommended.
- For consumers without demand or capacity charges, related costs (predominantly **fixed network costs**) are recommended to **remain recovered through volumetric charges** as the case for recovering through standing charges is qualified and would represent a very sizeable shift inconsistent with the principles of **consumer consent and stability**.
- For **private generation**, a **special tariff category with an ASC** for recovering fixed network costs in addition to unit rates and a standing charge is proposed as per Section 3.4 for domestic and small commercial customers. However, if this is not considered feasible, a higher standing charge specific to this customer group may be considered to ensure fixed cost recovery.

3.6 Reflecting volume-driven costs

Volume-driven costs refer to costs that need to be recovered which vary on a per kWh basis. Traditionally, utilities had relatively steady fuel costs, so flat volumetric tariffs using time-agnostic meters may have been seen as sufficiently cost reflective. However, the advent of Advanced Metering Infrastructure²³ (AMI) brings opportunities to better align the hourly price of electricity with the cost of supply via more granular TOU tariffs²⁴. Growing zero marginal cost renewable energy system (RES) generation can also be expected to increase the volatility of hourly supply costs.

TOU tariffs enabled by AMI should improve economic efficiency over standard flat rate tariffs by directly incentivising consumers to shift their load to lower cost time periods, which would reduce system-wide energy / fuel and network costs. Time-based and / or critical peak pricing are not new for larger industrial consumers, but the spread of AMI is increasingly bringing

²³ We understand from the first workshop with Manx Utilities that the smart meter rollout programme is expected to be completed in 2-3 years time.

²⁴ Other potential AMI benefits include reduced billing and meter reading costs, the longer-term potential of 'smart/intelligent grid' developments, such as TOU appliances, and the change partly being enforced by manufacturers ceasing to produce old-style 'dumb' meters.

A 2018 Manx Utilities Board paper, which compared an Island-wide electricity AMI rollout to a business-as-usual (BAU) case where MU implemented a new advanced prepayment system and gradually replaced the existing meter fleet with smart meters that lacked advanced functionality, which found a positive annualised NPV for an Island-wide AMI rollout, which held under multiple sensitivities.

TOU tariff options to domestic customers. TOU tariffs should improve economic efficiency and lower overall system costs but its growing rollout also brings some risks.

3.6.1 Wholesale electricity costs

Hourly economic value of electricity for the Isle of Man

In terms of economic efficiency, the ideal is to match the hourly price of electricity that consumers face with the hourly cost of supply. This requires an idea of the hourly economic cost of supply on the Isle of Man. In larger, competitive markets, this measure can be determined by the outcome of hourly spot markets²⁵, but no such market exists on the Isle of Man.

However, while the Isle of Man is virtually self-sufficient in electricity generation, it does trade electricity with mainland GB via an interconnector with sufficient capacity (60 MW) such that there are few constraints on trade given the Isle of Man's peak demand of ~80 MW.²⁶ The hourly economic cost can therefore be represented by the wholesale electricity price on mainland GB²⁷, which, in economics jargon, represents the opportunity cost of wholesale electricity supply in the Isle of Man.

- If the interconnector is **exporting** (which is most of the time²⁸), the opportunity cost of a kWh sold to a customer on the Isle of Man is the foregone revenue of selling a kWh to mainland GB (including losses).
- If the interconnector is **importing** (which tends to be in the early morning when load is growing but it is not yet cost-effective to bring the second gas turbine into operation or late evening when load is dropping), a kWh sold to a customer on the Isle of Man is a kWh that must be imported from mainland GB.

In both cases, the mainland GB wholesale market should reflect the benchmark for the economic cost of wholesale electricity supply for MU.

An exception to the above is if the interconnector is already importing at full capacity, but this would likely be an exceptional circumstance where on-island generators are experiencing

²⁵ A modelled approach would be an alternative, either doing a bottom-up cost modelling exercise of the assumed marginal generator or running a power simulation model, but these can be arduous, data- and computation-heavy exercises.

²⁶ The importance of the GB market linkage will be strengthened even further if Manx Utilities proposals for a second interconnector go ahead.

²⁷ Plus interconnector fees. Losses also need to be accounted for, particularly at peak given technical losses are higher during times of peak demand. This is purely for technical reasons - copper losses increase with the square of the current (losses = I^2R , where I is the current (Amps) and R (ohms) the resistance and the losses are in Watts). The relationship between average losses and peak losses is often based on a standard equation where peak losses are average losses (%) divided by $(0.3 + 0.7 \times \text{Load Factor})$, so that the higher the load factor the closer are the peak losses to the average losses.

²⁸ Manx Utilities' [Annual Report 2022/2023](#) reports that 37% of Manx Utilities' local generation was exported to the UK in 2022-23.

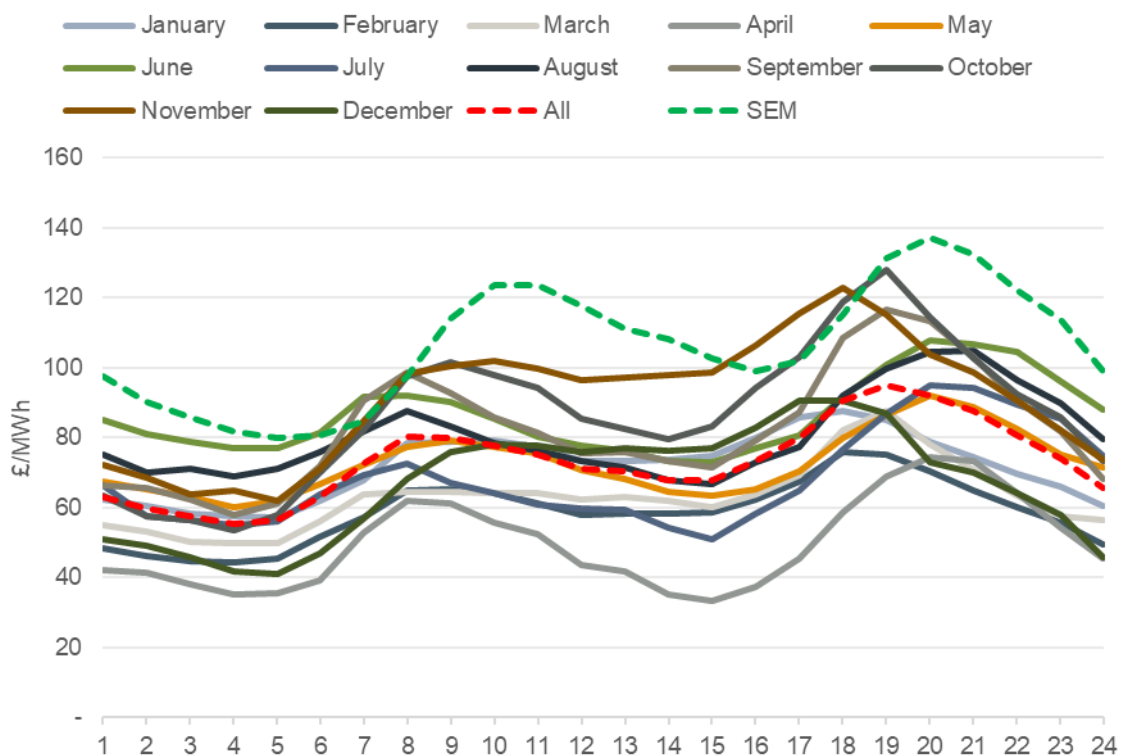
outages. Likewise for rare periods where the interconnector is unavailable the economic cost would default to the marginal cost of on-island generation.²⁹

GB market as benchmark for hourly economic value of electricity

Time-of-day wholesale costs in GB

We report average hourly electricity wholesale prices for GB in Figure 2, which should reflect the most relevant benchmark for the hourly cost of electricity supply in the Isle of Man.

Figure 2 Average hourly electricity wholesale price for GB (by month) and Single Electricity Market (SEM), June 2023 – May 2024



Source: Elexon BSC, [Market index prices](#), APX; SEMOpX [Monthly Market Report May 2024](#). GB figures represent the average of half-hourly APX prices for each hour.

Focusing on the all-year result in **dashed red**, there are clear morning and evening peaks. The evening peak ranges from 16:00-22:00 with an average price of £88/MWh. A nighttime low can be seen from 1:00-5:00 with an average price of £57/MWh, while the remaining 14 hours have an average price of £71/MWh. The morning peak is not sufficiently differentiated to justify a separate pricing band.³⁰

²⁹ Manx Utilities' [Annual Report 2022/2023](#) reports that the interconnector had an availability of 99.4% in 2022-23.

³⁰ This conclusion is purely looking at volumetric costs. As demonstrated by Octopus' Agile tariff, recovering network and capacity costs at peak via per kWh charges may lead to a higher peak, but such costs are less relevant to the Isle of Man.

Figure 2 also reports average prices from the Ireland-Northern Ireland SEM Day-Ahead Market (DAM) as another potential comparator. The hour-to-hour results are more variable, which may explain why some suppliers are offering three-part tariffs in Ireland (Table 9). DAM prices in the SEM are notably more elevated than GB's, likely reflecting the combination of an ongoing supply crunch in Ireland³¹, the SEM's higher reliance on gas, and less diversified gas supply.

While many forecasts expect greater price 'peakiness' as RES penetration increases, with price variations due to solar-driven 'duck curves' or wind variations, this is not particularly apparent in the latest GB price curves. However, this is worth monitoring as the gas price crisis of 2021-22 recedes, RES integration continues to increase, and low-carbon technologies (LCTs) such as EVs, heat pumps, and rooftop solar begin to impact hourly demand. One potential countervailing factor is the deployment of grid-scale battery energy storage systems (BESS) seeking to take advantage of any arbitrage opportunities, which may 'cannibalise' price differentials.³²

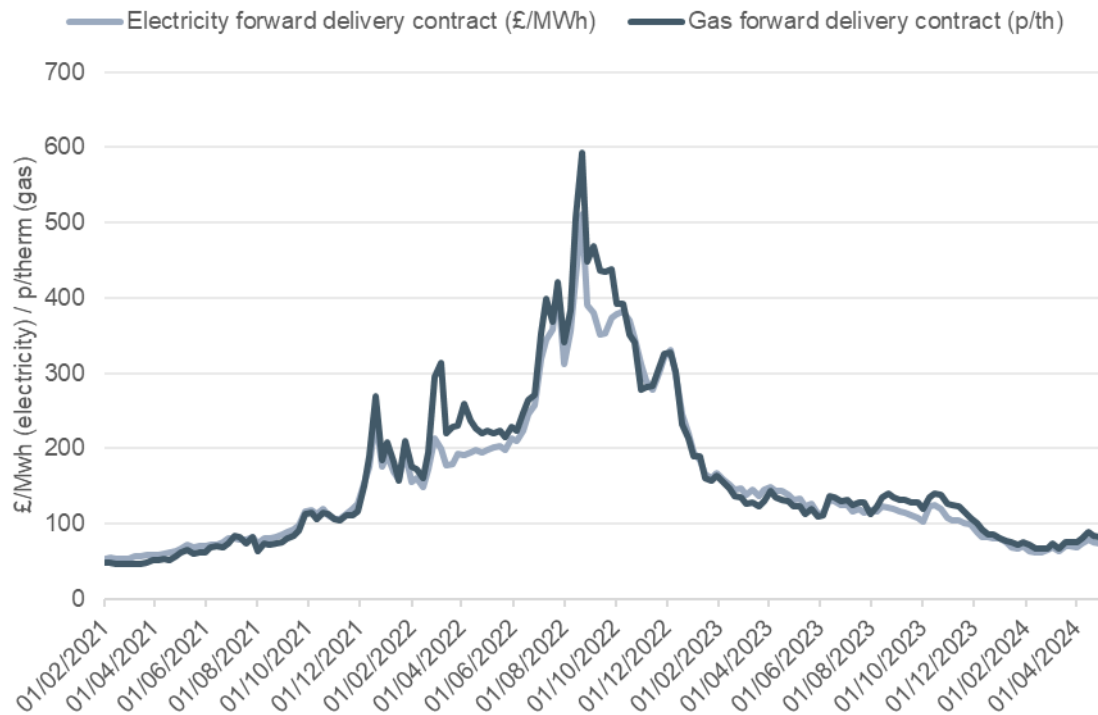
Seasonality

While some seasonality is usually a characteristic of the GB electricity market³³, it is not immediately apparent from the previous year of hourly prices in Figure 2. This likely reflects gas price trends, which were still relatively elevated in the summer and autumn of 2023 compared to winter 2024 (Figure 3).

³¹ N. Sargent, 20 December 2022, [‘Heads must roll’: Industry and experts argue energy crisis of ‘our own making’](#), *The Journal*.

³² In California, where the solar 'duck curve' effect has been most prominent, there is evidence that this effect has started to reverse now that CAISO has over 5 GW of grid-scale BESS capacity: Grid Status, 7 May 2024, [Batteries Taking Charge of the California Grid](#).

³³ Figures 12 and 13 of ECA's previous Pricing Strategy Review for Manx Utilities reviewed hourly market prices for GB in 2017 and observed evening prices spiking to ~£70-90/MWh in the months of January-March and October-December. In contrast, the evening peak was only ~£50-65/MWh for the spring and summer months.

Figure 3 GB electricity and gas wholesale market indicators, Ofgem

Source: Ofgem, [Wholesale market indicators](#), accessed 7 June 2024.

Weekday versus weekend effects

There are rare cases of jurisdictions offering lower rates on weekends (Section 3.6.2), when demand is generally lower. In GB, we observe modestly higher prices in the afternoon-early evening on weekdays (Figure 4), but not material enough to suggest separate weekday and weekend tariff rates are justified. Across the day, weekday prices are only 2.5% higher on average.

Figure 4 Average hourly electricity wholesale price for GB, weekday versus weekend, June 2023 – May 2024



Source: Elexon BSC. Each hour reflects half-hourly average.

3.6.2 Comparator jurisdictions

Alderney, Cyprus, Guernsey, Ireland, Jersey, Malta, Northern Ireland

We first provide a review of the TOU tariffs on offer in a set of comparator jurisdictions in Table 9 (nearby and island-based systems): Alderney, Cyprus, Guernsey, Ireland, Jersey, Malta, and Northern Ireland, and compare to the current TOU rates offered by MU. For each tariff, we report the number of TOU periods, the number of off-peak hours, and the ratio of peak price to off-peak price. The data in Table 3 helps inform our TOU design considerations in Section 3.6.3.

Table 9 Examples of TOU and peak/off-peak price ratios in other jurisdictions

Jurisdiction Tariff	Periods per day	# off-peak hours	Peak-off-peak price ratio	Notes
Isle of Man				
Comfy Heat	3		1.71	Off-peak: 0:00-6:00 and 14:00-16:00 Peak: 6:00-14:00 and 16:00-0:00
Commercial Plus				
Economy 8 Commercial		8	1.58	
Economy 8 Demand	2		1.43	Off-peak: 23:00-7:00 Peak: 7:00-23:00
High Volume 2 rate			1.36	
EVs		7	1.50	Off-peak: 0:00-7:00

Jurisdiction Tariff	Periods per day	# off-peak hours	Peak-off-peak price ratio	Notes
Peak: 7:00-0:00				
Alderney				
Storage Heaters	3	11	1.65	Separate circuit. Only supplied 23:00-7:00 and 12:30-15:30. Peak-off-peak ratio is relative to standard Flat Rate. Includes fuel cost component of 22.36 p/kWh.
Cyprus				
Domestic – Two-rate	2	10	1.16	Off-peak: 23:00-9:00
Commercial and Industrial				
LV – Winter	2	10	1.10	Winter: October-May Summer: June-September Off-peak: 23:00-9:00. Lower rates on weekends.
LV – Summer			1.46	
MV – Winter			1.11	
MV – Summer			1.50	
HV – Winter			1.12	
HV – Summer			1.56	
Guernsey				
Domestic and Non-Domestic Super Economy	3	12	2.22	Number of customers per peak / off-peak band is limited in order to help balance the network. Example off-peak time bands: 21:30 – 7:30 and 14:10 – 16:10
Super Heat + Heat Pump	-	-	1.95	Single rate tariff for electric heaters, boilers, underfloor heating, and heat pumps. Requires external controls that allow interrupting supply up to 30min within a 24-hour period up to four times per year. Peak-off-peak ratio reflects rate relative to standard flat rate.
Industrial (75 kW+) LV	2	9	2.00	Low rate: 20:30-6:30 High rate: 6:30-20:30
Industrial (75 kW+) HV			2.05	Maximum demand charge applies for Nov-Mar.
Ireland				
NightSaver	2	9	1.41-2.06 ¹	Winter off-peak: 23:00-8:00 Summer off-peak: 0:00-9:00
Smart meter	3	9	1.41-2.17 ¹	Tariff periods example: Night: 23:00-8:00 Day: 8:00-17:00 and 19:00-23:00 Peak: 17:00-19:00

Jurisdiction Tariff	Periods per day	# off-peak hours	Peak-off-peak price ratio	Notes
				Examples of special rates on weekends or select time periods.
Smart meter (EV tariffs)	4	3	5.48-6.79 ¹	Ratio relates to four period TOU with special low EV rate for 2:00-5:00
Jersey				
Economy 7	2	8	1.98	Off-peak: typically 23:00 – 7:00. Set on customer-by-customer basis.
Economy 20 / 20 Plus		20	1.43	Approved central heating and hot water systems. Power supply interrupted 4 hours per day under Economy 20. No interruption for Economy 20 Plus, where higher rate then applies.
Comfort Heat		4 (comfort heat + 8 (low period))	1.82	Approved home and water heating on dedicated supply circuit. Comfort heat: four hours between 0:00-7:00 Low period (all other appliances): 23:00-7:00 Normal period: 7:00-23:00
Economy 7 LV (3-phase)		8.5	1.50	Off-peak: typically 23:00 – 7:30. Exact times set by Jersey Electricity. Maximum demand charges apply, which vary by season.
Economy 7 HV (3-phase)	1.45			
Malta				
Non-Residential Property	2	6 ²	1.26	Day / Night pricing available if annual consumption exceeds 5,000 MWh.
EVs	2	10	1.14	Off-peak: 0:00-5:59, 12:00-15:59, and all-day Sunday.
Northern Ireland				
Economy 7	2	8	2.05-2.37 ³	Winter off-peak: 1:00-8:00 Summer off-peak: 2:00-9:00

Source: Sourced from relevant utility websites as of June 2024. Excluding standing charges. ¹Range of peak to off-peak ratios from a sample of offers sourced from [bonkers.ie](https://www.bonkers.ie). ²Not clearly defined on Enemalta website. Assumption based on EV tariff. ³Range of peak to off-peak ratios reported on the Consumer Council For Northern Ireland's [Economy 7 Price Comparison Table](#) as of 6 June 2024. Excluding special discounted rates offered by SSE Airtricity to new customers, which, if included, would lower the minimum ratio to 1.66.

Observations include:

- With the exception of Ireland, where hourly prices are more volatile (Figure 2), two-part tariffs are more common. However, the periods selected vary with EV focused tariffs drawing on a narrower nighttime lull.

- Guernsey, like MU's Comfy Heat tariff, has an additional midday off-peak period, with the exact time bands assigned on a customer-by-customer basis. Alderney's storage heater tariff also has a midday 'boost' period.
- The peak-to-off-peak ratios for the Isle of Man, which range from 1.36 to 1.71, appear to be smaller than prevailing ratios in Guernsey (1.95-2.22) and Jersey (1.43-1.98).
- Seasonality is only explicitly implemented in Cyprus, where there is a significant summer demand peak.
- The most extreme ratios are for tariffs specifically applied for nighttime (2:00-5:00) charging of EVs in Ireland, where we see ratios of 5.5-6.8 relative to the 17:00-19:00 evening peak. Higher ratios for EV tariffs are also apparent in GB (Table 10). While the hourly wholesale cost of overnight EV charging should be lower, marketing, rather than economic principles, are likely driving such offers.

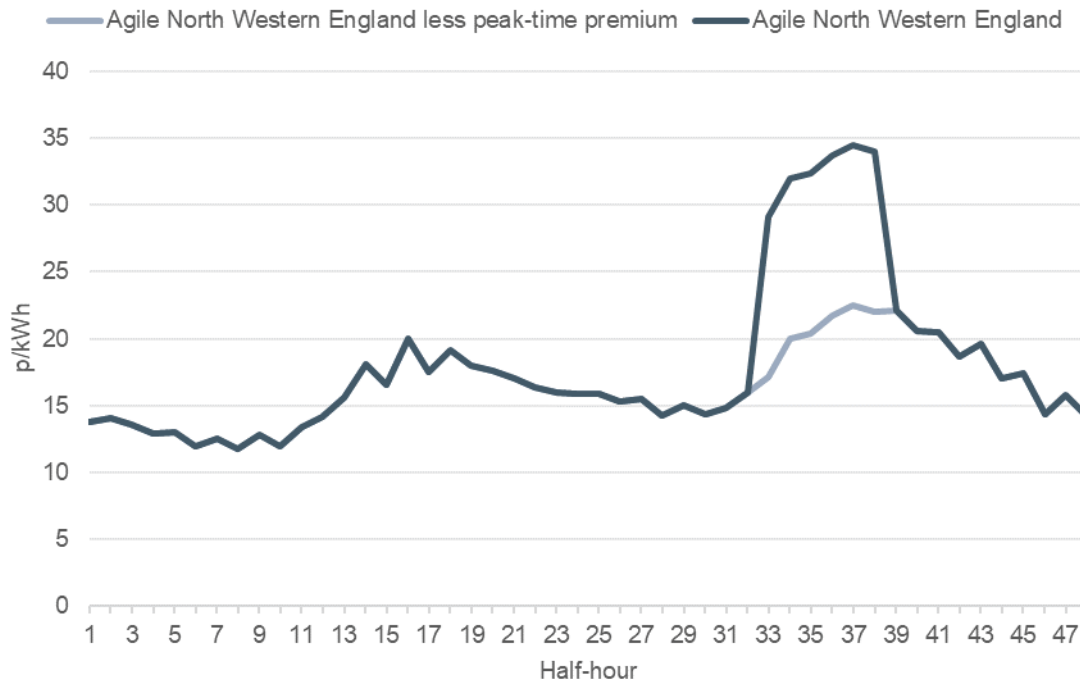
Great Britain

In GB, which has a liberalised electricity supply sector with a number of different retailers³⁴, some retailers have experimented with more dynamic TOU tariffs. The most radical is Octopus' Agile tariff, where the price faced by consumers varies by half-hour in line with GB wholesale prices.³⁵ While half-hour Agile tariffs for 2023-24 are notably peaky in the evening (Figure 5), with a peak-to-minimum price ratio of 2.92, this is primarily a function of the 11-14 p/kWh 'peak-time premium', which is geared towards recovering peak transmission and distribution charges and capacity market costs. Once this is stripped out, the ratio falls to 1.91 and the price shape aligns with the average hourly GB wholesale prices in Figure 2. This highlights the limitations of purely volume-driven electricity tariffs when peak charging-based network costs also need to be recovered, which contributes to a narrower / peakier peak period.

³⁴ As of April 2024, Ofgem [reports](#) that GB has 20 active electricity and/or gas suppliers. This number has significantly fallen from a peak of 70 in mid-2018, largely due to the fallout of the 2021-22 energy crisis.

³⁵ The Agile half-hourly pricing formula is $\min(D+W+P, 95)$, where D is a coefficient set to recover distribution costs (the coefficient is typically around 2.2, it varies by location), W is the wholesale price of electricity, and P is a peak-time premium of 11-14p/kWh that applies 16:00-19:00, which is aimed at recovering peak transmission and distribution charges and capacity market costs. The price is capped at 95p/kWh (100p/kWh after applying VAT). Octopus has been gradually increasing this price cap, which was originally set at 35p/kWh in 2018 before rising to 55p/kWh in July 2022, 78p in August 2022, and then 100p/kWh in late 2022.

Figure 5 Octopus Agile North-Western England average half-hourly tariff, 7 June 2023 – 6 June 2024



Source: <https://energy-stats.uk/octopus-agile-north-western-england/>. Average half-hourly prices for last 365 days, accessed on 7 June 2024. Assuming peak-time premium of 12 p/kWh for 16:00-19:00.

We report a selection of TOU tariffs in Table 10, most of which come from Octopus who are an especially active tariff ‘designer’ in the market (particularly after the dramatic fall in retailers over the past five years), plus a few other retailers offering EV- and heat pump-specific tariffs (which are likely partly driven by marketing effects).

Table 10 Selection of TOU / Economy 7 tariffs in Great Britain

Tariff	Periods per day	# off-peak hours	Peak-off-peak price ratio ¹	Notes
Dynamic and low-carbon technology-specific TOU tariffs				
Octopus Agile	-	-	2.92	Dynamic half-hourly tariff, with a peak-time premium and 100p/kWh price cap. Includes half-hours of negative prices when GB wholesale prices go negative.
Octopus Cosy	3	6	2.96	Designed for heat pumps. Off-peak: 4:00-7:00, day: 19:00-4:00, 7:00-13:00, peak: 16:00-19:00
Octopus Intelligent Go	2	6	3.64	Designed for EVs. Off-peak applies 23:30-5:30
Octopus Tracker	1	-	2.90 ¹	Flat daily unit rate determined by formula linked to previous day’s day-ahead auction for GB wholesale market.

Tariff	Periods per day	# off-peak hours	Peak-off-peak price ratio ¹	Notes
OVO heat pump	-	-	2.00 ²	Not TOU-based, but a specific charge for separately metered heat pump consumption.
Ecotricity EV tariff	2	5	3.85	Designed for EVs. Off-peak applies 0:00-5:00.
EDF GoElectric Overnight	2	5	3.27	Designed for EVs. Off-peak applies 1:00-6:00.
EDF Heat Pump Tracker	3	6	1.68	Designed for heat pumps. Off-peak applies 4:00-7:00 and 13:00-16:00.
Economy 7²				
MU Comfy Heat	3	8	1.71	Off-peak: 0:00-6:00 and 14:00-16:00 Peak: 6:00-14:00 and 16:00-0:00
British Gas			2.01	
EDF			2.19	
E.on			2.93	Economy 7 off-peak: typically 0:00-7:00.
Fuse			2.40	For comparison, MoneySavingExpert
Octopus	2	7	2.30	also report the average single rate for GB of 24.5p/kWh under the April-June 2024 price cap, again highlighting that MU's peak TOU rates matching the flat Basic Domestic charge is an outlier.
Ovo			1.61	
Scottish Power			2.14	
Utility Warehouse			4.02	

Source: Octopus tariff data sourced from <https://energy-stats.uk/>, with peak-to-off-peak ratios calculated from last 365 days. All Octopus tariffs reported are for North-Western England, which is likely the most relevant for the Isle of Man as the Isle of Man to England Interconnector lands in Blackpool, England. ¹Ratio of maximum to minimum daily price. ²Ratio of normal electricity rate of 30 p/kWh versus heat pump rate of 15 p/kWh.

²Average rates reported by MoneySavingExpert for April-June 2024.

GB also has a long history (and large selection) of Economy 7 tariffs linked to overnight storage heaters, for which we report peak-to-off-peak ratio examples in Table 10.³⁶ The range of the ratios is notable, ranging from as low as 1.61 to as high as 4.02. Like the tariffs detailed in Table 9, this puts MU's Domestic Comfy Heat ratio of 1.71 on the low end. However, it is worth noting that the MU rate also includes a midday 'boost' period and the GB tariffs need to go beyond wholesale costs recovery at peak.

³⁶ Ofgem's Energy Price Cap applies an overall annual expenditure cap for households based on typical consumption levels and ratios (currently 58% being peak) with suppliers able to set the actual peak and off-peak rates such that the cap is not breached. There is therefore still information to glean from the ratios offered by different suppliers.

3.6.3 TOU tariff design considerations

Rationalising MU's peak- and off-peak tariffs

Unusually, the higher rate for Manx Utilities' two-part tariffs do not differ from the standard flat rate offered for the non-TOU tariff. For example, among the domestic charges effective as of 1 April 2024, the Basic Domestic charge is 28.5 p/kWh, while Domestic Comfy Heat and EVs have a high rate of 28.5 p/kWh and a low rate of 16.7 p/kWh.

This setup is not entirely unique - Jersey also offers on-peak TOU rates that are the same as the standard non-TOU rate - but it violates cost reflectivity and revenue-neutrality. The peak rate should be higher than the standard rate and the off-peak rate should be lower.

MU sets restrictions on what customers can access the two-part tariff. Otherwise, every customer would simply seek to switch to the TOU tariff (subject to higher standing charges but these are also no different for MU's two-part tariffs). Restrictions include only offering the Comfy Heat tariff to owners of electric storage heaters or heat pumps, the EV tariff to EV owners, and setting load and consumption limits for commercial and industrial customers on the two-part tariffs. However, under the current setup, these rates effectively serve as volume subsidies.

Cost variation and number of TOU periods

Time-of-day costs will vary according to available supply and geography. Reviewing our comparator jurisdiction TOU tariff data in Table 9:

- A key caveat is the extent costs are recovered on a per kWh basis³⁷, but reviewing the peak-to-off-peak ratios in Table 9, we see a wide range, particularly when considering 'special' tariffs for EVs. Excluding the EV tariffs, a rough average ratio is 1.8-2.0 and, excluding Malta and wintertime Cyprus, a minimum peak premium of 40%.
- In Cyprus a significant summer demand peak puts the focus on higher prices in the summer.
- Guernsey and Jersey will be heavily influenced by import arrangements from the nuclear-dominated French grid. Alderney is reliant on a single oil-fired generator whose variable costs will not vary much across the day.
- As illustrated in hourly GB and SEM wholesale prices in Figure 2, there is usually a clear case for at least two TOU periods in northern climates, with a high price during the morning and / or evening peak and a lower price overnight and during the day. As per Section 3.6.1, this is the most relevant benchmark for the Isle of Man.

While more granular TOU pricing may imply greater economic efficiency gains (with GB's Octopus' dynamic half-hourly Agile tariff a notable example), for a "standard" TOU tariff,

³⁷ Prevailing GB wholesale prices imply a peak-to-off-peak ratio of 1.9 but the actual ratios on offer (Figure 4) are 2-3, reflecting the recovery of network peak charges and capacity costs.

additional periods should only be implemented if underlying costs are materially differentiated. Otherwise, they may add unnecessary complexity with little added efficiency gain.

Different time periods for two-part tariffs are correlated with the technology focus they are seeking to support. Adding additional time periods to create 3+ part tariffs can help make a single structure more flexible to these different profiles, negating the need for separate tariff categories. Considering the Isle of Man's interlinkage with the GB market, wholesale price differentials are not extreme. Nevertheless, once metering capability enables, a 3-part tariff separating the evening peak (16:00-22:00) and nighttime lull (1:00-5:00) may help provide suitable price signals to EV owners and electric heating users alike.

Further questions relate to the extent to which such tariffs are imposed on customers or left as opt-in only and what options should be offered to consumers while the smart meter rollout remains partially complete.

Optional or mandatory

The principle of cost reflectivity implies that TOU tariffs should be mandatory. However, it is rare for utilities to make TOU tariffs mandatory, except for relatively large customers, due to a few risks that need to be considered:

1. **Price risk:** TOU tariffs can be a 'win-win' for utilities and consumers but rate setters need to be wary as to what extent consumers are ready / able to assume price risk.³⁸ Price risk has traditionally been borne by utilities, who are able to hedge such risks themselves. In exchange, consumers pay a premium on flat rate tariffs.
2. **Perceived fairness and consumer consent:**
 - a. Utilities need to be conscious of the importance of maintaining consumer consent given their position as a natural monopoly.
 - b. Are all consumers sufficiently willing / able to respond to TOU tariff price signals? There will always be debates about TOU tariffs having 'winners and losers'³⁹, but the prospect of mandatory TOU tariffs usually brings dissenting customers and media coverage.⁴⁰ TOU tariffs should be implemented with caution for smaller, domestic customers.
 - c. Consent is not solely with respect to consumers resisting TOU tariffs. There is also a growing minority of engaged 'prosumers', eager to embrace the energy transition and optimise LCTs. On the Isle of Man, such consumers will be well-aware of the dynamic TOU offerings of retailers in neighbouring

³⁸ For an extreme example, see the fallout of Texas' 2021 Winter Storm, where the wholesale electricity price jumped to US\$9/kWh (~£7/kWh). Some consumers on real-time rate plans ran up multi-thousand dollar monthly electricity bills: S. Najmabadi, 22 February 2021, [Texans blindsided by massive electric bills await details of Gov. Greg Abbott's promised relief](#), *The Texas Tribune*.

³⁹ Conversely, some consumers are de facto 'winners' from the flat rate status quo.

⁴⁰ For example, headlines may arise about the increased cost of cooking. Christmas dinner. Playing off this, customers of Octopus' dynamic Agile tariff were given free electricity between 11:00-15:00 on Christmas Day in 2018: <https://octopusgroup.com/newsroom/latest-news/octopus-customers-are-squids-in-on-xmas-day/>

Great Britain or Ireland, including real-time pricing tariffs. Consent for such consumers entails offering more complex TOU tariffs.

3. Revenue forecasting risks:

- a. A potential mismatch in MU's revenue and system cost savings. As consumers respond to the price signal brought by TOU pricing, this may lead to an overall decline in consumption. This may be societally beneficial, but could have a net detrimental impact on MU's revenues, at least in the short-term.
 - i. In terms of fuel costs, the risk is MU over-contracting on fuel. This is only a short-term risk and can be mitigated
 - ii. System capex is a longer-term risk if MU over-invests in network capacity, but this risk should recede as the impact of TOU pricing is incorporated into network planning forecasts. This is also not a relevant concern for MU in the present context of an un-congested system and stagnant peak load.
- b. TOU pricing brings the risk of 'self-selection' by 'passive winners': more consumers who already have a 'sympathetic' consumption pattern and financially benefit from a shift to TOU tariffs without significantly changing their load profile, with financial consequences for the utility.
 - i. This risk can be mitigated by carefully modelling the heterogeneity of consumer load rather than overly focusing on an average customer load curve. For the initial period after implementation (eg the duration of this Pricing Strategy Review) MU may also include annual reviews to review response and revenue collection with an appropriate amendment to the TOU tariff rates should there be a notable discrepancy with forecasts.

We, therefore, caution against making TOU tariffs mandatory for all customers.

However, we recommend that TOU tariffs should be mandatory for larger customers. Such customers are more likely to have 'unsympathetic' load profiles, which can materially exaggerate MU's load / cost profile. Such customers should be sufficiently able to actively adjust their load in response to TOU incentives and manage the associated price risk. If TOU were left as 'opt-in' for larger customers, the associated self-selection risk would be larger compared to smaller customers.

Offering a single "standard" three-rate TOU tariff to all customers

Given there is no disadvantage to the current set of TOU tariffs in the Isle of Man - customers benefit from a lower off-peak rate and the peak rate is no higher than the standard rate, and there are no higher peak charges - MU currently rations TOU tariffs:

- Consumers must consume 30% or more of their electricity during the off-peak period.
- Comfy Heat is only available for customers with a minimum of 6 kW heating load.

This is effectively a volume discount, which is not justified by cost reflectivity principles.

One argument may be that the discount for Comfy Heat has social implications given evidence that storage heaters are more common among less affluent households. However, as with the discussion regarding standing charges, social considerations are best addressed through explicit support the draws on welfare criteria for eligibility (or simply left to tax and welfare policy itself) rather than imperfectly targeted subsidisation of energy volumes. Furthermore, given more affluent households are likely to have heat pumps and now benefit from the Comfy Heat tariff, the tariff itself is likely to increasingly become regressive.

We, therefore, **recommend that a single three-tier “standard”⁴¹ TOU tariff** is made available to all customers with sufficient metering technology.⁴² This eliminates the de facto volume subsidy and reduces the added complexity of verifying customers’ qualification. Customers yet to have a smart meter installed may be allowed to continue with the current two-tier TOU tariff options until such time as the rollout is complete.

The TOU rates should be set such that customers with LCT are already incentivised to shift their load in a manner that benefits the grid. Where LCT technologies are providing network and balancing services through remote load control, these could in future be considered for direct incentive payments by MU rather than via volume discounts (Section 3.6.4).

3.6.4 Implications for special tariffs

Private generation

The economic principles that drive TOU consumption tariffs should also drive TOU export tariffs for private generation. The tariff for exports to the grid should be aligned with the hourly economic value of supply.

In Table 11, we report prevailing export tariffs for private generation in our comparator jurisdictions. We include in the table only those tariffs available either to all consumers, or those with the same energy supplier. There are further tariff options offered by various suppliers that have specific conditions regarding the presence of BESS and/or require the solar PV system to have been installed by the supplier themselves. These restrictions indicate cross-selling⁴³ and therefore are not considered to be like-for-like benchmarks for this review.

In GB, we report two different options offered by Octopus, where we can see the contrast between the flat ‘Outgoing Fixed’ rate and the dynamic Agile rate, which varies by half-hour according to hourly GB wholesale prices. Also reported are Good Energy Solar Savings which, like Octopus Fixed, requires the prosumer to have the same entity as supplier but no further restrictions, and Scottish Power’s Smart Gen which at the time of writing is reported as the most generous export tariff with freedom to select any supplier for imports.

⁴¹ The use of “standard” here is to differentiate from a trial of a novel granular (hourly) TOU tariff option.

⁴² There may be a ‘postcode lottery’ element for households lucky enough to have received smart meters and benefit from TOU tariffs, but it would also be unfair to hold back such offers and indirectly impose higher system costs on all households. Given the potential of TOU tariffs is often touted as a key part of the benefits of smart meter CBAs, it would be appear odd to actively delay those potential benefits amid a major capital outlay.

⁴³ BESS restrictions can also include remote control of discharge and charging profiles reflecting additional benefits such as certain network or ancillary service provision.

We can see that certain suppliers in GB, Ireland, and Northern Ireland currently offer more generous rates than those offered on the Isle of Man (9.5 p/kWh), Guernsey (9.9 p/kWh), or Jersey, which has the lowest rate at 8.69 p/kWh. Given some of these rates are significantly above the wholesale price of electricity it seems likely the suppliers in question see marketing benefits for customer switching. It is also notable that these rates have doubled from the best available just two years' previous when the wholesale energy price crisis peaked 2022.⁴⁴ This indicates a lag in the setting of export rates relative to wholesale prices (and suggests we may see a fall in the near future reflecting the recent decline in wholesale market prices).

Table 11 Export tariffs for private generation in other jurisdictions

Export tariff	Export rate (p/kWh)
Isle of Man: Sustainable Generation	9.5
	Max: 31 / Min: 0
GB: Octopus Agile (half-hourly)	Peak (16:00-19:00) average: 15.8 Off-peak (2:00-5:00) average: 6.4
GB: Octopus Outgoing Fixed	15
GB: Good Energy Solar Savings	15
GB: Scottish Power Smart Gen	12
Guernsey: Buy-back Domestic / Commercial	9.9
Ireland	13.6-21.4 ¹
Jersey: Buy Back Domestic / Commercial	8.69
Northern Ireland: Export	14.22 ²

Source: <https://energy-stats.uk/>, [Which?](#), and relevant utility websites. Values for past 365 days. Excluding Cyprus and Malta from this comparison given materially different solar potential. ¹Range of FiT rates reported by switcher.ie as of December 2023. Applying GBP:EUR exchange rate of 1.17. ²Export tariff reported by [Power NI](#), as determined by the Utility Regulator.

With network and generation capacity costs largely fixed, export tariffs should be driven overwhelmingly by coincident wholesale costs. There are potentially some further benefits that may be gained through localised consumption reducing network losses but this will be highly dependent on locality and could be counter-balanced by additional balancing and voltage control costs. The principal benefit to MU of electricity purchased from customers is allowing MU to either export more electricity to the GB market or avoid high wholesale prices.

In our previous review in 2018, we noted that MU's Sustainable Generation tariff was higher than prevailing GB wholesale costs and recommended that the tariff be lowered, while noting that government policy considerations may favour a continuation of the effective subsidy. However, with GB wholesale prices still relatively elevated in the aftermath of the 2021-22 gas price crisis (averaging £73/MWh in last 12 months), this recommendation is less urgent, particularly with political preferences for RES self-supply likely even further strengthened.

⁴⁴ This is Money. 11 September 2022. [Solar panel sales are soaring - but NOT the price energy firms pay you for power: Paltry rates for electricity generated by households](#)

EVs and heat pumps

Decarbonisation policy goals will push for rapid heat pumps and EVs adoption, which is raising questions for regulators and utilities looking to avoid adoption bottlenecks while maintaining both grid stability and cost reflective network charges.

We have noted cases of suppliers offering TOU tariffs specifically tied to LCTs. This is not a new concept given the long history of Economy 7 meters linked to overnight storage heaters. However, we do not see the reason to discriminate TOU tariff offers. If a tariff has been designed in cost reflective terms for both TOU and fixed charges, the incentive should already be there for EVs / heat pumps to shift their load in a manner that is most efficient for the grid at large.

Capital grants are usually a better and simpler approach to encouraging LCT adoption. As observed in Guernsey and Jersey, as well as Germany⁴⁵, some LCTs can offer additional services to the grid, eg, allowing for supply throttling during times of system stress to avoid high wholesale prices. In such cases, consumers can be directly compensated for offering a service to the grid, either through demand / standing charge discounts or other side payments, rather than receiving a blunt volume subsidy.

Having network residual costs recovered through volumetric pricing does disproportionately burden EV and heat pump owners who, all else equal, will have higher demand than a similar household with an ICE vehicle or gas heating. Nevertheless, we consider this insufficient justification for a separate tariff with a volume discount and better managed through offering the option of an opt-in tariff with a combination of both higher fixed charges and lower unit rates (our initial proposition is for the trial of a granular TOU tariff with an ASC component sized to recover residual network costs as discussed in Section 3.4).

3.6.5 Recommendations

- The research presented above provides mixed evidence for altering the current ratio of peak for MU's existing TOU tariffs. Its peak-to-off-peak ratios are on the low side of our comparator jurisdictions, particularly relative to the most relevant benchmark, the GB market.
- The Isle of Man remains an outlier in having two-part tariffs where the peak rate matches the standard flat rate. This conflicts with cost reflectivity and revenue-neutrality. Two-part tariffs should be amended so that compared to the standard flat rate the peak rate is higher and the off-peak rate is lower.
- MU should offer a single "standard" opt-in TOU tariff that is available to all domestic and commercial customers with capable smart meters.

⁴⁵ Germany's energy regulator, BNetzA, recently temporarily allowed grid operators to throttle electricity supply to heat pumps and EV charging points from January 2024 in order to maintain grid stability. In return, distribution grid operators must offer reduced fees and cannot refuse or delay connection of new heat pumps or charging stations – effectively a 'connect and manage'-style compromise: C. Kyllmann, 28 November 2023, [German grid operations allowed to throttle electricity in bid for faster expansion of heat pumps, EV chargers](#), *Clean Energy Wire*.

- Households with LCTs will likely opt-in to such tariffs and adjust their consumption in a way that is beneficial to the grid.
- This should also eliminate the current added complexity of having to verify if customers qualify for TOU.
- This offer need not be delayed until the smart meter rollout is 100% complete with customers yet to move to a smart meter allowed to be grandfathered on the legacy two-rate tariff options.
- The standard TOU tariff could be expanded to a three-part approach to capture the relative benefits of different LCTs. The higher rate would be focused solely on the evening peak period of 16:00-22:00, the low rate on the nighttime lull of 1:00-5:00, with all remaining times designated as shoulder periods.
- MU may consider experimenting with real-time pricing-based tariffs in order to engage with the growing minority of 'prosumers', maximise the potential system benefits from the rollout of smart meters and LCTs. As discussed in Section 3.4, such a granular TOU tariff option may be paired with a cost reflective ASC charge and marketed to appeal to high demand EV and heat pump owners (but not be restricted to them).
- TOU tariffs should be opt-in for domestic households, accounting for consumer consent and price risk preferences. Revenue risk to MU due to "passive winners" who opt-in and benefit due to their existing load profile without any response to the tariff can be managed through annual reviews of uptake, revenues and smart meter data with corresponding adjustments as required.
- TOU tariffs should be mandatory for larger consumers, whose load profiles are mostly likely to exacerbate MU's load and cost profile and are likely best able to adjust their loads accordingly and manage price risk.

3.7 Reflecting reactive power costs

In an Alternating Current (AC) circuit the amount of real ("active") power consumed by a load depends on the phase angle between the voltage and current waveforms. Differences in phase generate reactive power which is not consumed but creates current and thereby requires line capacity. Total ("apparent") power is made up of active and reactive power with the power factor representing the ratio of active to apparent power. A high power factor therefore represents greater efficiency in converting transported power into useful power.

Reactive power may be charged at a penalty rate where a consumer deviates below a pre-specified power factor (some degree of reactive power is necessary for active power to flow). Excess reactive power takes up network capacity. Given the declining electricity demand on the Isle of Man, as with network charges more broadly, cost reflective reactive power charges may be negligible and insufficient to incentive any change in behaviour by consumers. Nevertheless, this context may change in future years and introducing penalties at a nominal level for reactive power below a suitable level (0.90 or 0.95 are commonly used levels in Europe) may be preferable. For reasons of avoiding complexity and given the lack of current benefit from cost reflectivity, we recommend such penalties be limited to larger consumer

(defined either as HV connected or those with maximum demand in excess of 50 kVA for alignment with current tariff products).⁴⁶

3.8 Electricity tariff design recommendations

A summary of our recommendations on electricity tariff design for the forthcoming pricing strategy period is as follows:

- Customers to remain categorised as at present into domestic and business industrial/commercial (also termed “business”) categories. The latter group may be subdivided as at present by connection voltage and maximum demand. Unlike at present the former could be used for allocating network costs. Maximum demand may be amended to connection capacity should the below recommendation on ASC be adopted.
- For all tariffs that currently incur both a Maximum Demand charge and ASC, for these to be aggregated into a single ASC charge. As a compromise between recovering a higher proportion of fixed network costs through the ASC and avoiding unduly large tariff amendments, we recommend a rate of £9.17/kVA/month, similar to that in Guernsey and Jersey. The balance of residual fixed network costs would remain, as at preset, recovered through volumetric (unit) charges.
- For reasons of simplicity and consumer consent to not introduce mandatory ASC charges for standard domestic and smaller commercial customers with fixed network costs remaining recovered through volumetric pricing. In the case of the two-part TOU tariff this may be applied as an uplift solely to the higher rate.
- To apply a mandatory ASC to two special tariff categories:
 - The sustainable generation tariff for private generation to recover the avoided fixed costs that accrue from volumetric pricing of fixed cost recovery. Assuming the unit rate is the same as for other consumers, our initial estimate of this ASC is £6.29/kVA/month.
 - To a new trial cost reflective tariff option that encompasses both granular TOU pricing (hourly) and an ASC sized to recover the full consumer’s proportionate share of fixed network costs. This is estimated at £14.07/kVA/month. The volumetric (unit) cost element would be commensurately lower.
- To retain standing charges as the preferable means to recover costs associated with customer-related activities (billing, metering, collections and customer liaison etc) and to raise these to 45p/day for LV and 134p/day for HV customers which is estimated to enable full recovery of relevant costs.

⁴⁶ See Ofgem. 2019. [Charge design options for distribution and transmission charges – discussion note](#), Annex A, for a similar discussion on reactive power charging in Great Britain.

- To manage concerns regarding vulnerable consumers through targeted rebates or a social tariff for eligible recipients rather than a block tariff structure that creates wider distortions.
- Should a social tariff be deemed desirable to structure it simply (eg lump sum payment to qualifying households or percentage reduction in tariff – unit rate and/or standing charge - up to a cap) and drawing on the existing welfare system to target support.
- To introduce a new “standard” opt-in two-tier TOU tariff that is available to all domestic and commercial customers with capable smart meters. The higher rate for this tariff should be above the fixed rate of the single tier tariff with the lower rate below the fixed rate level. Households yet to receive a smart meter may be grandfathered on the prior tariff arrangements.
- The standard TOU tariff could be expanded to a three-part approach to capture the relative benefits of different LCTs. The higher rate would be focused solely on the evening peak period of 16:00-22:00, the low rate on the nighttime lull of 1:00-5:00, with all remaining times designated as shoulder periods.
- To consider experimenting with a real-time pricing-based tariff in order to engage with the growing minority of ‘prosumers’, maximise the potential system benefits from the rollout of smart meters and LCTs. This may take the form of an opt-in granular (hourly) TOU tariff option paired with a cost reflective ASC charge and marketed to appeal to high demand EV and heat pump owners (but not be restricted to them).
- Revenue risk to MU due to “passive winners” who opt-in to TOU options and benefit due to their existing load profile without any response to the tariff can be managed through annual reviews of uptake, revenues and smart meter data with corresponding adjustments as required.
- The TOU tariff to be mandatory for larger consumers, whose load profiles are mostly likely to exacerbate MU’s load and cost profile and are likely best able to adjust their loads accordingly and manage price risk.

The above recommendations lead to a revised set of tariffs, scaled to meet the average annual required revenues in real terms for the five-year period 2023/24 to 2027/28 as given by the Long Term Financial Plan. These are provided in Table 12 below.

Table 12 Revised electricity tariffs to achieve the forecast annual average revenues for 2023/24-2028/29

Tariff categories	Component	Existing level	Proposed tariff	Component	Proposed level
Domestic and prepayment	Unit	28.5 p/kWh	Domestic and prepayment	Unit	28.3 p/kWh
	SC	24.6 p/day		SC	44.8 p/day
Domestic – Comfy Heat	Unit – peak	28.5 p/kWh	Domestic Three-tier TOU	Unit - peak	37.8 p/kWh
	Unit - off-peak	16.7 p/kWh		Unit - shoulder	26.1 p/kWh
	SC	24.6 p/day		Unit – off-peak	14.7 p/kWh
Domestic – Electric Vehicle	Unit – peak	28.5 p/kWh		SC	44.8 p/day
	Unit - off-peak	19.0 p/kWh			
	SC	24.6 p/day			
Sustainable Generation	Unit	-9.5 p/kWh	Sustainable Generation	Unit	-9.5 p/kWh
				ASC	6.3 £/kVA/m
Commercial	Unit	28.5 p/kWh	Commercial	Unit	27.6 p/kWh
	SC	24.6 p/day		SC	44.8 p/day
Economy 8 Commercial	Unit – peak	28.5 p/kWh	Commercial Three-tier TOU	Unit – peak	37.8 p/kWh
	Unit - off-peak	18.0 p/kWh		Unit - shoulder	26.1 p/kWh
	SC	24.6 p/day		Unit - off-peak	14.7 p/kWh
Commercial Plus	Unit – peak	28.5 p/kWh		SC	44.8 p/day
	Unit - off-peak	16.7 p/kWh			
	SC	24.6 p/day			
Electric Vehicle Commercial	Unit – peak	28.5 p/kWh	Three-tier Demand LV	Unit – peak	28.9 p/kWh
	Unit - off-peak	19.0 p/kWh		Unit – shoulder	21.6 p/kWh
	SC	24.6 p/day		Unit – off-peak	14.7 p/kWh
Industrial Demand LV	Unit	25.7 p/kWh		ASC	9.17 £/kVA/m
	MD	2.76 £/kVA/m		SC	44.8 p/day
	ASC	1.51 £/kVA/m			
	SC	42.9 p/day			
Economy 8 Demand LV	Unit - peak	25.7 p/kWh			
	Unit – off-peak	18.0 p/kWh			
	MD	2.76 £/kVA/m			
	ASC	1.51 £/kVA/m			
	SC	42.9 p/day			
Industrial Demand HV	Unit	25.7 p/kWh	Three-tier Demand HV	Unit – peak	22.3 p/kWh
	MD	2.76 £/kVA/m		Unit – shoulder	18.1 p/kWh
	ASC	1.51 £/kVA/m		Unit – off-peak	14.3 p/kWh

Tariff categories	Component	Existing level	Proposed tariff	Component	Proposed level
Economy 8 Demand HV	SC	42.9 p/day		ASC	9.17 £/kVA/m
	Unit - peak	25.7 p/kWh		SC	134.3 p/day
	Unit – off-peak	18.0 p/kWh			
	MD	2.76 £/kVA/m			
	ASC	1.51 £/kVA/m			
High Load Factor	SC	42.9 p/day			
	Unit	19.2 p/kWh			
	MD	2.76 £/kVA/m			
	ASC	1.51 £/kVA/m			
High Volume	SC	42.9 p/day			
	Unit	24.4 p/kWh			
	MD	2.76 £/kVA/m			
	ASC	1.51 £/kVA/m			
High Volume 2 Rate	SC	42.9 p/day			
	Unit - peak	24.4 p/kWh			
	Unit – off-peak	18.0 p/kWh			
	MD	2.76 £/kVA/m			
	ASC	1.51 £/kVA/m			
Public Lighting	SC	42.9 p/day			
	Unit	27.6		Unit	27.1

Source: Consultant calculations

The average electricity price by existing tariff category is shown in Table 13 below, expressing all costs (unit rates, ASC and standing charges) in per kWh terms based on consumption profiles and load factors guided by consumption data and consultant judgement. Average prices may differ between categories proposed for merging into a single group due to these different consumption profiles and load factor assumptions.

Table 13 Average electricity prices by tariff category for 2023/24-2028/29

Tariff category	Average p/kWh
Domestic and prepayment	33.4
Domestic – Comfy Heat	28.2
Domestic – Electric Vehicle	25.9
Sustainable Generation	-6.2 (effective export tariff with ASC applied)
Commercial	29.4
Economy 8 Commercial	28.9
Commercial Plus	26.7
Electric Vehicle Commercial	23.5

Tariff category	Average p/kWh
Industrial Demand LV	26.5
Economy 8 Demand LV	26.0
Industrial Demand HV	23.5
Economy 8 Demand HV	22.5
High Load Factor	21.4
High Volume	20.4
High Volume 2 Rate	22.5
Public Lighting	27.1

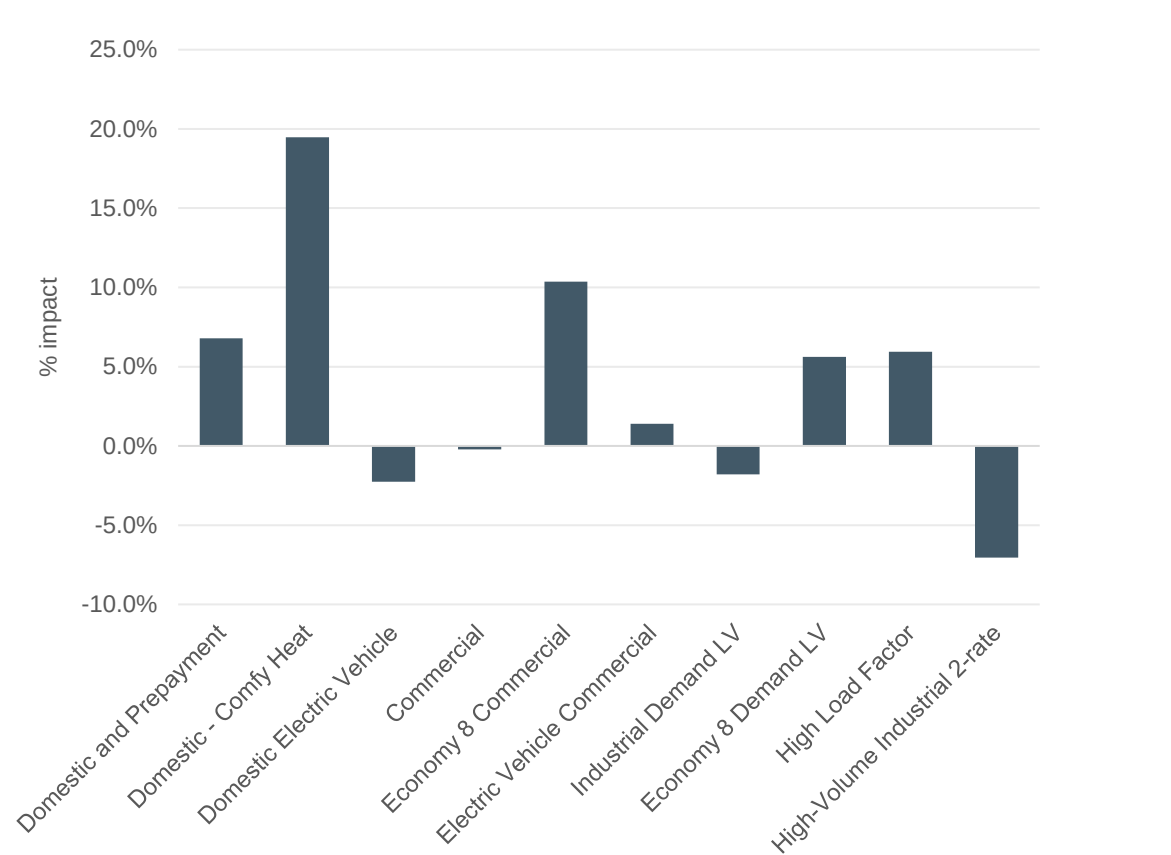
Source: Consultant calculations

3.9 Impact analysis of recommended proposed tariffs design and levels

As with any amendment to tariff structures and products, there will be consumers groups better and worse off than previous. The impact on key customer groups is shown in Figure 6 below. The larger impact is seen on those groups currently on two-rate tariffs. This is due to the current system setting the higher rate equal to the fixed rate for other single-tier tariffs and the lower rate significantly below. As discussed in Section 3.6 this is not a cost reflective approach and effectively makes such tariffs preferable for any customer that is eligible to avail.

We note that the Domestic Comfy heat tariff which sees the largest percentage increase (being converted into a common three-tier TOU tariff) may currently have social objectives due to the prevalence of electric heating (although not via heat pumps) among lower income households. As discussed in Section 3.2, we recommend such objectives are met either directly through the welfare system or via a specific social tariff of the design described.

Figure 6 Impact of proposed tariff amendments on key current tariff categories



Source: Consultant calculations

4 Tariff design – water and wastewater

The previous Pricing Strategy Review in 2018 recommended:

- Against the introduction of mandatory metering of domestic water on the basis of a prior cost-benefit analysis (supported by a high level update at the time) but to implement mandatory metering for larger consumers.
- The retention of pricing by rateable value until such time that the system is reformed with no occupancy adjustments.
- To rebalance charges between water and wastewater as historically the former were disproportionately high.
- To introduce standing charges for both metered and non-metered customers to reflect the fixed costs of supply (albeit to a limited degree given the contentious nature of such charges).
- To retain the prevailing tariff categories but eliminate the discount for commercial customers.
- To harmonise the prompt payment discount with that for electricity.

MU have partially adopted a number of the above recommendations. Unlike in 2018 there are also some concerns regarding the level of strategic storage for water and potential need for reservoir expansion in light of the high per-capita consumption relative to other jurisdictions in the UK. Furthermore, additional data are available regarding the potential for savings from metering. These issues are explored in the following sub-sections culminating in an updated set of recommendations for the sectors to MU.

4.1 Background

4.1.1 Recommendations from the 2018 Pricing Strategy Review

The recommendations provided in the 2018 Pricing Strategy Review, along with the status of their adoption in the Isle of Man are detailed in Table 14.

Table 14 Recommendations from the 2018 Pricing Strategy Review

Recommendation	Status
Water and wastewater pricing recommendations	
Rebalance water and sewerage charges to eliminate cross-subsidisation between services	Largely implemented, with tariff rates broadly reflecting respective costs
Maintain charges to domestic customers to be based on rateable value until the system has been reformed to capital value charging	Retained

Recommendation	Status
Harmonise discount for early payment with that of electricity at 1%	Considered but not applied, different billing cycles may justify differentiation (see below)
Do not introduce charges linked to household occupancy	No occupancy-related charges have been introduced
Continue discounted tariffs offered to charitable and religious premises	Discounted tariffs remain in place
Eliminate existing discount to commercial premises	Partially implemented, discount reduced from 50% to 25%
Introduce standing charges for all customer categories	Considered but not implemented as it was deemed potentially regressive and unnecessary in context of rates-based system which may be considered fixed
Water pricing recommendations	
Retain existing tariff categories	Categorisation broadly unchanged, unmetered categories split between domestic and non-domestic unmetered categories
Ensure mandatory metering for customers above a certain size	Mandatory metering only in place for large non-domestic customers
Wastewater pricing recommendations	
Charges for sewerage should be based on water consumption for customers with metered water	No changes introduced but MU remains open to this recommendation
Consider the introduction of the Mogden formula for charging trade effluent	Not applied, applicability and need for this has been questioned by MU

Source: 2018 Pricing Strategy Review

4.1.2 Key developments in the 2018-2024 period

In the time period since the 2018 Pricing Strategy Review there have been new developments in the sector which were discussed between ECA and MU during a virtual workshop held on 15 May 2024. The new developments to be considered within the new recommendations are presented below and discussed in more detail in the following sub-sections:

1. **There have been steps taken to avoid cross subsidies between water and wastewater charges.** In this regard, MU confirmed that the changes have aimed to equalise the returns from water and wastewater charges.
2. **While the total removal of the 50% discount for commercial premises has not been achieved, it has been gradually reduced to 25%.** This is in part to reflect a desire for a phased approach and avoid a cliff-edge increase. ECA has been requested by MU to assess whether this reduced discount ought to be phased out or if it can be accepted.

3. **There are growing concerns over increasing demand and the implications this has for the functioning of reservoirs.** Issues caused by the increasing frequency of long periods of dry weather through summer have been exacerbated by higher per capita consumption of water first observed during the Covid-19 pandemic and which has not reduced subsequently. To tackle these trends MU has emphasised their concerns over potential constraints in reservoir capacity due to the high investment that would be needed to expand it. Furthermore, the largest of the two reservoirs in the island is located in an area with low demand and thus also supplies the smaller but more utilised reservoir. Increasing demand would thus increase costs incurred in pumping water from one reservoir to another, a potential vulnerability for the water supply system. Ageing transport infrastructure, on the other hand, is not considered to pose a significant threat to the island's supply, and modernisation plans have been proposed.

Another concern related to the high demand is that the Isle of Man only has 12 months of strategic supply of water if precipitation decreases. This is considered insufficient for islands, which face significant difficulties to access water from outside borders. In contrast, under consumption patterns similar with those in Great Britain, the strategic supply storage in Isle of Man would double, and meet the required levels.

4. **While early payment discounts have remained unchanged, MU highlighted differences in the billing cycles for electricity and water/wastewater services.** Currently, it is understood that the 5% discount for early payment of water and wastewater bills, which is allowed by the existing legislation, remains untouched under the same justification (ie smoothing the cashflow for MU to avoid borrowing costs). However, the combination of borrowing cost increases and the difference between the annual billing cycle of water and wastewater services and the quarterly billing cycle for electricity supply could make the harmonisation of the discount undesirable.
5. **The introduction of standing charges has been explored but did not materialise.** MU were concerned about potential bill increases for low income customers and reductions to high income customers if standing charges were to be introduced. This was deemed potentially regressive and given the largely fixed nature of rate-based pricing, standing charges were considered unnecessary.
6. **Potential savings for expanding metering have increased due to reservoir constraints, higher carbon prices, and higher operations and maintenance (O&M) costs.** While metering is crucial for the management and distribution of scarce resources, the relative abundance of water availability in the Isle of Man has resulted in incentives to invest in metering negligible beyond the largest commercial users. However, an update of the carbon prices used to calculate the cost of emissions from pumping, the potential costs from expanding reservoir capacity, and the higher cost of electricity needed to operate pumping stations and water treatment works (WTW), and other O&M costs, are expected to increase these savings, making an expansion of metering to more customer groups more palatable.
7. **Changes on the calculation of sewerage charges and the implementation of a trade effluent charge have not been progressed.** To improve cost reflectivity of sewerage charges, it was recommended in the previous Pricing Strategy Review that these ought to be calculated based on water consumption, which has

not been implemented. MU has stated that they remain open to this change but were not clear on how this would be implemented in practice. In the case of implementing a trade effluent charge, MU has questioned whether this would be necessary due to the overall good wastewater treatment practices of industrial customers, as well as the staff constraints they would face for its implementation.

4.2 Current approach

4.2.1 Water charges

The current design of water tariffs is aligned with the principles of **simplicity** and customer consent at the cost of cost reflectivity. Consumer categories have remained broadly unchanged with a distinction between metered and unmetered customers, which are split between domestic and non-domestic. Discounts of 5% are offered for early payment - ie payment done within the first three months of the financial year.

Metering is not widespread as cost savings from investing in metering expansion have been forecast to be small; compulsory metering is limited to large non-domestic users. For unmetered customers, charging is done on the basis of the rateable value of the property with reduced tariffs offered to charitable and religious premises, and discounts of 25% in place for commercial premises.

The water tariff design is summarised in Table 15 below.

Table 15 Current water tariff design

Tariff category	Basis for charging	Charge
Domestic water	Rateable value of the property	£2.901
Non-domestic water	Rateable value of the property	£2.176
Standard metered supply	Per cubic meter	£1.83

Source: [Manx Utilities - Tariffs, rates and charges](#)

4.2.2 Wastewater charges

Wastewater tariff-setting broadly follows the same approach as for water as it follows the principles of simplicity and customer consent. In this case a distinction is made between customers connected to the sewer system, also divided between domestic and non-domestic, and those using a septic tank. A similar stipulation to early payment discounts for water charges is applied to wastewater charges.

Metering does not have an impact on charges, with all sewer-connected customers being charged based on the rateable value of the property; no distinction or discount is offered to customers without surface water drainage. Reductions of tariffs are also offered to charitable and religious premises, whereas a 25% discount is also offered to commercial premises.

The wastewater tariff design is summarised in Table 16 below.

Table 16 Current wastewater tariff design

Tariff category	Basis for charging	Charge
Domestic wastewater	Rateable value of the property	£2.649
Non-domestic wastewater	Rateable value of the property	£1.987
Septic tank emptying	Per tank up to 9,000 litres	£225

Source: [Manx Utilities - Tariffs, rates and charges](#)

4.3 Water tariff design recommendations

Early payment discount

An early payment discount of 5% is currently offered to customers during the first three months of the financial year (ie from April to June), which was already in place during the 2018 Pricing Strategy Review. The rationale behind offering this discount is to ensure a base level of cash inflows to MU, thus reducing the high borrowing costs that would be otherwise incurred to maintain an appropriate cashflow throughout the year. This rationale remains valid and has become more relevant as borrowing costs have increased substantially since 2018.

The downsides of maintaining this discount, however, are the potential distributional impacts. High income households may be expected to benefit the most from early payment discounts, as they have more flexibility to spend at different times of the year. Low income households, on the other hand, do not have such flexibility, and thus are less likely to benefit from this discount. Nonetheless, this impact is small, and has become less relevant in face of the potential borrowing savings for MU.

Another consideration, which was presented in the previous Pricing Strategy Review, is the harmonisation of the discount regime with that offered to electricity customers at 1%. While it remains to be confirmed whether the legislation mandates early discount for water to be set at 5% or up to 5%, the case for reducing it is now considerably weaker.

Furthermore, the billing periods are different. For electricity billing is done on a quarterly basis with the first 3-4 weeks considered to be the window for early payment discount. Where payment is not received the customer is already considered in arrears and liable for enforcement action although no disconnection is likely for up to 12 months. Prepayment and direct debit customers also automatically receive the 1% discount, the latter regardless of whether their accounting position is in credit or debt at any given point. Conversely for wastewater, billing is annual with bills issued in April each year. Customers who pay by June receive the discount. Those how do not pay by June will have until next March to settle, but reminders will be issues sooner (typically from the autumn).

We have therefore revised our position in relation to the previous Pricing Strategy Review and consider the current early payment discounts for each of electricity and water/wastewater to be acceptable.

Standing charges

While the cost of supplying a service to customers is heavily determined by consumption, auxiliary services that are not consumption-dependent, such as metering and billing, are better reflected through the use of standing charges between all customers receiving the service. Such charges are applied to the water and wastewater services in neighbouring jurisdictions, however, in the Isle of Man, standing charges are applied to electricity, but not to water or sewerage.

The introduction of standing charges, nonetheless, remains a contentious subject. While desirable from an economic perspective as a fair allocation of non-consumption determined costs of supply, it is nonetheless a cost paid equally by all customers regardless of their ability to pay. MU has considered these charges but decided against the introduction of standing charges following evidence of the regressive impact of these, with potential reductions benefitting high income customers while low income customers would face increases.

This problem is common for the introduction of standing charges and is an especially sensitive issue under ongoing increases in the cost of living. In this regard, a degree of practicality is recommended for their introduction and we retain our recommendation for their implementation at a reduced level, especially in the event of mandatory metering as discussed below. Similar to electricity, we consider social policy objectives to best be addressed via targeted support, possibly with a dedicated tariff category and clear eligibility criteria, rather than embedded in the broader tariff design process.

Metering

Metering is not widespread in the Isle of Man except for large commercial users, for which metering is mandatory. With no exact measure of the consumption of a service, a proxy can be used to determine the costs to be covered by each customer, such as rateable value in the Isle of Man. However, this is imperfect as this could result in a lack of incentives to users to efficiently use the service provided, facilitating overconsumption. MU reported that this is currently a problem in the Isle of Man, with per-capita consumption being higher than other jurisdictions.

While the good or service provided does not face any constraints, investments in metering infrastructure may not be offset by the potential savings from accurately charging customers for the service consumed. However, increasing concerns over the adequacy of reservoir capacity, increasing prices of electricity used for pumping and wastewater treatment, and higher carbon prices to emissions from pumping, may have resulted in potential savings offsetting the costs of increased metering.

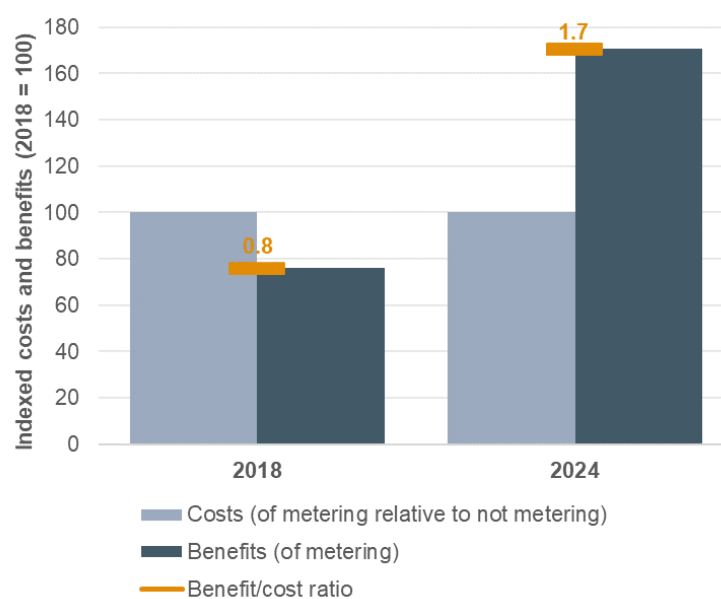
To illustrate the changes that new input assumptions could have on the economic benefits of metering, the following parameters have been updated in the high level cost benefit analysis (CBA) model from 2018:

Table 17 Parameter update from 2018 CBA model for metering

Parameter	Units	Value used in the 2018 Pricing Strategy Review	Value in 2024
Consumption per unmetered household per day	litres/person/day	154.8	168.9
Household size	Person per household	2.28	2.22
Carbon cost	£/tonne CO ₂	21	64.9

Source: Ofwat, DESNZ, 2016 and 2021 Census, MU 2023 Water resources management plan

From these parameters, the increase in the assumed cost of traded emissions significantly increases the benefits of metering, which would now offset the costs. While a more detailed analysis of the other input parameters remains to be performed, the change with respect to 2018 with these updates is significant, as illustrated in Figure 7.

Figure 7 CBA model for metering with updated input parameters

Source: ECA analysis

Other recommendations

- Some deviations from cost reflectivity are expected in order to maintain consumer consent of the tariff regime. Under this consideration, as well as the minimal impact it has on total revenues, offering tariff reductions to charitable and religious premises is recommended to be treated as a policy decision rather than a technical one.
- The reduction of the discount offered to commercial premises is a welcome development from an economic perspective. However, this would ideally be phased out as it still poses a significant challenge to cost reflectivity with other

consumer groups (mainly domestic), paying higher amounts to cover for this deficit.

- In order to avoid “passive winners” and avoid revenue shortfalls, metered customers now are required to pay the higher of their metering and rateable value pricing calculations. However, this solution defeats the purpose of charging based on metered consumptions, as it eliminates the incentive to consume less than what they would pay using the rateable value approach. It is unclear whether revenue shortfalls would be created without this stipulation as unmetered customers could also pay more if they were metered and switch to this regime.

4.4 Wastewater tariff design recommendations

Sewer-connected customer charges

As mentioned earlier, metering is not currently a factor for wastewater pricing, with the main distinction made between customers connected to the sewer and those using septic tanks. For users connected to the sewer, billing is based on the rateable value of the property rather than the service utilised. Nonetheless, this results in the same missing incentives and potential for savings that the ones described for water supply.

More widespread water metering could also result in savings from wastewater billing. As recommended in the Pricing Strategy Review of 2018, there is a clear link between the consumption of both services, with 90% of water assumed to become wastewater. This idea has not been rejected by MU with more clarity required on the implementation of such types of charging. A higher availability of such data for different customer categories would facilitate the implementation of this form of wastewater pricing, avoiding the use of proxies and providing customers with incentives to use these services more efficiently.

Trade effluent charges

The treatment of wastewater used in industrial processes involves additional costs to utilities which should be reflected in the charges to these customers. In 2018, a licencing regime for controlling trade effluent was being implemented, where monitoring of the quality of wastewater through sampling was a key component. At the time, the use of the Mogden formula, which is used to determine the chemical oxygen demand and the suspended solid in effluent coming from industrial processes, was proposed to estimate charges for wastewater using the sampling protocols from the licencing regime. This estimation is deemed more accurate than consumption-based measurements as it reflects the additional costs incurred from higher pollutant concentrations in the same volume of wastewater.

Since then, MU has stated that this recommendation may result too complicated for its implementation with no significant gain. In fact, the licencing regime, lower in complexity, remains not fully operational due to staffing constraints. Additionally, it has been mentioned that industrial customers in the Isle of Man already have good wastewater treatment and do not pose a strain to the wastewater system process.

5 Framework for updating tariffs

5.1 Recommendations in the 2018 Pricing Strategy Review

The 2018 Pricing Strategy Review undertaken by ECA made various recommendations that are pertinent to this report. These are summarised below⁴⁷.

- There is a need for the pricing strategy to address the adjustment of charges to take account of divergences between revenues and costs.
- When considering options for updating tariffs, the two charging principles of **cost recovery** and **stability** are most relevant.
- Updates to tariffs can include to:
 - **Review** tariffs through a detailed analysis of forecast costs and customer demand; and
 - **Reset** tariffs through rapid adjustments based on changes in predetermined transparent benchmarks.
- Broadly, the options for updating tariffs include to:
 - Review and reset tariffs annually;
 - Review and reset tariffs every 3-5 years;
 - Review tariffs every 3-5 years, but reset annually according to predetermined factors;
 - Reset tariffs in response to a trigger event

Table 18 compares the merits of each of the options.

⁴⁷ Please read Section 6 of the 2018 Pricing Strategy Review for the full detail of the recommendations.

Table 18 Comparative merits of different tariff updating approaches

	Short-term financial certainty	Short-term stability in level of charges	Certainty over the timing of the tariff	Stability in charges at review	Incentives for efficiency
Review and reset tariffs annually					
Review and reset tariffs every 3-5 years					
Review tariffs every 3-5 years, but reset annually according to a predetermined formula					
Reset tariffs in response to a trigger event					
Key					

Source: ECA

- Fixing tariffs for a period of 3-5 years provides greatest certainty to customers over tariffs in the short to medium term, and by allowing tariffs to change within the period for predefined factors, such as inflation and gas costs, the risk to consumers of large changes in tariffs when they are reset is reduced (as is the financial risk to MU). This option also introduces an added discipline on MU (by only allowing for tariffs to change within the period for factors beyond their control).
- Recommended tariff changes within the period are as follows:
 - To reduce the risk from fluctuations in **gas costs**, ECA proposed that gas costs be passed through in full to revenues, ie, that MU's gas costs are included in revenues to be collected through tariffs.
 - ECA proposed that the risk of inflation forecasts being wrong is removed by indexing the revenues (excluding the gas costs component, which is passed through in full) that MU can recover from tariffs to an appropriate inflation index.

While not included in the 2018 recommendations, we note that the recommendations may be combined. In particular, tariffs may be reset annually within a 3-5 year control period but may also be reset (or reviewed) in response to a 'trigger event', to be defined by MU.

5.2 Updated recommendations for 2024

This section builds on the recommendations from 2018. We note, too, the request to consider “fuel cost price adjustment mechanisms to accommodate the volatility of **gas prices** or increased energy costs due to higher levels of electricity import”. Through discussions with MU, we understand that a portion of the price paid for gas is hedged, ie, not exposed to changing prices. If allowed revenues are not indexed to **inflation** *ex ante*, they can be adjusted *ex post* through similar mechanisms. However, it is important to ensure that only that part of costs not already adjusted through other rebalancing mechanisms, such as those discussed in this section, be adjusted for inflation. Additionally, through discussions with MU, we agreed to consider indexing the **cost of debt**, to the extent that a proportion of MU’s debt has costs that are not fixed⁴⁸.

Inflation can be considered separately from the other two variables as it is, by definition, a change in prices. The Bank of England’s inflation target is 2% over the medium term. Unless inflation is zero, *MU’s prices will almost certainly change*, leaving it exposed to those changes unless they can be passed on to customers. Some inflation can be forecast in prices, in which case it is the variance from forecast inflation that can be adjusted for, rather than the variance in forecast prices. For gas prices and the cost of debt, a certain price must be forecast, and will be passed on to customers, and it is only *changes in those assumed prices* that are likely to leave MU exposed.

The section considers two aspects of the recommendations in further detail:

- The structure of within-period tariff adjustments; and
- The indices to guide within-period adjustments.

The section concludes with simulations of adjustments based on previous years’ data.

5.2.1 Structure of within-period adjustments

The structure of the recommendations in Section 5.1 can be detailed further to determine the:

- Regularity of adjustments; and
- Scale of adjustments.

Regularity of adjustments

The 2018 Pricing Strategy proposed annual tariff adjustments for changes in gas prices. More regular adjustments, ie, quarterly and semi-annually, may also be considered. We consider the regularity of adjustments for each of the three variables.

The **first consideration** to guide this is whether more regular adjustments will be accepted by customers. In Great Britain, while retail prices are unregulated, Ofgem’s price cap is set quarterly, which suggests a degree of acceptability for quarterly adjustments. We see little

⁴⁸ MU has a combination of fixed rate and floating rate borrowing; Manx Utilities’ bonds are fixed as is its refinanced Consolidated Loans Fund borrowings.

marginal benefit in making more regular updates than this. Ultimately, the regularity of adjustments is for MU to decide. In deciding this, we recommend considering staging a transition to more regular adjustments, ie, making annual adjustments for one year, semi-annual adjustments for a second year, before settling on quarterly adjustments after two years.

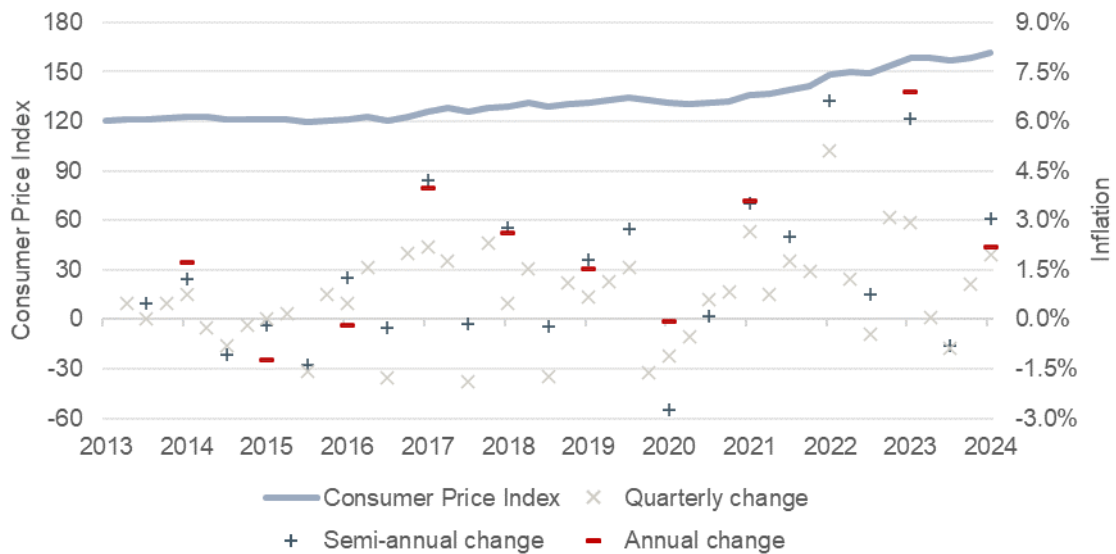
The **second consideration** is the volatility of the cost (and index) against which adjustments will be made, and whether the volatility is predictable, ie, there are no seasonal trends.

Volatility is only important to the extent that the cost is passed through to customers. If a particular cost changes significantly, but only contributes a small percentage of total costs (and impact on tariffs), it may not require within-period adjustment. We have assessed MU's exposure to each of the variables through analysis of its allowed revenue model and in discussions with the company. This allows us to determine the extent to which exogenous volatility in the price (and identified benchmark index) also exposes MU's revenues.

We consider the volatility of the three exogenous variables in turn, noting that gas prices and the cost of borrowing are costs to MU, while inflation is a *change* in costs.

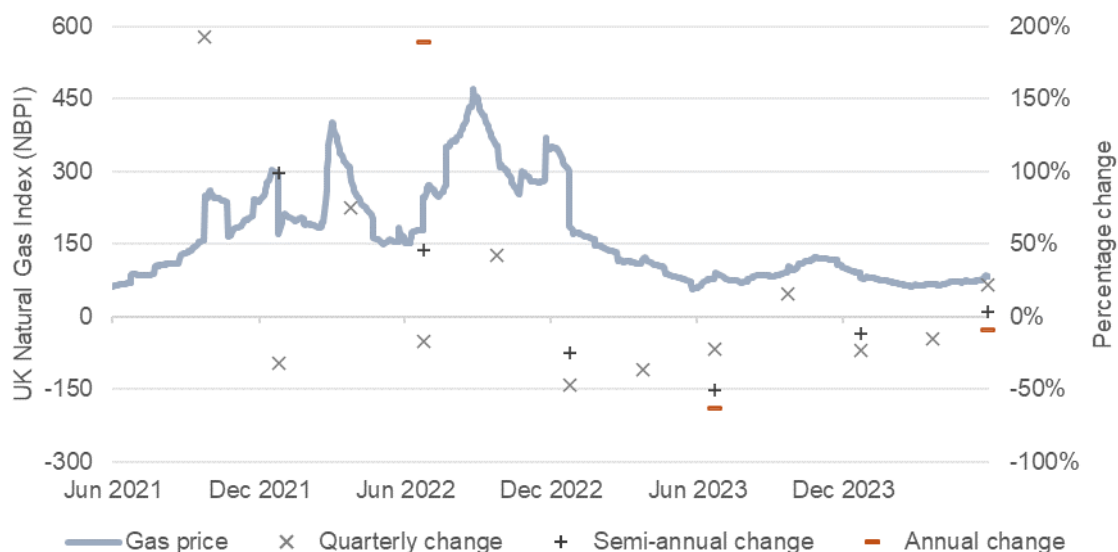
We expect some **inflation**, given the Bank of England's inflation target is 2% in the medium term. Therefore, the question is not whether to pass inflation on to customers, but how often. It may be prudent to factor 2% inflation into MU's allowed revenues at the start of the control period, leaving exposure only to inflation higher or lower than 2%. Furthermore, we would expect that many of MU's costs are subject to inflation, although if changes in the cost of gas and some of the costs of debt are passed through to customers already, an inflation adjustment should only be applied to remaining costs.

Figure 8 suggests that inflation is typically stable on the Isle of Man, where, with the exception of a few outliers in 2022 and 2023, the Consumer Price Index and inflation have seen few large changes over the last ten years. Therefore, the degree to which prices are adjusted for inflation will be somewhat predictable, and the extent to which MU passes this on to customers beyond any forecast inflation will depend on its perception of customers' ability to absorb regular changes (the first consideration above).

Figure 8 Isle of Man inflation since 2013

Source: Statistics Isle of Man, Cabinet Office, May 2024 report

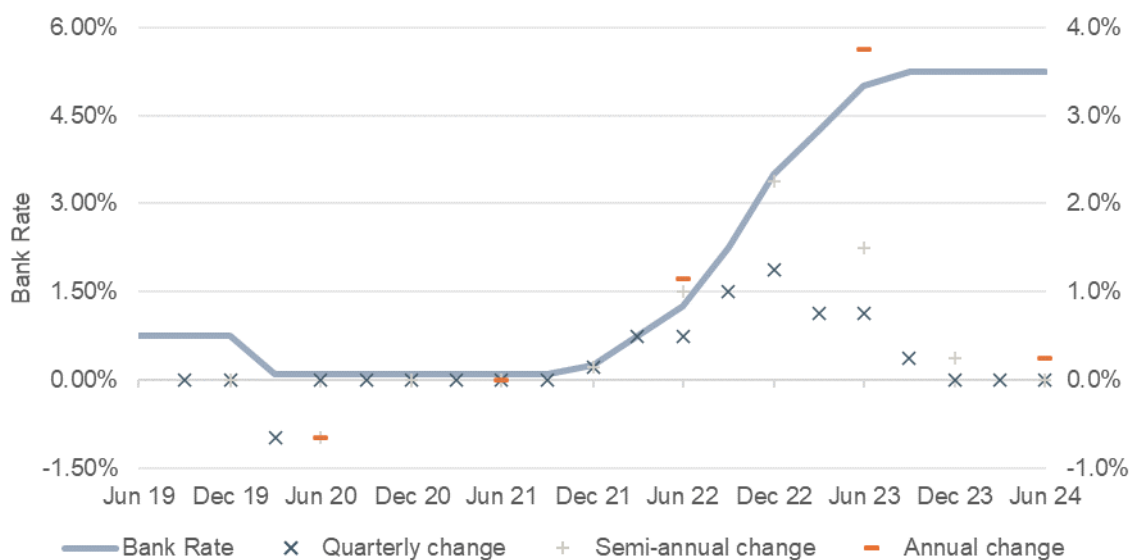
Gas prices, as presented in Figure 9, have been exceptionally volatile in the past few years. While this may be considered exceptional, even the volatility of the past year, where prices have been much more stable, has seen a minimum absolute quarterly change of 16%. Contrastingly, in the past year, the maximum absolute semi-annual change was 12%, while the annual change was a much more stable 9%. While this is just a sample year, it suggests that short-term volatility has the potential to be offset by taking a longer measurement horizon to mitigate the risk of movements in one-quarter being reversed in the following quarter. In addition, one may expect, *a priori*, to see seasonal impacts on gas prices with higher prices in winter than summer, providing further weight to the benefit of measuring changes in gas prices on an annual basis, at least as the default position.

Figure 9 UK gas price trends and volatility

Source: ICE Data Services

Finally, in general, **borrowing costs** are largely tied to the Bank of England's Bank Rate, with changes in commercial lending rates typically mirroring changes in the Bank Rate. Officially, the Bank of England's Monetary Policy Committee meets to set the Bank Rate eight times a year, or approximately every six weeks. From 2010-2021, it was not changed more than once a year, and was unchanged from 5 March 2009 to 4 August 2016. However, in 2022, it was increased eight times, including three increases of 50 basis points and one of 75 basis points. It has remained unchanged since 3 August 2023. The events of 2022 may be considered an anomaly, given global market conditions. Figure 10 shows the Bank Rate over the last five years, with quarterly, semi-annual, and annual changes in basis points (based on the rates in place at the end of each quarter, half-year, or year). The figure shows that, on the whole, with the exception of the period from late 2021 until mid-2023, rates have been stable, and changes, when they have been announced, have been relatively minor, at least when compared with gas prices.

Figure 10 Bank of England Bank Rate



Source: Bank of England; changes are in basis points

Of the two cost variables considered, borrowing costs are typically very stable without clear seasonal trends, while gas prices are considerably more volatile. Additionally, borrowing costs tend to move consistently in the same direction over a period before levelling off, while gas price changes can reverse direction multiple times within a year. While this may suggest that MU is more exposed to changes in gas prices than changes in borrowing costs, and should minimise its exposure to these by making more regular changes to the former and less regular changes to the latter, we believe this would lead to tariffs that are highly volatile and very difficult for customers to manage. Rather, we recommend the opposite because of the drive to keep customer tariffs stable. By incorporating the anticipated small changes to tariffs from inflation and changes in borrowing costs on a quarterly basis, MU will mitigate its exposure without creating undue volatility in customer tariffs.

MU should consider making quarterly changes to tariffs to incorporate unanticipated inflation and reflect changes in borrowing costs, and annual changes to tariffs to reflect changes in gas prices.

Scale of adjustments

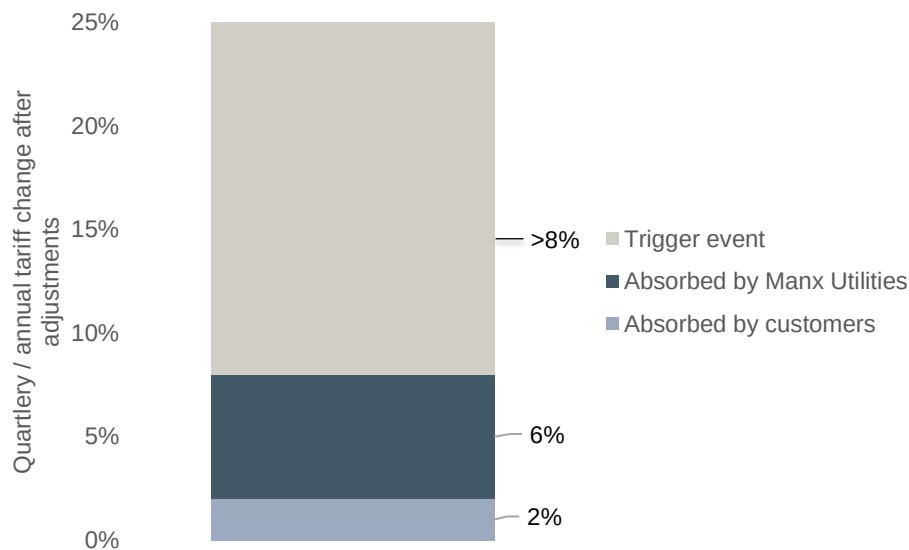
Having determined which variables should be monitored during a price control (inflation, gas prices, and the cost of borrowing), MU must also decide how much of its exposure it should pass through to customers and how much should be recovered through an end-of-period 'true-up' or 'claw-back'. Such an end-of-period mechanism calculates any shortfall (or surplus) from forecast revenues at the end of the period and adjusts the allowed revenues for the following period to ensure it is balanced off and the utility is made good, at least for that previous period's shortfall/surplus. As with the regularity of adjustments, MU should also determine the scale of adjustment based on its understanding of the willingness and ability of customers to bear tariff adjustments on a quarterly (inflation, cost of borrowing) or annual (gas prices) basis.

We propose MU adopts the same thresholds for each quarterly adjustment (first, second, third quarters), and different thresholds for the annual adjustment. The thresholds to consider would be based on percentage changes in the prevailing tariff once all cost adjustments have been considered, and are as follows:

- First threshold: how much customers can absorb. The next amount beyond this will be absorbed by MU (until the end of the period 'true-up').
- Second threshold: for amounts beyond the first threshold, how much MU can absorb (to then be incorporated in an end-of-period 'true-up'). Amounts beyond this may constitute a 'trigger event' and lead to a tariff review.

Figure 11 presents an example of how these different thresholds could be applied at a quarterly or annual review. In this example, once all automatic adjustments have been calculated, MU will determine the change in the prevailing tariff. Any potential tariff change after the adjustment of up to 2% would be passed through to and absorbed by the customer. For any change greater than 2%, the first 2% would be absorbed by the customer, and the next 6% would be absorbed by MU. Any change greater than 8% would be considered a criterion for a trigger event to initiate a full tariff review. As a full tariff review is a significant undertaking, and large changes in the variables may not be sustained from one-quarter to the next, MU may consider a higher threshold than simply crossing the 8% threshold in a single quarter. For example, a trigger event may only be possible at the end of each full year of the price control, wherein the previous two-quarters (mid-year and third quarter) had also seen the trigger event threshold breached.

Figure 11 Absorption of tariff changes at automatic quarterly/annual adjustments



Source: ECA

5.2.2 Indices and methodology to guide within-period adjustments

We have identified three variables for within-period adjustments. In this section, we consider how MU may determine changes to its costs and make adjustments to tariffs. Any adjustments must be transparent and robust, with predetermined formulae and guidance for customers, in such a way that customers are not surprised by them. Nominating a well-understood index and publishing adjustment formulae will support MU's ability to make the adjustments in a way that is beyond reproach.

- **Statistics Isle of Man's Consumer Prices Index (CPI)** is published monthly. This is likely to be a more accurate reflection of consumer prices for Manx Utilities' customers than any index from Great Britain. The CPI includes electricity, but as MU's tariffs are not currently adjusted for inflation⁴⁹, it does not make sense for them to be included in the CPI. Therefore, we propose that CPI be used for inflating all costs except gas prices and borrowing costs that are not fixed. If it can be argued that other costs already include inflation adjustments, they may also be excluded.
- MU's gas prices may already be pegged to an international benchmark index. If so, the same index should be used for the proposed annual gas price adjustments. If not, we recommend an index such as the **UK Natural Gas Index (NBPI)**, published by a reputable source such as ICE Data Services.
- Some of MU's long-term borrowing is subject to interest rate variability. We would assume that any adjustments to interest rates are pegged to a transparent index in the same way as is being proposed for its tariffs. We therefore recommend **using the same index** for its tariff adjustments.

⁴⁹ If this is incorrect, we will consider how to adjust the approach.

We make the following additional comments regarding the methodology for making adjustments:

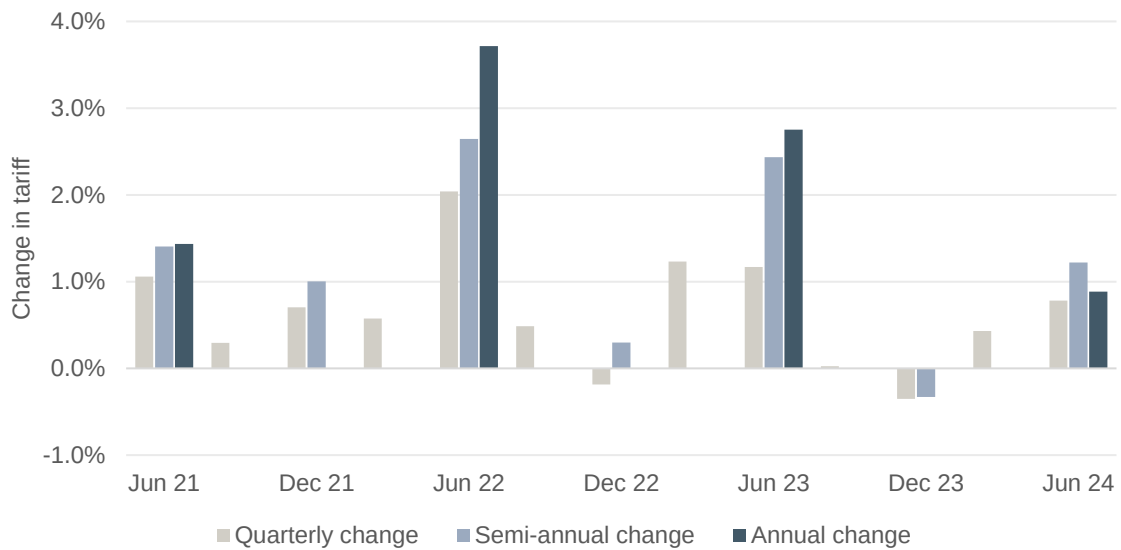
- Adjustments will need to be made in arrears to allow time for data publication, eg, make a change on 1 April using CPI data from the end of January. This is particularly so for the CPI. MU should set a date at which each index is measured and beyond which each estimate is unlikely to be challenged. It should then allow sufficient time to determine the changes in each index and work out how they should be applied to allowed costs, before publishing forecast tariff changes with sufficient warning for customers.
- Only adjust those costs that are exposed. As already noted, inflation adjustments should only be made on costs other than gas prices and borrowing costs (and any other costs not subject to inflation, ie, fixed in contracts). We understand that MU already hedges around 50% of its gas price, leaving 50% exposed to price volatility; only this remaining 50% should be adjusted. Similarly for borrowing costs, only a portion of long-term borrowing is exposed to rate fluctuations, so only that portion of interest costs should be adjusted in the required revenues.

5.2.3 Simulation of within-period adjustments

For illustrative purposes, the following figures take real data and suggest the impact on tariffs that changes in selected variables could have. We note that each is taken individually (not a combination of inflation, gas price changes, and changes in borrowing costs) and has not yet been applied in full to MU's actual data.

Firstly, Figure 12 shows the impact that inflation may have on tariffs. As noted above, inflation adjustments would only be applied to that portion of allowed revenues not already subject to an adjustment or already fixed by some other arrangement. Inflation forecasts may already be incorporated into allowed revenues, in which case the impact should be based on the variance from forecast inflation. We have assumed that 40% of MU's costs would be affected, and that inflation is not already factored into costs, therefore multiplying inflation by 0.4 to get the impact on the whole tariff.

Figure 12 Potential impact of inflation on tariffs

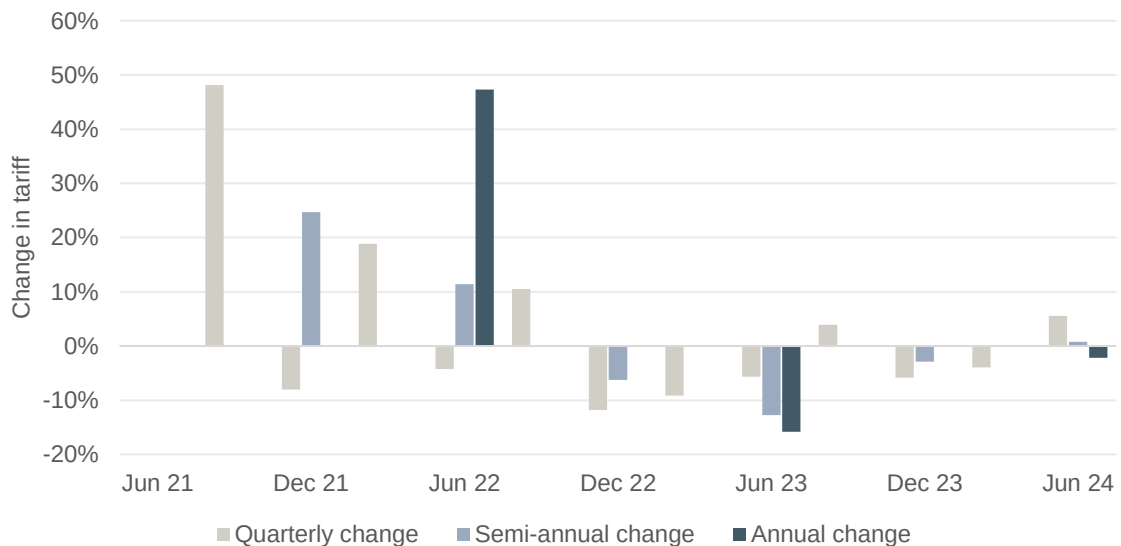


Source: ECA, adjusted from Statistics Isle of Man, Cabinet Office, May 2024 report

The figure shows that only in one-quarter, June 2022, would inflation have led to a tariff increase of more than 2.0%, and at no point would it have led to a trigger event.

Secondly, Figure 13 considers changes in gas prices.

Figure 13 Potential impact of changes in gas prices on tariffs



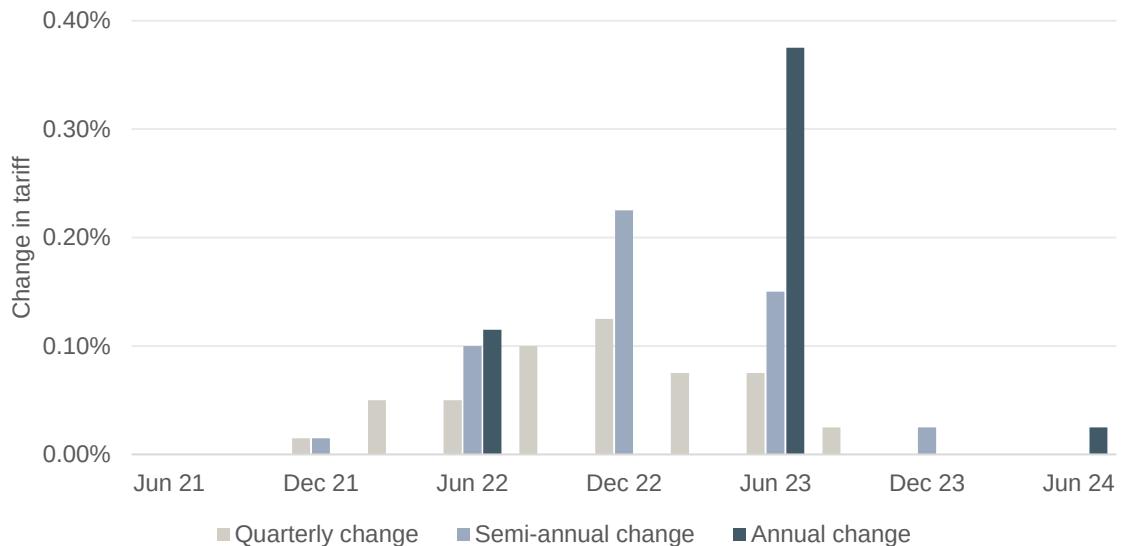
Source: ECA, adjusted from ICE Data Services

Based on our methodology, we see annual changes in tariffs from gas price changes of more than 8% in June 2022 and June 2023 which could be considered trigger events. However, in neither case were the changes large enough in both preceding quarters to also be considered trigger events (December 2021 is exactly -8%, so very nearly large enough). This would have

seen customers absorb changes of only 2% annually⁵⁰ and MU absorb the remainder until the next potential trigger event or full tariff review, whichever came sooner.

Finally, our simulation of borrowing costs that are not fixed assumes that 10% of any change in borrowing costs is passed through to customers, as shown in Figure 14.

Figure 14 Potential impact of changes in borrowing costs on tariffs



Source: ECA, adjusted from Bank of England

These data show that, based on our assumptions, quarterly changes in borrowing costs are minimal and should be fairly easily absorbed by customers while also giving some leeway to changes in other costs, without the need for MU to absorb additional costs until the end of the period or a trigger event, whichever is sooner.

⁵⁰ Here, for illustrative purposes, we are applying the same 2% threshold for annual reviews that include gas prices as was applied for quarterly reviews of inflation and borrowing costs.