# United Energy 2018 Pricing Proposal

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# Executive summary

This Pricing Proposal addresses the obligations specified in the Electricity Distribution Price Review (EDPR) where United Energy (UE) is required to make an annual submission to the AER outlining;

- Electricity distribution (DUoS), transmission use of system (TUoS) and jurisdictional/pass through charges
- Rates for standard control and alternative control services
- Tariff eligibility criteria
- Customer impact of new tariffs versus prior year
- Pricing principles and tariff strategy
- Customer/stakeholder engagement process

In developing this Annual Tariff Report, UE has aligned with the strategies tabled in our revised Tariff Structure Statement (TSS) submitted to the AER in September this year. A key feature of the TSS was the articulation of a targeted consultation program with key stakeholder groups, the results of which have informed our future tariff strategies.

UE's revised TSS was submitted to the AER on the 5th of September 2017. The amended TSS incorporated changes to the AMI Tariffs Order subsequently published in the Victorian Government Gazette 12th September 2017, requiring UE to provide a non-demand based tariff option for business customers (consuming 40-160MWh per annum) on an "opt-out" basis. Details of this change to tariff eligibility requirements are described in section 4.3.2.

Under the price control formula the average DUoS movement is calculated to be an increase of 5.2% on the 2017 rates. United Energy acts as an agent for the recovery of grid fees levied by transmission operators. Recovery of grid fees is levied in the form of TUoS. Previous years under/over recovery and decreases in grid fees for the 2017/18 financial year have driven an average TUoS tariff decrease of 15.2% compared to 2017. The combined effect of these changes delivers an overall NUoS increase for 2018 of 0.6%.

A summary of the annual movement in DUoS and TUoS appears below. When combined with price movements in jurisdictional and pass through charges (PFIT recovery, AMI meter charges), the average residential customer on a single rate tariff will see an annual network use of system (NUoS) decrease of $8.89 over the 2017 charges. Eligible residential customers have the potential to participate in further savings by transitioning to the residential demand tariff (RESKW1R) during 2018.

Unless otherwise stated, the tariffs proposed in this submission are intended to apply for the period 1st January 2018 to 31st December 2018 and are subject to endorsement by the AER. A response from the AER is anticipated in October/November 2017.

**UED Indicative 2018 Tariff Price Movements**

| Description | Tariff Code | DUOS % price movement | TUOS % price movement | NUOS % price movement |
|---|---|---|---|---|
| **Class - Low Voltage Small** | | | | |
| Low voltage small 1 rate | LVS1R | 3.2% | -15.2% | -0.7% |
| Dedicated circuit | LVDed | 3.2% | | 3.2% |
| Low Voltage KW 1 rate (opt-in) | RESKW1R | 3.2% | -15.2% | -0.8% |
| **Class - Low Voltage Medium** | | | | |
| Low voltage medium 1 rate | LVM1R | 6.1% | -15.2% | 1.5% |
| Low voltage medium 2 rate 5 day | LVM2R5D | 6.1% | -15.2% | 2.9% |
| Low voltage medium 2 rate 7 day | LVM2R7D | 6.1% | -15.2% | 2.1% |
| Low voltage KW time of use | LVkWTOU | 6.1% | -15.2% | 2.3% |
| Time Of Use | TOU | 6.1% | -15.2% | 2.8% |
| Low voltage medium KW time of use (opt-in) | LVMKWTOU | 6.1% | -15.2% | 1.7% |
| Low voltage medium KW 1 rate (mandatory) | LVMKW1R | 6.1% | -15.2% | 1.8% |
| **Class - Low Voltage Large** | | | | |
| Low voltage large 2 rate | LVL2R | 7.8% | -15.2% | 4.3% |
| Low voltage large 1 rate | LVL1R | 7.8% | -15.2% | 1.0% |
| Low voltage large KVA time of use | LVkVATOU | 7.8% | -15.2% | 1.9% |
| **Class - High Voltage Large** | | | | |
| High voltage KVA time of use | HVkVATOU | 7.2% | -15.2% | -0.2% |
| **Class - Subtransmission Large** | | | | |
| Subtransmission KVA time of use | SubTkVATOU | 7.2% | -15.2% | -7.0% |
| **Total** | | **5.2%** | **-15.2%** | **0.6%** |

# 1. Introduction and structure

United Energy (UE) is one of five electricity distribution businesses operating under licence within the State of Victoria. UE manages and operates an extensive urban and semi-rural electricity distribution network with a replacement value of over $4 billion, comprising 47 zone substations, approximately 216,000 poles, 13,000 distribution substations, 10,000 km of overhead power lines and 2,834 km of underground cables. UE's electricity distribution network provides services to some 673,000 end-use customers, located in an area of 1,472 km$^2$ in south-east Melbourne and the Mornington Peninsula. UE's distribution area is shown below:

**Figure 1-1: UE Distribution Territory**


This document is UE's 2018 Pricing Proposal to the Australian Energy Regulator (AER). In accordance with the requirements of the National Electricity Rules (Rules), clause 6.18.2(b) requires that a Pricing Proposal must:

(a) set out the proposed tariffs for each *tariff class*

(b) set out, for each proposed tariff, the *charging parameters* and the elements of service to which each *charging parameter* relates;

(c) set out, for each *tariff class* related to *standard control services*, the expected weighted average revenue for the relevant *regulatory year* and also for the current *regulatory year*;

(d) set out the nature of any variation or adjustment to the tariff that could occur during the course of the *regulatory year* and the basis on which it could occur;

(e) set out how *designated pricing proposal charges* are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those charges in the previous *regulatory year*;

(f) set out how *jurisdictional scheme amounts* for each *approved jurisdictional scheme* are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those amounts;

(g) describe how each *approved jurisdictional scheme* that has been amended since the *last jurisdictional scheme approval date* meets the *jurisdictional scheme eligibility criteria*;

(h) demonstrate compliance with the *Rules* and any applicable distribution determination, including the *Distribution Network Service Provider's tariff structure statement* for the relevant *regulatory control period*;

(i) demonstrate how each proposed tariff is consistent with the corresponding indicative pricing levels for the relevant *regulatory year* as set out in the relevant *indicative pricing schedule*, or explain any material differences between them; and

(j) describe the nature and extent of change from the previous *regulatory year* and demonstrate that the changes comply with the *Rules* and any applicable distribution determination.

In addition to the above provisions:

- clause 6.18.3 sets out requirements in relation to the definition of tariff classes;
- clause 6.18.4 sets out principles for the reassignment of customers to tariff classes;
- clause 6.18.5 describes the pricing principles that must apply to tariff classes;
- clause 6.18.6 provides for a side constraint on tariffs for standard control services;
- clause 6.18.7 defines the arrangements for the recovery of charges for transmission use of system;
- clause 6.18.8 sets out the arrangements for approving the Pricing Proposal; and
- clause 6.18.9 sets out provisions regarding the website publication of pricing information prior to the commencement of the regulatory year.

This Pricing Proposal takes account of the AER's final decision[1] on United Energy's distribution determination for the period 2016-2020. The remainder of this Pricing Proposal is structured as follows;

- Section 2 identifies the pricing issues arising from the AER's final decision[1];
- Section 3 sets out UE's proposed tariff classes and charging parameters;
- Section 4 describes UE's tariff strategy and the application of the pricing principles in the Rules;
- Section 5 sets out UE's proposed standard control tariffs for 2018 and the average charges to customers;
- Section 6 demonstrates that UE's proposed tariffs for 2018 comply with the Rules and the AER's final determination;
- Section 7 provides information in relation to the transmission component in the network tariffs;

[1] Issued by AER 26 May 2016.

- Section 8 provides details of UE's approach to tariff assignment and reassignment;
- Section 9 sets out information in relation to UE's alternative control services;
- Section 10 sets out information in relation to UE's alternative control services – metering services;
- Section 11 sets out information in relation to UE's public lighting charges; and
- The appendices provide details of UE's proposed tariffs for 2018 and indicative tariffs for 2019 & 2020;

In summary, this Pricing Proposal demonstrates compliance with the Rules and also provides information to assist stakeholders regarding the issues, principles and rationale that have shaped UE's approach to setting its network tariffs for 2018. UE welcomes comments from interested parties as UE continually evolves its approach to tariff and price setting.

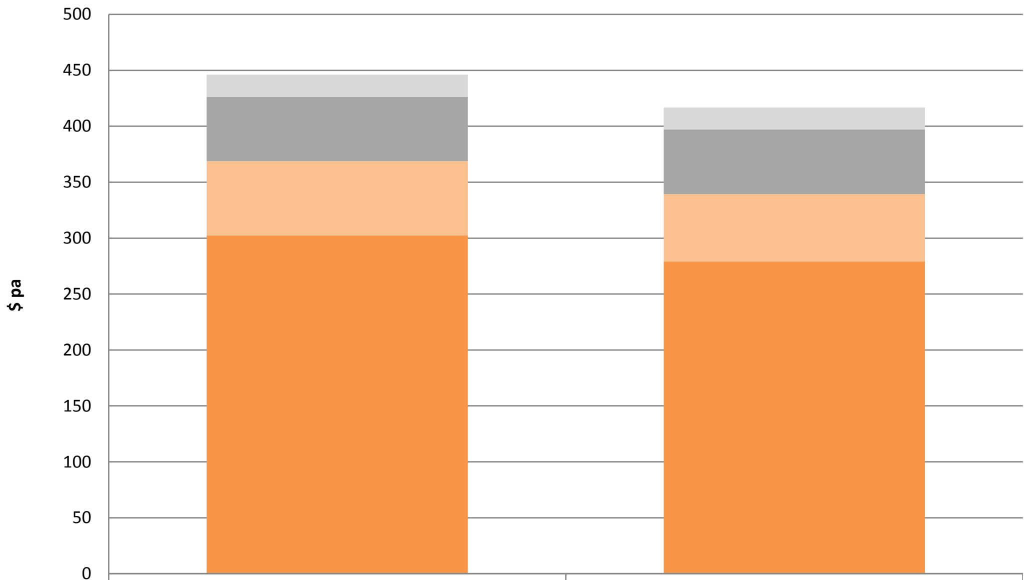
## 1.1. UE's average charge for small residential customers

For 2018 the average UE network tariff bill for residential customers will be comprised of four components; Distribution Use of System (DUoS), Transmission Use of System (TUoS), Advanced Interval Metering (AMI) and Solar Feed in Tariff schemes (PFIT).

The average residential customer without electric hot water consumes approximately 4.2MWh per annum. The composition of the network charge is approximately 68% DUOS, 15% TUOS, 13% AMI and 4% PFIT.

Figure 1-2 below displays the 2018 average network charge for the common residential tariff (LVS1R) compared to the UE residential demand tariff alternative (RESKW1R).

**Figure 1-2: 2018 Indicative network charge for a residential customer (4200kWh pa)**




| | LVS1R | RESKW1R |
|---|---|---|
| PFIT/TFIT | 19.74 | 19.74 |
| AMI | 57.58 | 57.58 |
| TUOS | 66.25 | 60.08 |
| DUOS | 302.54 | 279.30 |

Further details relating to residential/small customers average charges can be found in section 5.3.1.

# 2. Pricing impacts arising from the AER's final decision on United Energy's distribution determination

## 2.1. UE's expected revenues for standard control services and X factors

As per the AER's updated version of the final decision SCS PTRM setting out the annual update[2], UE's revenue requirements and X factors are set out below.

**Table 2-1: AER re-determination–revenues and X factors**

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Expected Revenues ($'m, nominal) | 375.07 | 398.48 | 420.61 | 445.44 | 455.79 |
| AER's CPI estimate | 1.50% | 1.02% | 1.93% | 2.32% | 2.32% |
| X factor* | 8.56% | -3.83% | -3.16% | -3.50% | 0.00% |

*Positive values for X indicate real price decreases

## 2.2. Revenue cap formula

As part of the Pricing Proposal, UE must submit to the AER proposed tariffs and charging parameters which correspond to the price terms contained in the total annual revenue formulae and side constraint equations.

The Revenue Cap formulae to apply to the Victorian DNSPs for the forthcoming regulatory control period is:

(1) $TAR_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_t^{ij} q_t^{ij}$ i=1,..,n and j=1,..,m and t=1,..,5

(2) $TAR_t = AAR_t + I_t + T_t + B_t$ t = 1,2,…,5

(3) $AAR_t = AR_t(1+S_t)$ t = 1

(4) $AAR_t = AAR_{t-1}(1+\Delta CPI_t)(1-X_t)(1+S_t)$ t = 2,…,5

where;

$TAR_t$ is the total annual revenue in year t.

$p_t^{ij}$ is the price of component 'j' of tariff 'i' in year t.

[2] Dated 8th September 2017.

$q_t^{ij}$ is the forecast quantity of component 'j' of tariff 'i' in year t.

$AAR_t$ is the adjusted annual smoothed revenue requirement for year t.

$I_t$ is the annual adjustment f–factor scheme amount in year t. This amount will be calculated as per the method set out in the relevant f–factor scheme.

$T_t$ is the final carryover amount from the application of the DMIS from the 2011–15 regulatory control period. This amount will be calculated using the method set out in the DMIS and will be deducted from/added to allowed revenue in the 2018 pricing proposal.

$B_t$ is the sum of:

- the recovery of license fee charges by the Victorian Essential Services Commission indexed by one and a half years of interest, calculated using the following method:

  $$L_{t-1} \times (1+WACC_t)(1+WACC_{t-1})^{1/2}$$

  where:

  $L_{t-1}$ are the licence fees paid by United Energy to the Victorian Essential Services Commission in the financial year ending in June of regulatory year t–1,

  $WACC$ is the approved nominal weighted average cost of capital (WACC ) for the relevant regulatory year using the following method:

  $$Nominal\ vanilla\ WACC_t = ((1+real\ Vanilla\ WACC_t)\times(1+\Delta CPI_t))-1$$

  where the $real\ Vanilla\ WACC_t$ is as set out in AER's final decision PTRM and updated annually

- any under or over recovery of actual revenue collected through DUoS charges in regulatory year t–2 as calculated using the method outlined in AER's final decision 26th May 2016 (Appendix A of Attachment 14).
- the AER approved pass through amounts (positive or negative) with respect to regulatory year t.

$AR_t$ is the annual smoothed revenue requirement as stated in the Post Tax Revenue Model (PTRM) for year t (when year t is the first year of the 2016–20 regulatory control period).[3]

$S_t$ is the s-factor determined in accordance with the service target performance incentive scheme (STPIS) for regulatory year t.[4]

$\Delta CPI_t$ is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[5] from the June quarter in year t–2 to the June quarter in year t–1, calculated using the following method:

The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the June quarter in regulatory year t–1

[3] AER states that if necessary an adjustment for inflation may be required to the annual smoothed revenue requirement for year t. However, as the annual smoothed revenue requirement for year t as stated in AER's final decision PTRM is in nominal dollars there is no need to adjust it for inflation. This approach is consistent with past regulatory practice.

[4] For the first two years of the 2016–20 regulatory control period, the value of $S_t$ is to be adjusted to account for the change in revenue requirements between the regulatory control periods, as explained in attachment 11 in AER's final determination. In the formulas in the STPIS, the $AR_{(t+1)}$ is equivalent to $AR_t$ in this formula. Calculations of the S factor adjustment are to be made accordingly.

[5] If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the AER considers is the best estimate available of the index alternative index.

divided by
The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the June quarter in regulatory year t–2 minus one.

For example, for the 2018 regulatory year, t–2 is June quarter 2016 and t–1 is June quarter 2017 and for the 2019 regulatory year, t–2 is June quarter 2017 and t–1 is June quarter 2018 and so on.

$X_t$ is the X factor for each year of the 2016–20 regulatory control period as determined in the PTRM, and annually revised for the return on debt update in accordance with the formula specified in attachment 3 in AER's final decision —rate of return—calculated for the relevant regulatory year.

## 2.3. Side constraint formula

The side constraints formula to apply to the Victorian DNSPs for the 2016-20 regulatory control period is set out below. Noting that for each year after the first year of a regulatory control period, side constraints will apply to the weighted average revenue to be raised from each tariff class.

Where for each tariff class a DNSP has *n* distribution tariffs, which each have up to *m* distribution tariff components:

$$\frac{(\sum_{i=1}^{n}\sum_{j=1}^{m} d_t^{ij} q_t^{ij})}{(\sum_{i=1}^{n}\sum_{j=1}^{m} d_{t-1}^{ij} q_t^{ij})} \leq (1+\Delta CPI_t)\times(1-X_t)\times(1+2\%)\times(1+S_t)+I_t^{'}+T_t^{'}+B_t^{'}$$

- $d_t^{ij}$ is the proposed price for component 'j' of tariff 'i' for year t.
- $d_{t-1}^{ij}$ is the price charged for component 'j' of tariff 'i' in year t–1.
- $q_t^{ij}$ is the forecast quantity of component 'j' of tariff 'i' in year t.
- $\Delta CPI_t$ is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[6] from the June quarter in year t–2 to the June quarter in year t–1, calculated using the following method :

  *The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the June quarter in regulatory year t–1*
  *divided by*
  *The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the June quarter in regulatory year t–2*
  *minus one.*

  For example, for the 2018 regulatory year, t–2 is June quarter 2016 and t–1 is June quarter 2017 and for the 2019 regulatory year, t–2 is June quarter 2017 and t–1 is June quarter 2018 and so on.

[6] If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the AER considers is the best estimate available of the index alternative index.

- $X_t$ is the X factor for each year of the 2016–20 regulatory control period as determined in the PTRM, and annually revised for the return on debt update in accordance with the formula specified in attachment 3—rate of return—calculated for the relevant year. If X>0, then X will be set equal to zero for the purposes of the side constraint formula.
- $S_t$ is the annual percentage change from the STPIS factor as determined in accordance with the STPIS in regulatory year t.[7]
- $I_t^{'}$ is the annual percentage change from the f–factor scheme amount in year t. This amount will be calculated as per the method set out in the relevant f–factor scheme.
- $T_t^{'}$ is the annual percentage change from the final carryover amount from the application of the DMIS from the 2011–15 regulatory control period. This amount will be calculated using the method set out in the DMIS and will be deducted from/added to allowed revenue in the 2018 pricing proposal.
- $B_t^{'}$ is annual percentage change from the sum of:
- the recovery of license fee charges by the Victorian Essential Services Commission indexed by one and a half years of interest, calculated using the following method:

$$L_{t-1} \times (1 + WACC_t) \times (1 + WACC_{t-1})^{1/2}$$

- where:

  $L_{t-1}$ are the licence fees paid by United Energy to the Victorian Essential Services Commission in the financial year ending in June of regulatory year t–1,
  $WACC$ is the approved nominal weighted average cost of capital (WACC ) for the relevant regulatory year using the following method:

$$Nominal\ vanilla\ WACC_t = ((1 + real\ Vanilla\ WACC_t) \times (1 + \Delta CPI_t)) - 1$$

  where the $real\ Vanilla\ WACC_t$ is as set out in AER's final decision PTRM and updated annually

- any under or over recovery of actual revenue collected through DUoS charges in regulatory year t–2 as calculated using the B factor described in section 2.2.
- the AER approved pass through amounts (positive or negative) with respect to regulatory year t.

With the exception of the CPI, X factor and S factor, the percentage for each of the other factors above can be calculated by dividing the incremental revenues (as used in the total annual revenue formula) for each factor by the expected revenues for regulatory year t–1 (based on the prices in year t–1 multiplied by the forecast quantities for year t).

[7] For the first two years of the 2016–20 regulatory control period, the value of $S_t$ is to be adjusted to account for the change in revenue requirements between the regulatory control periods, as explained in attachment 11. In the formulas in the STPIS, the $AR_{(t+1)}$ is equivalent to $AR_t$ in this formula. Calculations of the S factor adjustment are to be made accordingly.

## 2.4. Tariff class assignment and reassignment procedures

The AER determines the principles governing assignment or reassignment of retail customers (customers) to or between tariff classes.[8] The principles that United Energy is to adhere to in assigning and reassigning customers to tariff classes is outlined below.[9]

UE must take into account one or more of the following factors:

- the nature and extent of the customer's usage;
- the nature of the customer's connection to the network; and
- whether remotely-read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement.

In addition to these requirements, when assigning or reassigning a customer to a tariff class, UE must ensure the following:

- that customers with similar connection and usage profiles are treated equally
- that customers who have micro–generation facilities are not treated less favourably than customers with similar load profiles without such facilities.

In addition to these guiding principles, the AER's procedures for tariff assignment and reassignment:

- describe the arrangements that DNSPs must adopt to notify their customers of a tariff assignment or reassignment, and to address a customer's objections;
- require the DNSP's Pricing Proposal to describe its system for assessing and reviewing the basis on which a customer is charged; and
- confirms that if a DNSP installs an interval meter for an existing distribution customer, the DNSP may reassign that distribution customer to a time of use distribution tariff subject to clause 9.1.14 of the Victorian Electricity Distribution Code.

In this Pricing Proposal, UE confirms that it will comply fully with the AER's procedures for assigning and reassigning customers to tariff classes as set out in Attachment 14 - Control Mechanism Appendix D of the AER's final decision. Further details of UE's approach to tariff assignment and reassignment are provided in section 8 of this Pricing Proposal.

[8] NER, cl. 6.12.1(17).

[9] NER, cl. 6.18.4.

## 2.5. Recovering the cost of Transmission/Grid fees

As shown by table 2-2 and Figure 2-1 below, grid fees vary from year to year.

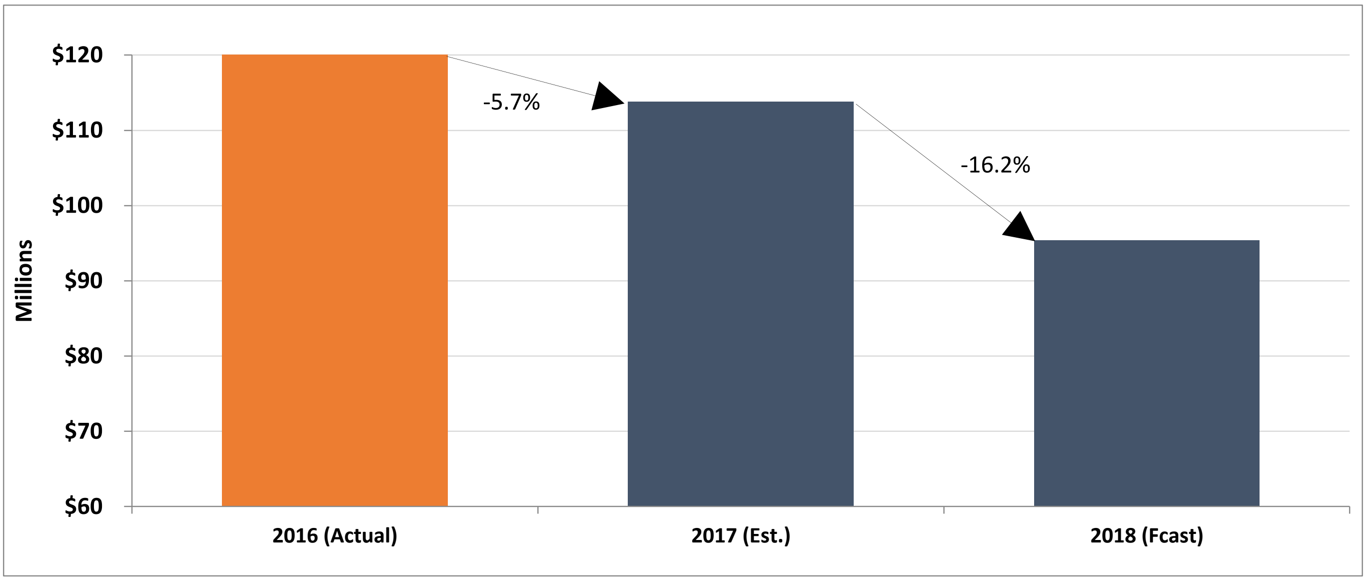
The expected TUOS revenue decrease from 2017 to 2018 is 16.2%. This decrease is primarily driven by the following factors:

- Over-recovery from 2016 and 2017 compared to forecast revenue
- Reduction in Grid fees relative to 2016 & 2017 forecast

**Table 2-2: Estimated TUOS Revenue Increase ($'m)**

| | 2017 (Est) | 2018 (FC) | Var(%) |
|---|---|---|---|
| Grid Fee Forecast | $108 | $108 | |
| Over(under) recovery from previous year | -$6 | $13 | |
| Actual/Allowed Revenue current year (grid fees less over recovery) | $114 | $95 | |
| Estimated Revenue collected | $114 | $95 | -16.2% |

**Figure 2-1: TUoS revenue 2016-2018 ($'m)**



# 3. Tariff classes and charging parameters

## 3.1. Regulatory requirements

This section addresses the Rules requirements in relation to tariff classes. In particular, it provides the following information:

- the tariff classes that are to apply for 2018, in accordance with clause 6.18.2(b)(1);
- the proposed tariffs for each tariff class, in accordance with clause 6.18.2(b)(2); and
- for each proposed tariff, the charging parameters and the elements of service to which each charging parameter relates, in accordance with clause 6.18.2(b)(3); and
- the tariff classes into which customers for direct control services are divided, in accordance with clause 6.18.3, noting that:
    - Separate *tariff classes* must be constituted for customers to whom *standard control services* are supplied and customers to who *alternative control services* are supplied (but a customer for both *standard control services* and *alternative control services* may be a member of 2 or more *tariff classes*).
    - A *tariff class* must be constituted with regard to:

1. the need to group customers together on an economically efficient basis; and
2. the need to avoid unnecessary transaction costs.

## 3.2. Service classification

Before addressing the provisions outlined in section 3.1 above, to assist stakeholders' understanding of the Rules requirements it is useful to summarise the AER's final determination for UE's classification of services into Standard Control Services, Alternative Control Services; Negotiated Services; and Unregulated Services.

#### 3.2.1. Standard control services - Network services

The following services are provided within this classification.

- Constructing the distribution network
- Maintaining the distribution network and connection assets
- Operating the distribution network and connection assets (for DNSP purposes)
- Designing the distribution network
- Planning the distribution network
- Emergency response
- Administrative support (for example, call centre, network billing)
- Location of underground cables

#### 3.2.2. Standard control services - Connection services

The following services are provided within this classification.

- New connections requiring augmentations

#### 3.2.3. Alternative control services - Fee based services

The following services are provided within this classification.

- Fault response (not DNSP fault)
- De-energisation of existing connections
- Re-energisation of existing connections
- Meter investigation
- Special meter reading
- Remote AMI services
- Temporary disconnect / reconnect services
- Wasted attendance (not DNSP fault)
- Service truck visits
- Fault level compliance service
- Photovoltaic installation
- Routine connections (customers below 100 amps)
- Temporary supply services

#### 3.2.4. Alternative control services - Quoted services

The following services are provided within this classification.

- Rearrangement of network assets at customer request, excluding alteration and relocation of existing public lighting assets
- Supply enhancement at customer request
- Emergency recoverable works (that is, emergency works where customer is at fault and immediate action needs to be taken by the DNSP)
- Auditing of design and construction
- Specification and design enquiry fees
- Elective underground service where an existing overhead service exists
- Covering of low voltage mains for safety reasons
- Damage to overhead service cables caused by high load vehicles
- High load escorts (lifting overhead lines)

- Routine connections (customers above 100 amps)
- Supply abolishment
- Reserve feeder
- After hours truck by appointment.

#### 3.2.5. Alternative control services - Public lighting services – fee based

The following services are provided within this classification.

- Operation, repair, replacement and maintenance of DNSP public lighting assets

#### 3.2.6. Alternative control services - Metering services – fee based

The following services are provided within this classification.

- Metering charges (AMI)
- Metering charges public lighting
- Exit fees for transition to competitively sourced meter

#### 3.2.7. Negotiated services

The following services are provided within this classification.

- Alteration and relocation of DNSP public lighting assets
- New public lighting assets (that is, new lighting types not subject to a regulated charge and new public lighting at green field sites)

#### 3.2.8. Unregulated services

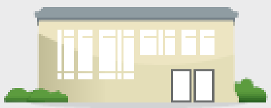
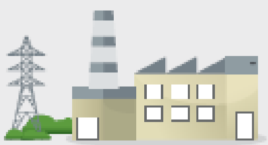
The following services are provided within this classification.

- The installation, maintenance and provision and repair of watchman (security) lights
- Provision of possum guards.
- Pole rental

It should be noted that Section 9 of this Pricing Proposal outlines the arrangements for UE's alternative control metering service tariffs, which in accordance with clause 6.18.3(c) of the Rules has been constituted as a separate tariff class with separate charging parameters.  The remainder of this section 3 addresses the Rules tariff class requirements in relation to the standard control services.

## 3.3. Standard control service tariff classes

UE has established five tariff classes for standard control services as follows:

| | Tariff Class | Typical Customer | Tariff Name | Criteria | Voltage |
|---|---|---|---|---|---|
|  | Low Voltage Small | Residential | Low Voltage Small One Rate (LVS1R) | <20 MWh annual energy usage | 230 Volts |
| | | The typical customer may also have a dedicated circuit tariff (for hot water/slab heating), which has an average usage of 2.8 MWh per annum. | | | |
|  | Low Voltage Medium | Small Commercial | Low Voltage Medium | 20 to 400 MWh annual energy usage | <1,000 Volts |
| | | Large residential customers may be included in this category. | | | |
|  | Low Voltage Large | Large Commercial | Low Voltage Large kVA Time of Use (LVkVATOU) | >400 MWh annual energy usage and/or >150 kVA Maximum Demand | <11,000 Volts |
|  | High Voltage Large | Industrial | High Voltage kVA Time of Use (HVkVATOU) | High voltage supply | 11,000 to 22,000 Volts |
|  | Sub-transmission Large | Large Industrial | Sub-transmission kVA Time of Use (SubTkVATOU) | Sub-transmission supply | > 66,000 Volts |

UE's proposed allocation of individual tariffs into tariff classes is shown below.

**Table 3-1: Proposed Tariff Class Allocation**

| Tariff Code | Tariff Open New Connection | Tariff Description | Tariff Class |
|---|---|---|---|
| Unmet | Yes | Unmetered supplies | Low voltage small |
| LVS1R | Yes | Low voltage small 1 rate | |
| LVS2R | No | Low voltage small 2 rate | |
| LVDed[1] | Yes | Dedicated circuit | |
| WET2Step | No | Winter economy tariff | |
| TOD | Yes | Time of Day | |
| TOD9 | Yes | Time of Day 9pm off peak | |
| RESKW1R[2] | Yes | Seasonal demand anytime energy rate | |
| TODFLEX | Yes | Time of Day Flexible | |
| LVM1R[4] | Yes | Low voltage medium 1 rate | Low voltage medium |
| LVM2R5D | No | Low voltage medium 2 rate 5 day | |
| LVM2R7D | No | Low voltage medium 2 rate 7 day | |
| LVkWTOU | No | Low voltage KW time of use | |
| LVkWTOUH | No | Low voltage KW time of use – HOT | |
| TOU[4] | Yes | Time of use | |
| LVMKW1R[2,] | Yes | Seasonal Demand anytime energy rate | |
| LVMKWTOU[2, 3, 4] | Yes | Seasonal Demand anytime energy rate | |
| LVL2R | No | Low voltage large 2 rate | Low voltage large |
| LVL1R | No | Low voltage large 1 rate | |
| LVkVATOU | Yes | Low voltage large KVA time of use | |
| HVkVATOU | Yes | High voltage KVA time of use | High voltage large |
| SubTkVATOU | No | Subtransmission KVA time of use | Subtransmission large |

1. LVDed not available to customers with solar PV installed.
2. Not available to customers with dedicated hot water meters
3. Fully cost reflective demand tariff
4. Open to new connection where customer consumes >20MWh <160MWh pa

NB: Where the tariff also includes PFIT, a prefix of "F" will apply eg.FLVS1R

UE's 2018 Network Use of System tariffs (NUoS) for standard control services reflect the underlying structure of both the TUoS and DUoS charges. That is, the structures of the Transmission Use of System (TUoS) and Distribution Use of System (DUoS) tariffs are identical and the NUoS rates are the simple addition of the two.

The following sections set out the charging parameters for each proposed tariff, in accordance with clause 6.18.2(b)(3) of the Rules.

## 3.4. Charging parameters

### 3.4.1. Charging Parameters for DUoS Tariffs

The following table provides the charging parameters for each open Distribution tariff:

**Table 3-2: Charging parameters – DUOS**

| DUoS Tariffs | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Charging Parameters | Units | Unmet | LVS1R | RESKW1R | LVDed | TOD/TOD9/ TODFLEX | LVM1R | LVMKWTOU/ LVMKW1R | TOU | LVkVA TOU | HVkVA TOU |
| Standing Charge | c/day | | ✓ | | | ✓ | ✓ | | | | |
| Anytime energy | c/kWh | | | ✓ | | | | ✓ | | | |
| Summer peak energy | c/kWh | ✓ | ✓ | | | ✓ | ✓ | | ✓ | ✓ | ✓ |
| Non summer peak energy | c/kWh | ✓ | ✓ | | | ✓ | ✓ | | ✓ | ✓ | ✓ |
| Summer shoulder energy | c/kWh | | | | | ✓ | | | | | |
| Non summer shoulder energy | c/kWh | | | | | ✓ | | | | | |
| Off peak energy | c/kWh | ✓ | | | ✓ | ✓ | | | ✓ | ✓ | ✓ |
| Rolling Peak Demand | c/kVA/day | | | | | | | | | ✓ | ✓ |
| Summer demand incentive charge | c/kVA/day | | | | | | | | ✓ | ✓ | ✓ |
| Summer demand charge | c/kW/day | | | ✓ | | | | ✓ | | | |
| Non summer demand charge | c/kW/day | | | ✓ | | | | ✓ | | | |
| | | | | | | | | | | | |

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#### 3.4.2. Charging Parameters for TUoS Tariffs

The following table provides the charging parameters for each open Transmission tariff:

**Table 3-3: Charging parameters–TUOS**

| TUoS Tariffs | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Charging Parameters | Units | Unmet | LVS1R | RESKW1R | LVDed | TOD/TOD9/ TODFLEX | LVM1R | LVMKWTOU/ LVMKW1R | TOU | LVkVATOU | HVkVA TOU |
| Standing Charge | c/day | | | | | | | | | | |
| Anytime energy | c/kWh | | | ✓ | ✓ | | | ✓ | | | |
| Summer peak energy | c/kWh | ✓ | ✓ | | | ✓ | ✓ | | ✓ | ✓ | ✓ |
| Non summer peak energy | c/kWh | ✓ | ✓ | | | ✓ | ✓ | | ✓ | ✓ | ✓ |
| Summer shoulder energy | c/kWh | | | | | ✓ | ✓ | | | | |
| Non summer shoulder energy | c/kWh | | | | | ✓ | ✓ | | | | |
| Off peak energy | c/kWh | | | | | | | | | | |
| Rolling Peak Demand | c/kVA/day | | | | | | | | | ✓ | ✓ |
| Summer demand incentive charge | c/kVA/day | | | | | | | | ✓ | ✓ | ✓ |
| Summer demand charge | c/kW/day | | | ✓ | | | | ✓ | | | |
| Non summer demand charge | c/kW/day | | | ✓ | | | | ✓ | | | |

## 3.5. Tariff Availability per tariff class

The following section outlines which type of customer the UE network tariff is available to:

### 3.5.1. Low Voltage Small

- Unmet — Available to unmetered supplies.
- LVS1R — The Low Voltage Small Single Rate tariff is available to customers consuming less than 20 MWh per annum.
- LVDed — The low voltage dedicated circuit tariff is available on request to eligible new connections on the LVS1R tariff with hot water and or slab heating consuming less than 20MWh per annum. Not available to customers with solar PV systems.
- TOD — The Time of Day tariff is available to customers consuming less than 20MWh per annum with an interval meter.
- TOD9 — The Time of Day 9pm off peak tariff is available to customers consuming less than 20MWh per annum with an interval meter.
- TODFLEX — The Time of Day Flexible Tariff is available to residential customers with an AMI enabled interval meter.
- RESKW1R — Seasonal workday demand with anytime energy available to customers with an AMI enabled interval meter consuming less than 20MWh per annum. Not available to customers with dedicated off peak meter.

### 3.5.2. Low Voltage Medium

- LVM1R — The low voltage medium single rate tariff is available to customers consuming between 20 MWh and 160 MWh per annum.
- TOU — The Time of Use tariff is available to customers consuming between 20 MWh and 160 MWh per annum, and demand of less than 150kVA pa with an interval meter.
- LVMKWTOU — This Time of Use/demand tariff is available to customers consuming between 20 MWh and 400 MWh per annum. Fully cost reflective demand tariff.
- LVMKW1R — This Time of Use/demand tariff is for eligible customers consuming between 20 MWh and 400 MWh per annum. Transition tariff took effect from January 1st 2017. Partially cost reflective from 2017 which transitions to full cost reflectivity by 2020.

#### 3.5.3. Low Voltage Large

- LVkVATOU The Low Voltage Large kVA Time of Use tariff is available to large customers consuming 400 MWh or above, and/or a demand of 150 kVA or above. A minimum chargeable rolling demand of 150 kVA applies.

#### 3.5.4. High Voltage Large

- HVkVATOU The High Voltage kVA Time of Use tariff is available to large customers consuming 400 MWh or above, and/or a demand of 150 kVA or above. A minimum chargeable rolling demand of 1,150 kVA applies.

#### 3.5.5. Subtransmission Large

- SubTkVATOU: The Subtransmission kVA Time of Use tariff is closed to new connections. It has a similar makeup (different rates) to the High Voltage kVA Time of Use Tariff; however a minimum chargeable rolling demand of 11,100 kVA applies.

## 3.6. Operating periods, time of day and season definitions

The tables below provide a reference showing the time of day for peak, off peak and shoulder periods together with providing details of UE seasonal charging parameters.

**Table 3-4: Tariff - HVkVATOU, LVkVATOU, SUBTkVATOU**

<table>
<tr><td>Business Days</td><td colspan="6">N/A</td><td colspan="16">Rolling Demand</td><td colspan="8">N/A</td></tr>
<tr><td>Business Days</td><td colspan="6">Off Peak</td><td colspan="16">Peak</td><td colspan="8">Off Peak</td></tr>
<tr><td>Business Days Summer Only</td><td colspan="14">N/A</td><td colspan="6">Summer Demand</td><td colspan="10">N/A</td></tr>
<tr><td>Weekends & Public Holidays</td><td colspan="30">Off Peak</td></tr>
<tr><td>1/2 hr interval</td><td>1</td><td>2</td><td></td><td></td><td>13</td><td>14</td><td>15</td><td>16</td><td></td><td></td><td>27</td><td>28</td><td>29</td><td>30</td><td>31</td><td>32</td><td>33</td><td>34</td><td>35</td><td>36</td><td>37</td><td>38</td><td>39</td><td>40</td><td>41</td><td>42</td><td></td><td>46</td><td>47</td><td>48</td></tr>
<tr><td>Local Time</td><td colspan="2">12:00 AM</td><td colspan="2">to</td><td colspan="2">6:00 AM</td><td colspan="2">7:00 AM</td><td colspan="2">to</td><td colspan="2">1:00 PM</td><td colspan="2">2:00 PM</td><td colspan="2">3:00 PM</td><td colspan="2">4:00 PM</td><td colspan="2">5:00 PM</td><td colspan="2">6:00 PM</td><td colspan="2">7:00 PM</td><td colspan="2">8:00 PM</td><td colspan="2">to</td><td colspan="2">11:00 PM</td></tr>
</table>

**Table 3-5: Tariff – TOU**

| | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Business Days | Off Peak | | | | | | Peak | | | | | | | | | | | | | | | | | | | | | | Off Peak | |
| Business Days Summer Only | N/A | | | | | | | | | | | | Summer Demand | | | | | | | | | | N/A | | | | | | | |
| Weekends & Public Holidays | Off Peak | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1/2 hr interval | 1 | 2 | | | 13 | 14 | 15 | 16 | | | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 | 41 | 42 | | 46 | 47 | 48 |
| Local Time* | 12:00 AM | | to | | 6:00 AM | | 7:00 AM | | to | | 1:00 PM | | 2:00 PM | | 3:00 PM | | 4:00 PM | | 5:00 PM | | 6:00 PM | | 7:00 PM | | 8:00 PM | | to | | 11:00 PM | |

**Table 3-6: Tariff – TOD**

| | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Business Days | Off Peak | | | | | | Shoulder | | | | | | | | Peak | | | | | | | | | | | | | | Off Peak | |
| Weekends & Public Holidays | Off Peak | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1/2 hr interval | 1 | 2 | | | 13 | 14 | 15 | 16 | | | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 | 41 | 42 | | 46 | 47 | 48 |
| Local Time* | 12:00 AM | | to | | 6:00 AM | | 7:00 AM | | to | | 1:00 PM | | 2:00 PM | | 3:00 PM | | 4:00 PM | | 5:00 PM | | 6:00 PM | | 7:00 PM | | 8:00 PM | | to | | 11:00 PM | |

**Table 3-7: Tariff – TOD9**

| | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Business Days | Off Peak | | | | | | Shoulder | | | | | | | | Peak | | | | | | | | | | | | Off Peak | | | |
| Weekends & Public Holidays | Off Peak | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1/2 hr interval | 1 | 2 | | | 13 | 14 | 15 | 16 | | | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 | 41 | 42 | 43 | 44 | 45 | 48 |
| Local Time* | 12:00 AM | | to | | 6:00 AM | | 7:00 AM | | to | | 1:00 PM | | 2:00 PM | | 3:00 PM | | 4:00 PM | | 5:00 PM | | 6:00 PM | | 7:00 PM | | 8:00 PM | | 9:00 PM | | 10-12 PM | |

**Table 3-8: Tariff – TODFLEX**

| | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Weekdays | Off Peak | | | | | | Shoulder | | | | | | | | Peak | | | | | | | | | | | | Shoulder | | Off Peak | |
| Weekends | Off Peak | | | | | | Shoulder | | | | | | | | | | | | | | | | | | | | | | Off Peak | |
| 1/2 hr interval | 1 | 2 | | | 13 | 14 | 15 | 16 | | | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 | 41 | 42 | 43 | 44 | 45 | 48 |
| Local Time* | 12:00 AM | | to | | 6:00 AM | | 7:00 AM | | to | | 1:00 PM | | 2:00 PM | | 3:00 PM | | 4:00 PM | | 5:00 PM | | 6:00 PM | | 7:00 PM | | 8:00 PM | | 9:00 PM | | 10-12 PM | |

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**Table 3-9: Tariff – RESKW1R (Seasonal Demand anytime energy Residential)**

| | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Demand | | | | | | | | | | | | | | | Peak | | | | | | | | | | | | | | | |
| Energy | Anytime rate | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1/2 hr interval | 1 | 2 | | | 13 | 14 | 15 | 16 | | | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 | 41 | 42 | 43 | 44 | 45 | 48 |
| Local Time* | 12:00 AM | | to | | 6:00 AM | | 7:00 AM | | to | | 1:00 PM | | 2:00 PM | | 3:00 PM | | 4:00 PM | | 5:00 PM | | 6:00 PM | | 7:00 PM | | 8:00 PM | | 9-10 PM | | 10-12 PM | |

NOTE: Monthly maximum demand is based on WORK DAYS (i.e. excluding weekends and public holidays).

**Table 3-10: Tariff - LVDED (Dedicated Load)**

| | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Any Day | Off Peak | | | | | | N/A | | | | | | | | | | | | | | | | | | | | | | Off Peak | |
| 1/2 hr interval | 1 | 2 | 3 | 4 | 13 | 14 | 15 | 16 | | | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 | 41 | 42 | | 46 | 47 | 48 |
| Local Time* | 12:00 AM | | 1:00am | | 6:00 AM | | 7:00 AM | | to | | 1:00 PM | | 2:00 PM | | 3:00 PM | | 4:00 PM | | 5:00 PM | | 6:00 PM | | 7:00 PM | | 8:00 PM | | to | | 11:00 PM | |

NOTE: Off peak for LVDED is for up to 8 hours between 11pm and 7am local time controlled at United Energy's discretion. Note that if any controlled load boosts occur outside the off-peak periods, these will be charged at the premise's corresponding peak tariff rate.

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**Table 3-11: Tariff - LVS1R,**

| | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| All times | Peak | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1/2 hr interval | 1 | 2 | 3 | 4 | 13 | 14 | 15 | 16 | | | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 | 41 | 42 | | | 47 | 48 |
| EST | 12:00 AM | | 1:00am | | 6:00 AM | | 7:00 AM | | to | | 1:00 PM | | 2:00 PM | | 3:00 PM | | 4:00 PM | | 5:00 PM | | 6:00 PM | | 7:00 PM | | 8:00 PM | | to | | 11:00 PM | |

NOTE: In order to maintain the same time limits during Eastern Standard Time (EST) and Daylight Saving Time (DST), billing data is adjusted by shifting the data forward an hour to accommodate for the time shift during DST.

**Table 3-12: Tariff – LVMKWTOU, LVMKW1R (Seasonal Demand anytime energy Business)**

| | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Demand | | | | | | | | | Peak | | | | | | | | | | | | | | | | | | | | | |
| Energy | Anytime rate | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1/2 hr interval | 1 | 2 | | | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 29 | 30 | | | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 | 41 | 42 | 43 | 44 | 45 | 48 |
| Local Time* | 12:00 AM | | to | | 8:00 AM | | 9:00 AM | | 10:00AM | | 11:00AM | | 12:00PM | | to | | 4:00 PM | | 5:00 PM | | 6:00 PM | | 7:00 PM | | 8:00 PM | | 9-10 PM | | 10-12 PM | |

NOTE: Monthly maximum demand is based on WORK DAYS (i.e. excluding weekends and public holidays).

**Table 3-13: Seasonal Periods (all tariffs except TODFLEX & RESKW1R & LVMKWTOU & LVMKW1R)**

| Months | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Period | Non Summer | | | | Summer | | | | | Non Summer | | |

**Table 3-14: Seasonal Periods (TODFLEX)**

**(Summer commences 1st day Daylight savings and finishes last day of Daylight savings)**

| Months | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Period | Non Summer | | | Summer | | | | | | Non Summer | | |

**Table 3-15: Seasonal Periods (RESKW1R & LVMKW1R & LVMKWTOU)**

| Months | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Period | Non Summer | | | | | Summer | | | | Non Summer | | |

# 4. Pricing principles and UE's tariff strategy

## 4.1. Regulatory requirements

In November 2014 the Australian Energy Market Commission (AEMC) made a new National Electricity Rule that requires distribution network businesses to develop prices that better reflect the costs of providing services to customers. The Rules establishes a new pricing objective and pricing principles to guide tariff setting. The key change is the requirement that each tariff be based on the Long Run Marginal Cost (LRMC) of providing network services. Under the new Rule, network pricing will be more cost-reflective, thereby providing a more efficient price signal for investment and usage decisions. Clause 6.18.5 of the Rules requires UE to comply with the following pricing principles.

(a) For each tariff class, the revenue expected to be recovered should lie on or between:

(i) an upper bound representing the stand alone cost of serving the customers who belong to that class; and

(ii) a lower bound representing the avoidable cost of not serving those customers.

(b) Each tariff must be based on the *long run marginal cost* of providing the service to which it relates to the *retail customers* assigned to that tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to:

(i) the costs and benefits associated with calculating, implementing and applying that method as proposed;

(ii) (ii) the additional costs likely to be associated with meeting demand from retail customers that are assigned to that tariff at times of greatest utilisation of the relevant part of the distribution network; and

(iii) the location of retail customers that are assigned to that tariff and the extent to which costs vary between different locations in the distribution network.

(c) The revenue expected to be recovered from each tariff must:

(i) reflect the Distribution Network Service Provider's total efficient costs of serving the retail customers that are assigned to that tariff;

(ii) when summed with the revenue expected to be received from all other tariffs, permit the Distribution Network Service Provider to recover the expected revenue for the relevant services in accordance with the applicable distribution determination for the Distribution Network Service Provider; and

(iii) minimise distortions to the price signals for efficient usage that would result from tariffs that comply with the pricing principle set out in paragraph (b).

(d) A Distribution Network Service Provider must consider the impact on retail customers of changes in tariffs from the previous regulatory year and may vary tariffs from those that comply with paragraphs (a) to (c) to the extent the Distribution Network Service Provider considers reasonably necessary having regard to:

(i) the desirability for tariffs to comply with the pricing principles referred to in paragraphs (b) and (c), albeit after a reasonable period of transition (which may extend over more than one regulatory control period);

(ii) the extent to which retail customers can choose the tariff to which they are assigned; and

(iii) the extent to which retail customers are able to mitigate the impact of changes in tariffs through their usage decisions.

(e) The structure of each tariff must be reasonably capable of being understood by retail customers that are assigned to that tariff, having regard to:

(i) the type and nature of those retail customers; and

(ii) the information provided to, and the consultation undertaken with, those retail customers.

(f) A tariff must comply with the Rules and all applicable regulatory instruments.

This section provides an overview of UE's approach to tariff-setting, including its application of the pricing principles described above. Section 6 of this Pricing Proposal demonstrates that UE's tariff proposals for 2018 comply with the Rules requirements and the AER's final determination.

## 4.2. UE's Network Tariff Objectives

UE's objectives have been developed through the consultation process with customers and retailers. The objectives describe the characteristics that our network tariffs should exhibit in order to:

• Give practical effect to the network pricing objective and the pricing principles set out in the Rules.

• To realise the potential benefits associated with technological change and more efficient network usage.

These objectives have provided a practical way for stakeholders to engage directly in the design of our new tariffs and provided a useful framework for testing our tariffs against the Rules principles.

The development and adjustment of UE tariffs broadly incorporates the following policy principles:

- **Simple:** Ability for customers to react and understand.
- **Attractive:** Desire of retailer to pass the tariff through to customers. While our preference is for our tariffs to be passed through to customers by the retailer we recognise that exposure of retailers to an input price signal should lead to competition and actions to manage the associated cost risk.
- **Forward Looking:** Ability to deal with changing market conditions while being technology and policy agnostic.
- **Manage Volatility**: Desire for low year-on-year volatility.
- **Predictable:** Ability for customers to forecast and understand impacts - no bill shock.
- **Cost-reflective:** Reduce inefficiencies and cross-subsidies and adapt to different types of customer load profiles and technologies.
- **Compliant:** Compliance within the various regulatory and legislative criteria.

UE's tariff proposals may reflect a compromise between these competing pricing objectives. UE's overall approach is to satisfy the above principles to the greatest extent possible, subject to ensuring that UE's regulatory obligations are fully satisfied.

## 4.3. Stakeholder consultation & tariff initiatives

United Energy (UE) is committed to customer and key stakeholders to better inform public policy positions and on major elements of our business that impact customers, including tariffs.

While distributors do not traditionally deal directly with end use customers, we understand that customers ultimately bear the cost of our services. In this regard, UE plays a significant role in distributing electricity to many Victorian business and domestic customers. Together with our core objectives of delivering energy in a safe and reliable manner, UE strives to provide an efficient and cost effective service for our customers.

Our stakeholder engagement initiatives have addressed a broad range of issues including: the case for tariff reform; tariff reform objectives; proposed tariff strategy; different options and structures; transition arrangements; the scope and purpose of the Tariff Structure Statement; customer impact analysis and the evolving benefits of cost reflective network tariffs.

Our approach to stakeholder engagement during the development of our TSS and subsequent pricing proposals was based on the strategic approach we established in February 2014, in preparation for our Electricity Distribution Pricing Review. We recognised that in order to meet changing community expectations reflected in Chapter 6 of the National Electricity Rules (NER) and the AER Better Regulation Guidelines, we needed fresh thinking about the way we communicate. We developed our Customer and Stakeholder Engagement Strategy to outline our commitment and approach.

Our stakeholder engagement objectives are illustrated in Figure 4.1.

**Figure 4.1: Stakeholder engagement objectives and outcomes**

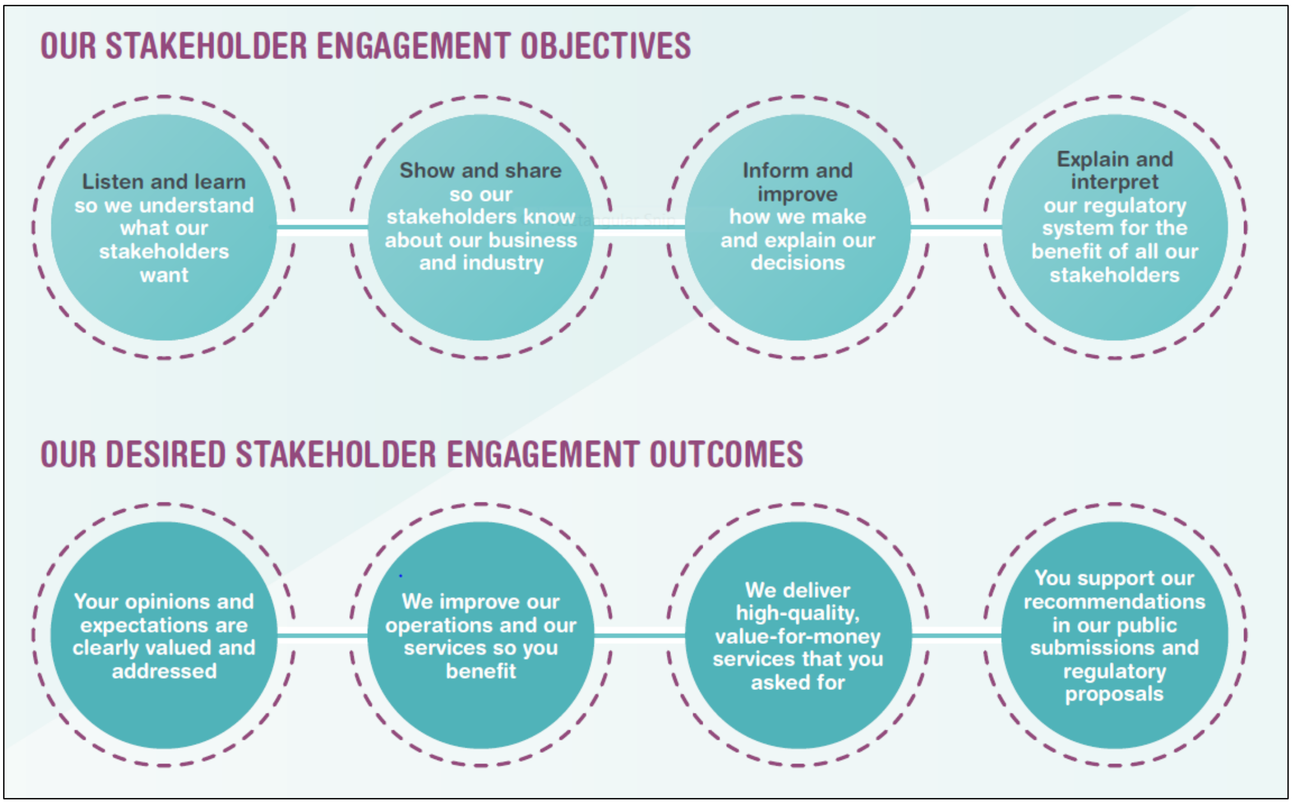


Figure 4.2 provides a summary of the key drivers that stakeholders emphasised as part of the consultation processes that UE has engaged in since mid-2014.

**Figure 4.2: Stakeholder key drivers**


#### 4.3.1. Seasonal demand tariff options for Residential low voltage customers (RESKW1R)

In November 2014 the Australian Energy Market Commission (AEMC) made a new National Electricity Rule (NER, cl. 6.18.4.) that requires distribution network businesses to develop prices that better reflect the costs of providing services to customers. Whilst we are aware of our obligations under the NER, UE is committed to achieving greater alignment between individual customer usage profiles and their resultant cost on the UE network. We believe that customers will benefit through;

- Improved equity and fairness due to reduction in cross subsidies between different types of network users. For example, air conditioning, solar PV and seasonal consumption.
- Reduced cost of network investment as customers respond to price signals by shifting discretionary load to off peak periods and reducing load in peak demand periods.
- Benefit realisation of the AMI (smart meter) program where greater insight about customer consumption profiles will lead to overall reduction in cost to network users.
- Appropriate price signals regarding investment in new technology to drive the most efficient network solutions for our customers in the future.

UE considers that fundamental to transitioning to a more cost reflective tariff structure is the requirement to reduce the emphasis on fixed and usage based charges and introduce demand tariff components (aligned to network peak constraints). Having introduced a residential demand tariff on an opt-in basis for 2015, UE will continue to offer a fully cost reflective residential demand and energy based tariff (RESKW1R) on an "opt-in" basis for the balance of the current regulatory period.

The table below provides a summary of charge parameters and an indication of how the DUoS is allocated between demand/energy components and summer/non-summer periods for 2018.

**Table 4-1: Seasonal Demand Anytime Energy Residential Tariff Specification (Indicative DUoS)**

| Tariff Name | Component | Description | Charging Parameter | Rate Summer (Dec-Mar) | Rate Non Summer (Apr-Nov) | Criteria | Average DUOS Bill (4,200KWh pa) | DUoS Charge Split | Billing |
|---|---|---|---|---|---|---|---|---|---|
| Seasonal demand / single rate (RESKW1R) | Energy | Anytime energy rate on any day type. | c/kWh | 2.71 | 2.71 | Monthly energy kWh. Summer = Dec-Mar | $114 | 40% | Monthly |
| | Demand | - Seasonal demand elements.<br>- Premium for Summer reflects network constraint. | $/kW/month | 26.13 | 10.31 | - Recorded monthly maximum demand between **3-9PM** local time on business days. Summer = Dec -Mar<br>Monthly Minimum of 1.5KW | $165 | 60% | |
| | | **Seasonal Split** | $/Month | $34.46 | $17.68 | Total | $279 | 100% | |

#### 4.3.2. Seasonal demand tariff options for Small Business low voltage customers (LVMKWTOU & LVMKW1R)

UE introduced an optional small business tariff with demand components in 2016. In the Revised TSS (29 April 2016), subsequently approved by the AER (24 August 2016), United Energy proposed that customers exceeding 40MWh consumption per annum transition to a new tariff with demand components by 1st January 2017. This initial step targeted 25% of a customer's DUOS charge to be recovered from demand tariff components with a subsequent step up to 50% (of DUOS from demand) from 2019.

In accordance with the provisions of the Victorian Government AMI Tariffs Amendment Order (14th April 2016), United Energy made single rate and time of use tariffs available to low voltage small business customers consuming <40MWh per annum for the balance of the current regulatory control period. A further Victorian Government AMI Tariffs Amendment Order (12th September 2017) requires United Energy to raise the consumption threshold to <160MWh, below which a small business customer can opt out of a demand based tariff. Tariffs without demand elements will be rebalanced annually to target cost reflectivity and customers below the 160MWh threshold can also choose to opt in to the fully cost reflective tariff (LVMKWTOU).

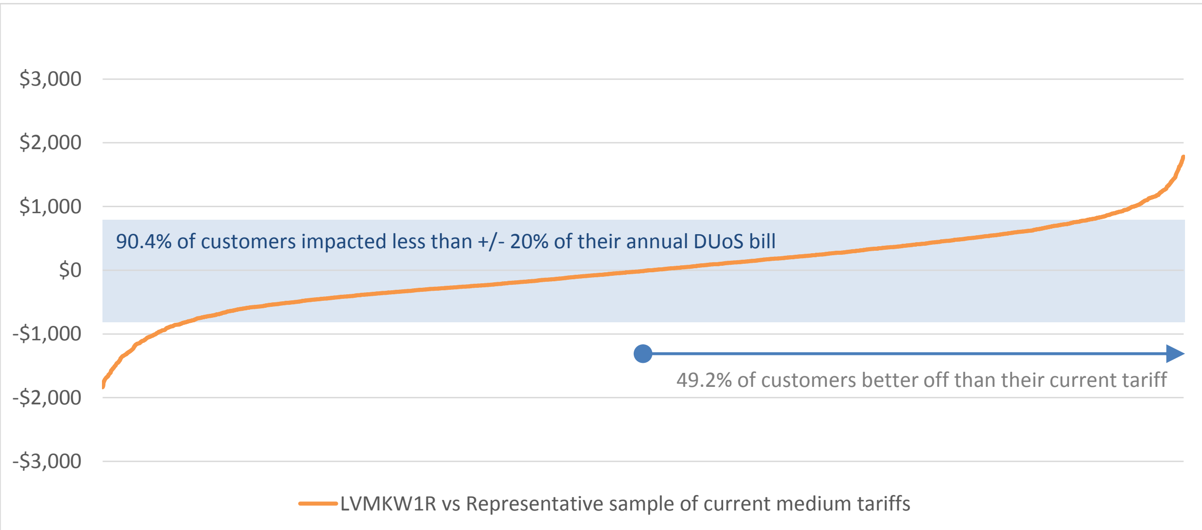
Table 4.2 provides a summary of LVMKW1R charge parameters and an indication of how the DUoS is allocated between demand/energy components and summer/non-summer periods for 2018.

**Table 4-2: LVMKW1R Small Business Tariff Specification (Indicative DUoS)**

| Tariff Name | Component | Description | Charging Parameter | Rate Summer (Dec-Mar) | Rate Non Summer (Apr-Nov) | Criteria | Indicative DUOS Bill (100MWh pa) | DUoS Charge Split | Billing |
|---|---|---|---|---|---|---|---|---|---|
| Small business demand / Time of Use (LVMKW1R) | Energy | Anytime energy rate on any day type. | c/kWh | 5.66 | 5.66 | Monthly energy kWh. Summer = Dec-Mar | $5,544 | 75% | Monthly |
| | Demand | - Seasonal demand elements.<br>- Premium for Summer reflects network constraint. | $/kW/month | 18.95 | 12.64 | - Recorded monthly maximum demand between **10-6PM** local time on business days. Summer = Dec -Mar<br>Monthly Minimum of 1.5KW | $1,817 | 25% | |
| | | **Seasonal Split** | $/Month | $641.19 | $599.53 | Total | $7,361 | 100% | |

Figure 4.3 following plots customer impacts for a representative sample of 3,800 low voltage medium "small business" customers in the >40MWh <400MWh per annum range. From the chart it is apparent that (on a revenue neutral 2018 DUoS tariff comparison basis) approximately 49.2% of customers would be better off on the transitional demand tariff (LVMKW1R) compared to their current tariff. We have sought to contain the DUoS cost impact of transition to customers, evidenced by approximately 90% of sample customers falling into the annual DUoS cost impact range of +/-20%. Notably, this is calculated before the customer has had an opportunity to change their consumption behaviour to obtain further cost reductions under the demand tariff structure.

**Figure 4-3: Impact analysis DUoS LVMKW1R vs 2018 LVM tariffs 40-400MWh pa**



## 4.4. Future tariff developments

Clause 6.18.2 (b)(5) requires UE set out the nature of any variation or adjustment to the tariff that could occur during the course of the regulatory year and the basis on which it could occur. For the forthcoming regulatory year, UE does not anticipate any variation to the tariffs set out in this Pricing Proposal other than those indicated in section 4.3.1.

UE is committed to tariff reform as set out in our Revised Tariff Structure Statement 2017-2020 (TSS) submitted to the AER in September 2017. UE also supports tariff reform as part of a wider industry transformation that will;

- Incentivise demand management solutions
- Encourage competition
- Facilitate storage technologies
- Reduce the long term costs to consumers if we are able to reduce demand at peak times

Our TSS included important evolutionary steps on the path to the network of the future and includes;

- The introduction of demand components for residential customer measured between 3pm-9pm on work days.
- The introduction of demand components for small business customers measured between 10am-6pm on work days.

In addition to the tariff initiatives described in section 4.3.1 and 4.3.2, and as set out in our TSS, UE will continue to provide updated information on future price changes in accordance with the requirements of Clause 6.18.9 of the Rules.

## 4.5. Publication of information regarding tariffs and tariff classes

Clause 6.18.9 of the Rules requires that a DNSP must maintain on its website:

1. a statement of the provider's tariff classes and the tariffs applicable to each class; and
2. for each tariff – the charging parameters and the elements of the service to which each charging parameter relates; and
3. a statement of expected price trends (to be updated for each regulatory year) giving an indication of how the DNSP expects prices to change over the regulatory control period and the reasons for the expected changes.

The Rules also require that the information for a particular regulatory year must, if practicable, be posted on the website 20 business days before the commencement of the relevant regulatory year and, if that is not practicable, as soon as practicable thereafter. In accordance with the Rules requirements and subject to AER approval, UE will make this information available on its website within the specified timeframe.

## 4.6. Expected DUoS price trends

The following table summarises UE's indicative movement in tariff charging parameters. The actual price movements in each year will remain subject to review at the time, following consideration of the objectives.

### Table 4-3: Indicative charging component movement in the 2016-2020 Regulatory Control Period

| Indicative relative charging component movement in the 2016-20 Regulatory Control Period | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Distribution Tariff Class and Tariff | Standing Charge | Summer Peak Energy | Non Summer Peak Energy | Summer Shoulder Energy | Non Summer Shoulder Energy | Off Peak Energy | Summer Capacity Max KW | Non-summer Capacity Max KW | Rolling Peak Demand | Summer Demand Incentive Charge |
| Low Voltage Small | | | | | | | | | | |
| Unmetered supplies | | - | - | | | - | | | | |
| Low voltage small 1 rate | - | ↑ | ↑ | | | | | | | |
| Dedicated circuit | | | | | | ↑ | | | | |
| Time of Day (TOD, TOD9 &TODFLEX) | - | ↑ | ↑ | - | - | - | | | | |
| RESKW1R | | ↓ | ↓ | ↓ | ↓ | ↓ | ↑ | ↑ | | |
| Low Voltage Medium | | | | | | | | | | |
| Low voltage medium 1 rate | - | ↑ | ↑ | | | | | | | |
| Time of Use | | ↑ | ↑ | - | - | - | | | | - |
| LVMKW1R | | ↓ | ↓ | ↓ | ↓ | ↓ | ↑ | ↑ | | |
| Low Voltage Large | | | | | | | | | | |
| Low voltage large KVA time of use | | - | - | - | - | - | | | - | - |
| High Voltage Large | | | | | | | | | | |
| High voltage KVA time of use | | - | - | - | - | - | | | - | - |
| Subtransmission Large | | | | | | | | | | |
| Subtransmission KVA time of use | | - | - | - | - | - | | | - | - |

↑ Increase relative to the average price movement per tariff.

↓ Decrease relative to the average price movement per tariff.

\- In line with average price movement per tariff.

A grey cell indicates that the corresponding charging parameter is not applicable for a particular tariff.

# 5. Standard control services - Tariffs and average charges

## 5.1. Regulatory Requirements

This section of the Pricing Proposal addresses clause 6.18.2(b)(4) of the Rules, which requires UE to provide details of the expected weighted average revenue for each tariff class for standard control services for the relevant regulatory year, 2018, and also for the current regulatory year, 2017. This section also provides useful information regarding the proposed average price change for each standard control tariff.

## 5.2. Proposed average increases and weighted average revenue

The following table indicates the weighted average movement of DUoS, TUoS and NUoS prices for each tariff between 2017 and 2018:

**Table 5-1: UE 2018 Tariff Price Movements**

**UED 2018 Tariff Price Movements**

| Description | Tariff Code | DUOS % price movement | TUOS % price movement | NUOS % price movement |
|---|---|---|---|---|
| **Class - Low Voltage Small** | | | | |
| Unmetered supplies | UnMet | 3.2% | -15.2% | -0.8% |
| Low voltage small 1 rate | LVS1R | 3.2% | -15.2% | -0.7% |
| Low voltage small 2 rate | LVS2R* | 3.2% | -15.2% | -0.5% |
| Dedicated circuit | LVDed | 3.2% | | 3.2% |
| Winter economy tariff | WET2Step* | 3.2% | -15.2% | -1.5% |
| Time Of Day | TOD | 3.2% | -15.2% | -0.3% |
| Time of Day 9pm Off Peak | TOD9 | 3.2% | -15.2% | -0.5% |
| Time of Day Flexible | TODFLEX | 3.2% | -15.2% | -0.4% |
| Low Voltage KW 1 rate (opt-in) | RESKW1R | 3.2% | -15.2% | -0.8% |
| **Class - Low Voltage Medium** | | | | |
| Low voltage medium 1 rate | LVM1R | 6.1% | -15.2% | 1.5% |
| Low voltage medium 2 rate 5 day | LVM2R5D* | 6.1% | -15.2% | 2.9% |
| Low voltage medium 2 rate 7 day | LVM2R7D* | 6.1% | -15.2% | 2.1% |
| Low voltage KW time of use | LVkWTOU* | 6.1% | -15.2% | 2.3% |
| Low voltage KW time of use - HOT | LVkWTOUH* | 6.1% | -15.2% | 3.4% |
| Time Of Use | TOU | 6.1% | -15.2% | 2.8% |
| Low voltage medium KW time of use (opt-in) | LVMKWTOU | 6.1% | -15.2% | 1.7% |
| Low voltage medium KW 1 rate (mandatory) | LVMKW1R | 6.1% | -15.2% | 1.8% |
| **Class - Low Voltage Large** | | | | |
| Low voltage large 2 rate | LVL2R* | 7.8% | -15.2% | 4.3% |
| Low voltage large 1 rate | LVL1R* | 7.8% | -15.2% | 1.0% |
| Low voltage large KVA time of use | LVkVATOU | 7.8% | -15.2% | 1.9% |
| **Class - High Voltage Large** | | | | |
| High voltage KVA time of use | HVkVATOU | 7.2% | -15.2% | -0.2% |
| **Class - Subtransmission Large** | | | | |
| Subtransmission KVA time of use | SubTkVATOU* | 7.2% | -15.2% | -7.0% |
| **Total** | | **5.2%** | **-15.2%** | **0.6%** |

*Tariff closed to premises not already taking supply under this tariff and new connections.

The average price movement for the 2018 DUOS tariffs is an increase of 5.2%. This increase is predominantly attributable to the X factor of -3.16% and S factor of 2.28% which manifests as a growth in DUoS revenue of 5.2% stemming from the AER's final decision in determining UE's efficient costs.

The average price movement for the 2018 TUOS tariffs is a decrease of 15.2%. This is determined by the maximum transmission revenue allowed for 2018 versus the estimated transmission revenue recovered in 2017 and 2016.

The table below indicates the expected weighted average DUoS revenue for each tariff class for standard control services by applying 2018 forecast quantities to prices for the relevant regulatory year 2018, and also for the current regulatory year, 2017.

**Table 5-2: UE DUOS Revenue by Tariff Class**

**UED DUOS Revenue by Tariff Class**

| Class | 2017 Revenue $M | | 2018 Revenue $M | | % Movement |
|---|---|---|---|---|---|
| Low Voltage Small | $ | 183.5 | $ | 189.4 | 3.2% |
| Low Voltage Medium | $ | 98.3 | $ | 104.2 | 6.1% |
| Low Voltage Large | $ | 89.9 | $ | 96.9 | 7.8% |
| High Voltage Large | $ | 19.1 | $ | 20.5 | 7.2% |
| Subtransmission Large | $ | 0.2 | $ | 0.2 | 7.2% |
| **Total** | **$** | **391.0** | **$** | **411.2** | **5.2%** |

The underlying drivers of DUOS prices are cost recovery to meet expanding network at peak times and replacement of infrastructure. The AER determines allowed revenue for distributors over a 5 year period with rates of increase subject to annual variation (see table 2.1).

**Figure 5-1: 2018 Expected Revenue % by Customer Class**

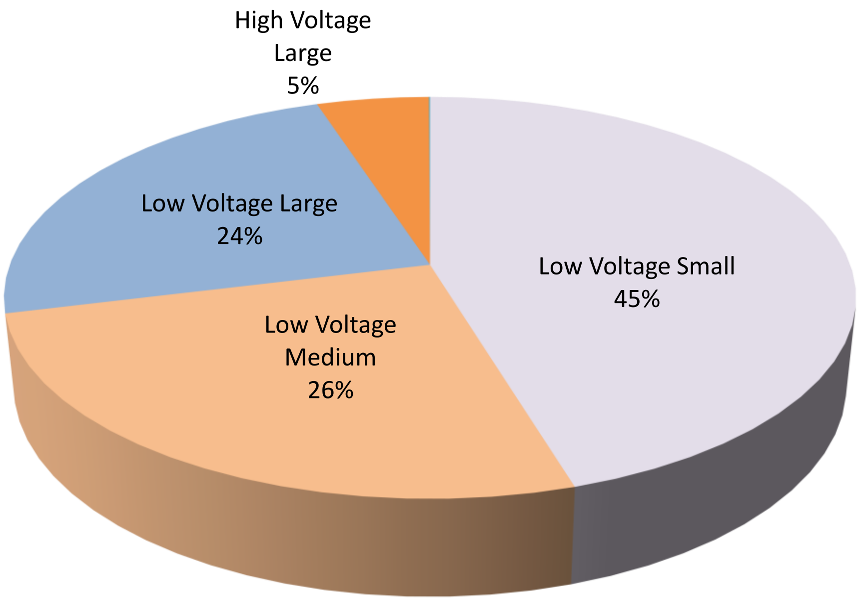
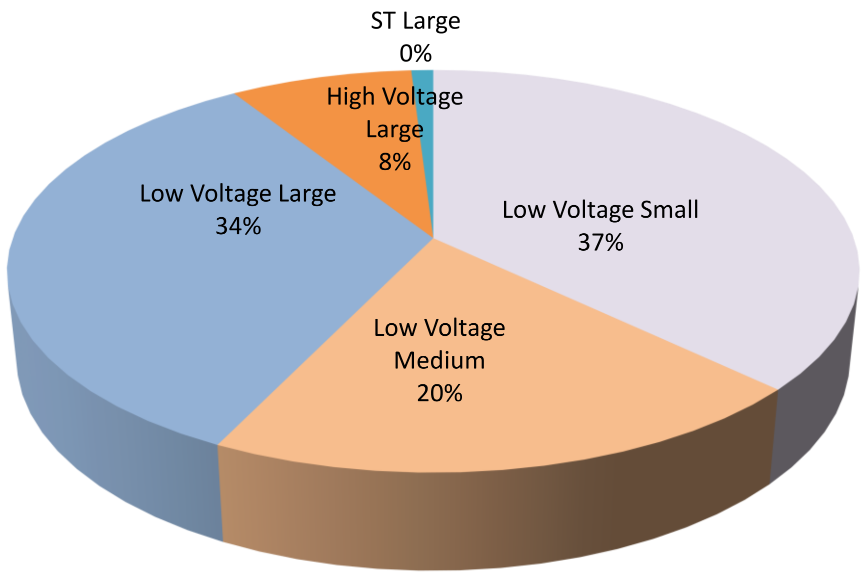


**Figure 5-2: 2018 Expected Energy Consumption % by Customer Class**



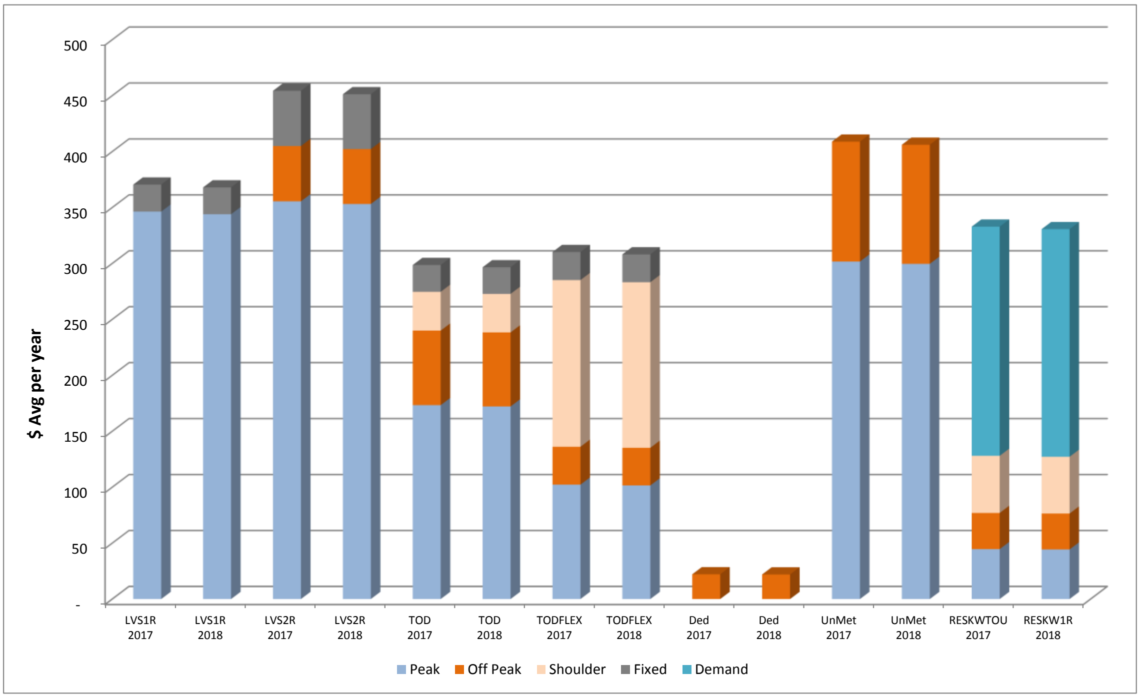

As shown by figure 1 and 2, UE's larger customers represent greater energy volumes, but contribute less revenue, and conversely the smaller customers represent lesser energy in comparison to revenue. This reflects the aggregate of assets required to service the customers. Smaller customers utilise more of the electricity network, therefore are priced comparatively higher than larger customers who use comparatively less of the electricity network.

## 5.3. Average tariff charges per customer for 2017 and 2018

This section presents the average yearly charges for UE's customers in 2017 and 2018. The following graphs are presented for each tariff class for standard control services.

### 5.3.1. Low Voltage Small Class

**Figure 5-3: Average Distribution and Transmission charge per customer – LV Small**




Each customer's bill is comprised of two components in addition to DUOS and TUOS. These components are Advanced Interval Meter (AMI) and PFIT charges which respectively recover revenue for AMI meters and solar rebates.

Table 5.2 indicates the average network charge and percentage increases for a residential customer with no electric hot water split by the 4 components for the residential tariffs. The average residential customer with no electric hot water uses approximately 4.2MWh per annum.

**Table 5-2: Residential Customer Impact based on 4.2MWh per annum**

| Indicative Tariff | Component | 2017 | 2018 | % Change | Delta $ |
|---|---|---|---|---|---|
| LVS1R | DUOS | $ 293.17 | $ 302.54 | 3.2% | $ 9.37 |
| | TUOS | $ 78.15 | $ 66.25 | -15.2% | -$ 11.90 |
| | Metering | $ 60.89 | $ 57.58 | -5.4% | -$ 3.31 |
| | Pass through | $ 22.80 | $ 19.74 | -13.4% | -$ 3.06 |
| | **Total** | **$ 455.00** | **$ 446.12** | **-2.0%** | **-$ 8.89** |
| RESKW1R | DUOS | $ 270.65 | $ 279.30 | 3.2% | $ 8.65 |
| | TUOS | $ 70.86 | $ 60.08 | -15.2% | -$ 10.78 |
| | Metering | $ 60.89 | $ 57.58 | -5.4% | -$ 3.31 |
| | Pass through | $ 22.80 | $ 19.74 | -13.4% | -$ 3.06 |
| | **Total** | **$ 425.19** | **$ 416.70** | **-2.0%** | **-$ 8.49** |

**Figure 5-4: Residential Customer Impact (LVS1R) 4.2MWh per annum**

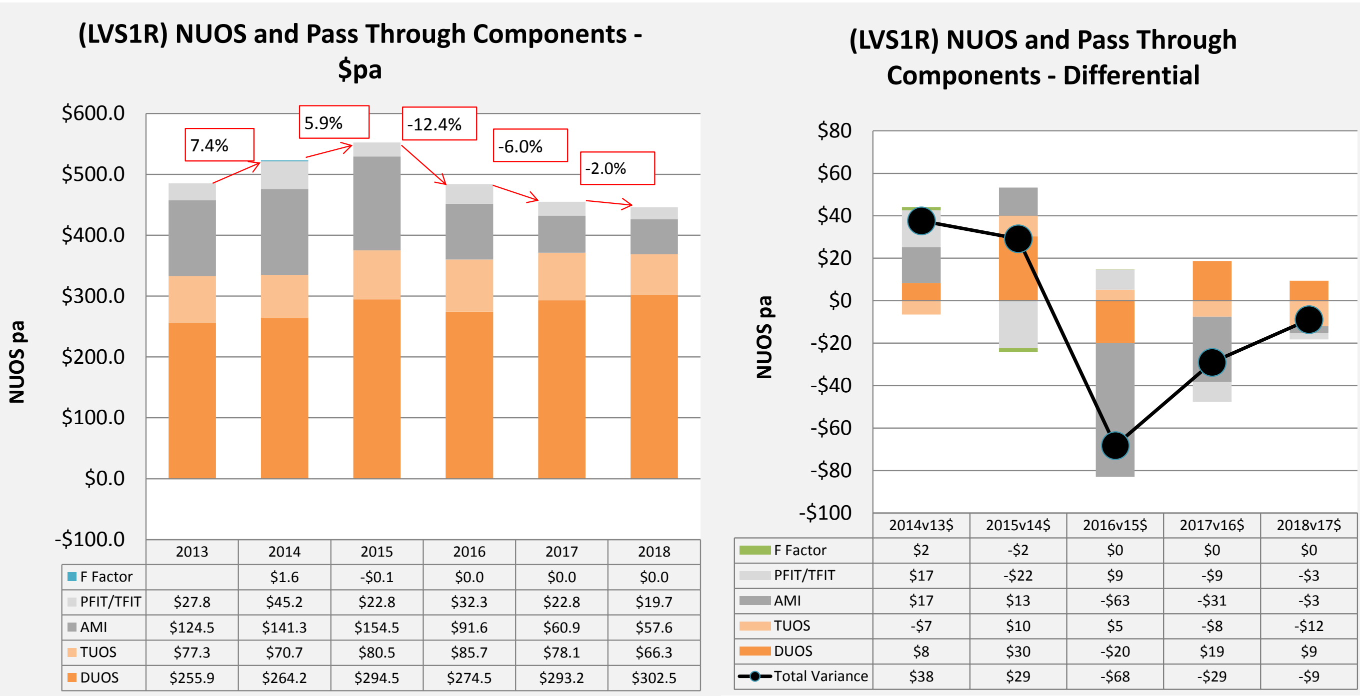
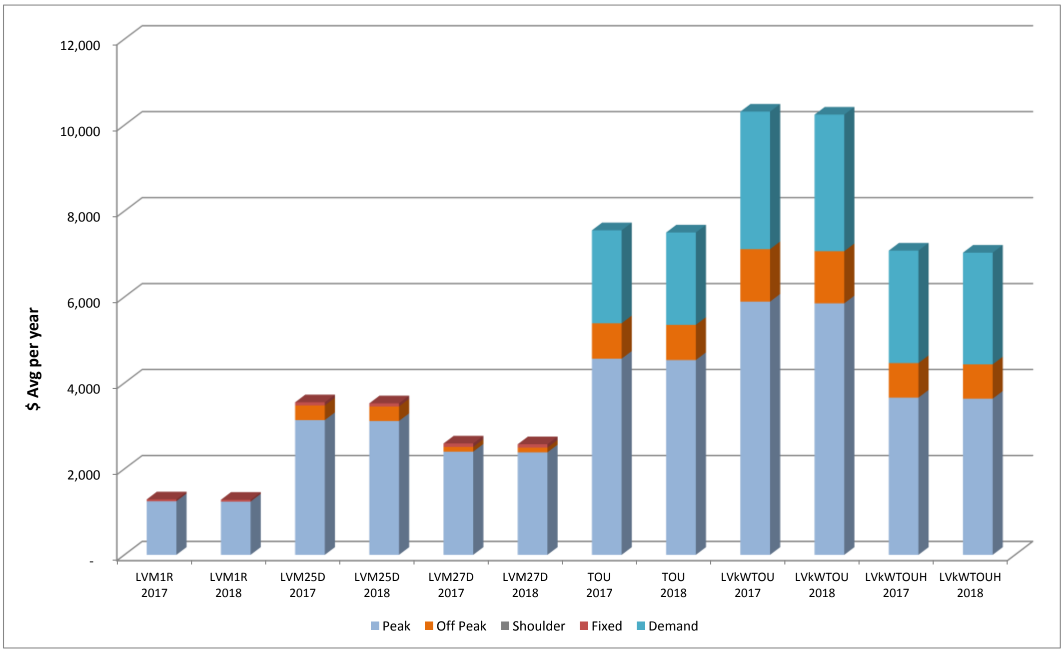



Figure 5-4 indicates that the annual decrease in NUOS & pass throughs from 2017 to 2018, for the most common residential tariff, is a decline of $8.89.

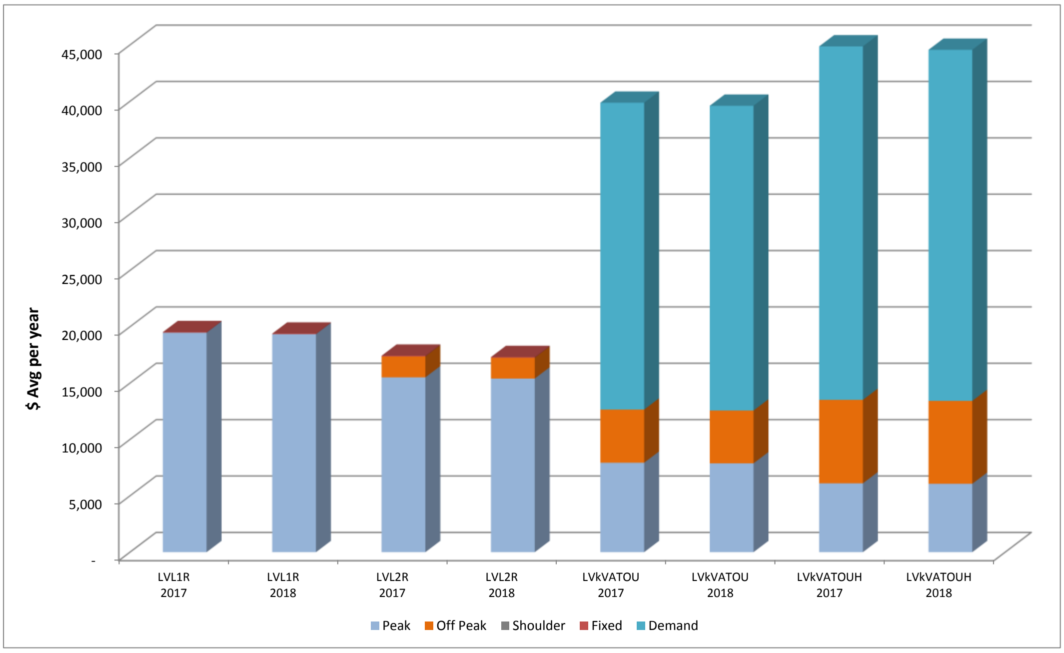
### 5.3.2. Low Voltage Medium Class

**Figure 5-5: Average network charge per customer – LV Medium**



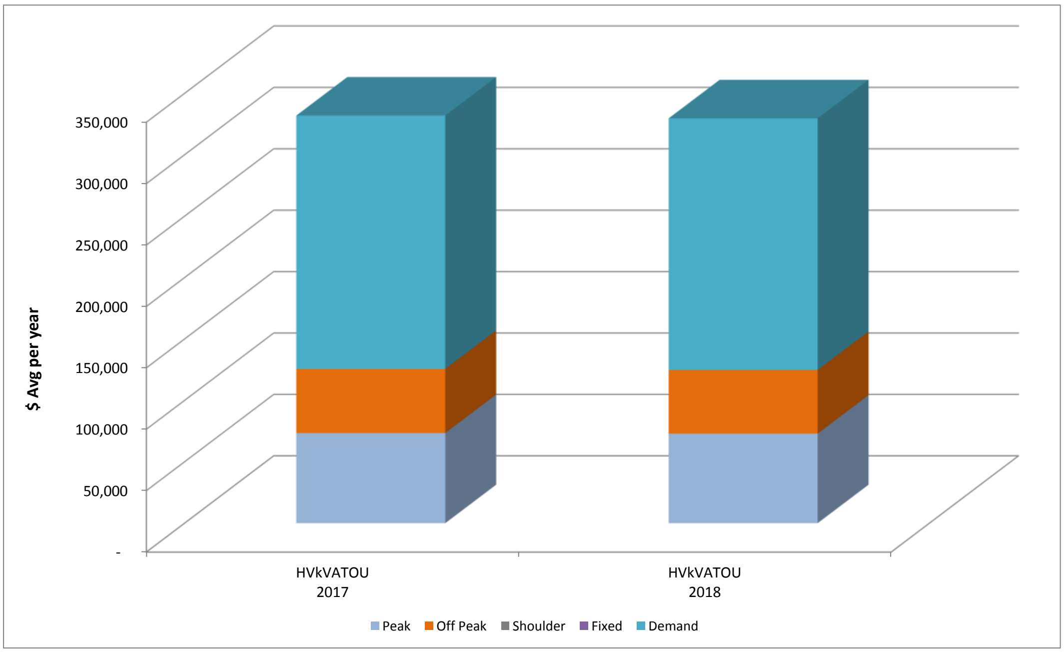

### 5.3.3. Low Voltage Large Class

**Figure 5-6: Average network charge per customer – LV Large**



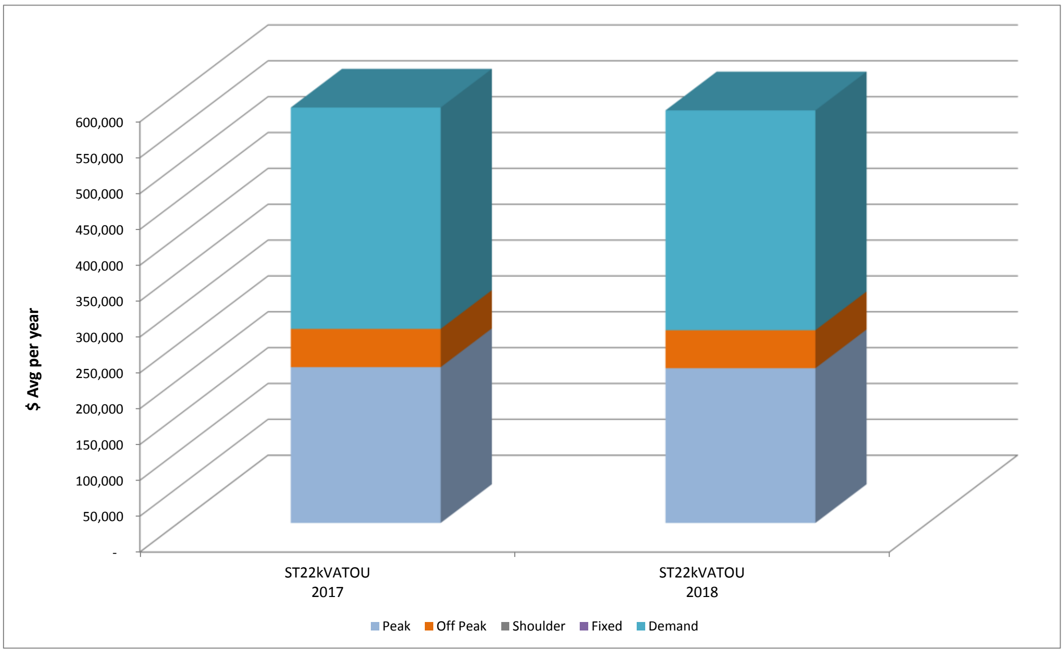
### 5.3.4. High Voltage Large Class

**Figure 5-7: Average network charge per customer – HV Large**




### 5.3.5. Sub-transmission Large Class

**Figure 5-8: Average network charge per customer – Subtransmission Large**



# 6. Demonstrating compliance with the Rules

## 6.1. Regulatory Requirements

Clause 6.18.2(b)(7) requires UE to demonstrate compliance with the Rules and any applicable distribution determination. Section 2 of this Pricing Proposal provided information in relation to the compliance issues arising from the AER's final determination, and the steps that UE has taken to ensure compliance. Furthermore, Section 3 described UE's approach to tariff-setting, including its compliance with the pricing principles in the Rules.

Notwithstanding the information already provided, this section provides further detailed information regarding UE's compliance with the Rules.

## 6.2. Compliance with the Revenue Cap formulae

Section 2.2 of this Pricing Proposal sets out the AER's revenue cap formulae that applies to UE for the 2016-2020 period. In its final decision the AER has determined UE's annual expected smoothed 2018 revenue to be $420.6 million (refer table 2.1). For 2018, the AER has indicated (PTRM model final decision) that UE shall apply an X factor of -3.16%, S factor of 2.28% and a CPI of 1.93%.

In order to determine the Total Annual Revenue target applicable to UE in 2018, application of further pricing components indicated in Table 6.1 below needs to be taken into account. More detailed descriptions of these elements and their application under the formulae are provided in section 2.2.

After the application of the formulae, UE's Annual Expected Smoothed Revenue for 2018 of $420.6 million is converted to a Total Annual Revenue of $411.2 million. The table below indicates the components of the formula and their impact.

**Table 6.1 – 2018 Total Annual Revenue Control Mechanism Formulae Components**

| Component | % Increase/Decrease |
|---|---|
| CPI | 1.93% |
| L | 0.04% |
| X | -3.16% |
| St** | 2.28% |
| I* | 0.24% |
| T | N/A for 2018 |
| **Total Annual Revenue ($ mil.)** | **$411.2** |

* For 2018 the AER has approved an 'I' factor of $1,000,000 relating to United Energy's fire prevention performance in Jan-Jun 2016 as assessed by the AER. In 2018 this will be a charge to customers as part of the DUOS rates. United Energy's fire prevention performance relating to Jul 2016 – Jun 2017 will be applied in 2019 DUOS rates.

** For 2018 the AER has approved an 'S' factor of 2.28% relating to United Energy's performance under the Service Target Performance Incentive Scheme (STPIS) in 2016 as assessed by the AER. In 2018 this will be a charge to customers as part of the DUOS rates.

## 6.3. Compliance with the side constraints

Section 2.3 provides details of the side constraint that applies to average price changes for tariff classes, and section 5.2 shows the DUOS movement by tariff. UE's Pricing Proposal is compliant with tariff class side constraints as set out in the AER's final determination.

## 6.4. Standalone and Avoidable Costs

### 6.4.1. Definition

**Standalone Costs:**
The Standalone cost for a tariff class is the cost of supplying only the tariff class concerned, with all other tariff classes not being supplied. If customers were to pay above the standalone cost then it would be economically beneficial for customers to switch to an alternate provider, and economically feasible for an alternate provider to operate. This creates the possibility of inefficient bypass of the existing infrastructure.

**Avoidable Costs:**
The Avoidable cost for a tariff class is the reduction in network cost that would take place if the tariff class were not supplied (whilst all other tariffs remained supplied). If customers were to be charged below the avoidable cost, it would be economically beneficial for the business to stop supplying the customers as the associated costs would exceed the revenue obtained from the customer.

### 6.4.2. Compliance

As noted in Section 4 of this Pricing Proposal, the Rules require that distribution tariffs should lie between the following upper and lower bounds:

- tariffs for each customer should generate revenue in excess of the avoidable cost to service the customer; and
- tariffs for each customer should generate revenue less than the cost of providing the service on a stand-alone basis to the customer.

To demonstrate that distribution tariffs fall between the avoidable cost "floor" and standalone cost "ceiling", UE must first apply a "cost of supply" methodology to assist in setting tariff rates. Broadly speaking, tariff rates are set to recover the allocated distribution revenue from that customer group. It is noted, however, that UE's approach to setting tariff rates is to consider all the pricing principles outlined in Section 4 of this Pricing Proposal.

The critical issue from a cost of supply modelling perspective is the method by which distribution revenue is allocated across the tariff groups. As network businesses are characterised by relatively high fixed costs and significant asset-sharing between customer groups, there is no unambiguously "correct" method for allocating costs. UE's method of allocation is based on each tariff's relative usage of UE's network assets.

In the model, customers are assigned into tariff groups based on voltage and demand characteristics. The consumption and demand characteristics for each tariff group are calculated as follows:

- For asset based costs, the quantity of assets and supporting infrastructure are assigned to the tariff groups according to the combined consumption and demand characteristics of all customers using the asset, e.g. HV assets are assigned to LV and HV customers, but not to sub-transmission customers. The cost of providing the assigned assets is then calculated for each customer class.
- For operational and maintenance costs, costs are directly attributed to particular asset classes, where possible, and the remaining costs are assigned to overheads

- Attributable costs use a weighted averaging to apply to the customers in each class
- Overheads are averaged over all customers
- Combining the overhead, maintenance and infrastructure costs, the overall cost of supply for each customer is calculated.
- UE has extended its “cost of supply” methodology to assess the avoidable and standalone costs. The avoidable cost model recognises that only a proportion of total costs are avoidable. In particular, the majority of asset-related costs cannot be avoided even if a particular customer group is no longer served. Inevitably, the assessment of which costs are avoidable is a matter of judgement. It should be noted, however, that as the avoidable costs are less than the total costs, UE’s cost of supply methodology will always set tariffs at a level that exceeds avoidable costs.

UE’s modelling of standalone costs is similarly based on the cost of supply model. The principal differences between the “basic” cost of supply estimates and standalone costs are:

- Standalone networks to serve a particular tariff class will not enjoy the benefit of diversity in peak demand between tariff classes;
- Economies of scale may be lost in supplying a subset of existing customers or tariffs;
- Greater urban congestion may result in the optimised replacement cost exceeding UE’s regulated asset value; and
- It is likely that a notional “standalone” competitor to UE may seek a rate of return that exceeds the regulated cost of capital.

These factors indicate that the standalone costs will exceed the cost of supply estimates on which UE bases its tariff design. It is important to recognise that it is difficult to determine the standalone costs with precision – inevitably a judgement must be made. The results of UE’s modelling is summarised in Table 6.2:

**Table 6-2: Comparison of 2018 Tariff Rates with Existing Estimated "Cost Window"**

| Tariff Code | Tariff Class | Lower Bound "Avoidable Cost" (c/kWh) | 2018 Avg DUOS (Exc GST) (c/kWh) | Upper Bound "Standalone Cost" (c/kWh) |
|---|---|---|---|---|
| Unmet<br>LVS1R<br>LVS2R*<br>LVDed<br>WET2Step*<br>TOD<br>TOD9<br>TODFLEX<br>RESKW1R | Low Voltage Small | 0.39 | 3.20<br>7.20<br>5.60<br>1.93<br>7.20<br>6.22<br>6.22<br>7.20<br>7.20 | 13.81 |
| LVM1R<br>LVM2R5D*<br>LVM2R7D*<br>LVkWTOU*<br>TOU<br>LVMKW1R<br>LVMKWTOU | Low Voltage Medium | 0.45 | 8.29<br>6.92<br>8.03<br>6.61<br>8.03<br>7.26<br>6.03 | 18.80 |
| LVL2R*<br>LVL1R*<br>LVKVATOU | Low Voltage Large | 0.15 | 6.05<br>5.52<br>4.05 | 6.13 |
| HVkVATOU | High Voltage Large | 0.09 | 1.94 | 3.19 |
| SubTkVATOU* | Subtransmission Large | 0.09 | 0.53 | 3.19 |

* Tariff closed to new connections and customers not already taking supply under this tariff

## 6.5. Long Run Marginal Costs

Sections 6.18.5 (f) to (j) of the NER establish the requirement for UE to demonstrate that each tariff is based on the Long Run Marginal Cost (LRMC) of providing network services. UE's revised TSS document submitted to the AER in September 2017 details how UE has addressed the new pricing objective and pricing principles in relation to LRMC calculation methodology and recovery of efficient costs. In its' final decision on the 26th August 2016, the AER endorsed UE's approach to LRMC and indicative pricing levels for tariffs.

**United Energy approach to LRMC signalling for TSS period**

UE will apply an approach to transition customers to tariffs which better reflect the estimated LRMC cost of demand within each customer segment. As part of this transition UE has also taken into account potential customer impacts. In signalling LRMC UE will seek to reflect a balance between the pure LRMC demand signal, recovered via tariff demand component revenue and the desire to minimise year on year customer NUOS impacts and the objectives described in section 6.18.5 (f) to (j) of the NER.

The proposed approach to transition for each tariff class is described briefly as follows;

**Low voltage small residential customers** – UE first introduced a residential demand based tariff in 2015 and in subsequent years has refined the product specification in consultation with stakeholder groups. Throughout the TSS process UE had indicated a preference to commence transition of customers onto demand tariffs from 2017. However, the final decision from the AER determined that transition of customers consuming <40MWh per annum will remain on an "opt in' basis for the balance of the current regulatory period.

A residential tariff with demand components (RESKW1R) will once again be available in 2018. It will target 60% of a customer's DUOS charge to be recovered from demand tariff components. At this level approximately 75% of the calculated LRMC of demand is being recovered from demand tariff components, with the residual revenue being recovered through an anytime energy tariff component. Demand tariff components will be recovered on a $/kW basis.

**Low voltage small business customers** – In accordance with UE's Revised TSS, as endorsed by the AER on the 26th August 2016, eligible customers transitioned to a new tariff with a demand component (LVMKW1R) on 1st January 2017. This initial step targeted 25% of a customer's DUOS charge to be recovered from demand tariff components with a subsequent step up to 50% (of DUOS from demand) from 2019. This level approximates the calculated LRMC of demand with the residual revenue being recovered through an anytime energy tariff. Demand tariff components will be recovered on a $/kW basis. LVMKWTOU continues to be available for customers seeking to "opt in" to a fully cost reflective tariff (i.e.50% of DUoS from demand).

**Large business customers** – As our large customer tariffs already have well established monthly and seasonal demand components our approach will be to use the estimated scaled LRMC demand values to guide tariffs levied on demand components on a $/kVA basis. Residual revenue will be recovered on a TOU energy basis. For this customer class United Energy will be seeking to minimise tariff driven customer impacts for the current TSS period.

## 6.6. Description of price changes

Consistent with the AER 2016-2020 Price Determination, rebalancing has been undertaken of tariffs at the tariff class level.

This rebalancing takes into consideration and is consistent with the Price Determination and tariff policies, balancing the need to:

- recover maximum allowable revenue to recover the efficient costs of operating the network business;
- reduce risk in recovering revenue;
- give pricing signals to customers to provide an incentive for efficient utilisation of the network;
- be consistent with Pricing Principles and Cost of Supply Model where each tariff is;
  - above the avoidable cost of serving distribution customers;
  - below the cost of providing the service on a standalone basis;
- signal the impact of additional usage on future investment costs;
- recover NUoS from customers in proportion to the services provided - classified by voltage, demand, and consumption patterns;
- be consistent with UE's tariff strategies;
- be consistent with the UE tariff policy framework.

Given the above considerations, it has been decided not to implement the average price movement across all tariffs as this would be inconsistent with the pricing principles which require signalling of the impact of additional usage on future investment costs. Accordingly some rebalancing has been undertaken at the tariff class level.

# 7. Transmission Cost Recovery Tariffs

## 7.1. Transmission Cost Recovery Tariff Methodology

TUoS tariffs are designed to recover the transmission costs (grid fees) incurred by the distribution business. The TUoS tariff structure is compatible with the DUoS tariff structure. This structure has been maintained in order to allow the NUoS tariff to be determined by simply adding the DUoS and TUoS rates. The application of TUoS rates are designed to best reflect the underlying cost of grid fees (i.e. Peak Energy and demand related charges such as the summer demand incentive and rolling demand charges).

## 7.2. Transmission Use of System Charges and Under/Over Recovery Previous Years

As shown by table 7-1 below, the expected TUOS revenue decrease from 2017 to 2018 is -16.2%.

**Table 7-1: Estimated TUOS Revenue Increase ($'m)**

| | 2017 (Est) | 2018 (FC) | Var(%) |
|---|---|---|---|
| Grid Fee Forecast | $108 | $108 | |
| Over/under recovery from previous year | -$6 | $13 | |
| Actual/Allowed Revenue current year (grid fees less over recovery) | $114 | $95 | |
| Estimated Revenue collected | $114 | $95 | -16.2% |

# 8. Customer Tariff Class Assignment and Reassignment

## 8.1. Network Use of System Tariffs

Table 8.1 sets out tariff availability for newly connecting customers.

**Table 8-1: Closed and Open Network Tariffs to new connections**

| Tariff Code | Tariff Open New Connection | Tariff Description | Tariff Class |
|---|---|---|---|
| Unmet | Yes | Unmetered supplies | Low voltage small |
| LVS1R | Yes | Low voltage small 1 rate | |
| LVS2R | No | Low voltage small 2 rate | |
| LVDed[1] | Yes | Dedicated circuit | |
| WET2Step | No | Winter economy tariff | |
| TOD | Yes | Time of Day | |
| TOD9 | Yes | Time of Day 9pm off peak | |
| RESKW1R[2] | Yes | Seasonal demand anytime energy rate | |
| TODFLEX | Yes | Time of Day Flexible | |
| LVM1R[3] | Yes | Low voltage medium 1 rate | Low voltage medium |
| LVM2R5D | No | Low voltage medium 2 rate 5 day | |
| LVM2R7D | No | Low voltage medium 2 rate 7 day | |
| LVkWTOU | No | Low voltage KW time of use | |
| LVkWTOUH | Closed | Low voltage KW time of use – HOT | |
| TOU[3] | Yes | Time of use | |
| LVMKW1R[2,] | Yes | Seasonal Demand anytime energy rate | |
| LVMKWTOU[2, 3] | Yes | Seasonal Demand anytime energy rate | |
| LVL2R | No | Low voltage large 2 rate | Low voltage large |
| LVL1R | No | Low voltage large 1 rate | |
| LVkVATOU | Yes | Low voltage large KVA time of use | |
| HVkVATOU | Yes | High voltage KVA time of use | High voltage large |
| SubTkVATOU | No | Subtransmission KVA time of use | Subtransmission large |

1. LVDed not available to customers with solar PV installed.
2. Not available to customers with dedicated hot water meters
3. Open to new connection where customer consumes >20MWh <160MWh pa

NB: Where the tariff also includes PFIT, a prefix of “F” will apply eg.FLVS1R

**Tariff assignment for New Connections**

The AER's procedures for assigning and reassigning customers to tariff classes for the Victorian DNSPs are set out in appendix D of the AER's Final Decision. These procedures require that in determining the tariff class to which a customer or potential customer will be assigned, or reassigned, UE must take into account one or more of the following factors:

(a) the nature and extent of the customer's usage;

(b) the nature of the customer's connection to the network; and

(c) whether remotely-read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement.

## 8.2. Customers Usage

The table below outlines the customer categories based on energy consumption and maximum demand. The customer category determines the network tariff options.

**Table 8-2: Customer Usage**

| Category | Maximum Demand (kVA) | Annual Energy Consumption (MWh) |
|---|---|---|
| Small | NA | <20 |
| Medium | NA | 20 to 400 |
| Large | >150 and/or | >400 |

#### 8.2.1. Metering and regulatory implications

UE has completed its roll out of advanced interval metering (AMI program) for customers consuming less than 160MWh per annum.

Where single phase customers have an off peak heating load and a LVS1R plus Dedicated tariff combination, a single phase two element AMI enabled meter with contactor will be installed to separately measure the off peak hot water load, which is the same as the current two meters plus time switch meter combination.

Where a customer wishes to receive a feed in tariff, a net interval metering configuration is required to provide a net export energy stream. In this circumstance, a single measurement element will not be able to provide a dedicated measurement for off peak heating load and a Time of Day or a Time of Use network tariff with an off peak component will be assigned as the default.

#### 8.2.2. Tariff Re-assignment

UE's network tariffs contain summer and non-summer components. To minimise potential DUoS cost distortion associated with the seasonal tariffs, a new connection must remain on the assigned/re-assigned network tariff for a minimum of 12 consecutive months unless there is a load or connection characteristic change. Change of network tariff will be prospective. It is important that customers contact retailers to ensure they are well informed about retail and network tariff offerings.

## 8.3 Network options for newly connecting small customers <20MWh pa

For customers who use less than 20MWh per annum, the default and optional tariff combinations for new connections are detailed below.

All new connections and replacement meters will use an AMI interval meter.

**Table 8-3: Default and Tariff Options (Small Customers <20MWh pa)**

| | Default UE Network Tariff from 1 January 2018 | Optional UE Network Tariff from 1 January 2018 if requested* |
|---|---|---|
| **New connections (no solar)** | | |
| - Standard | LVS1R | TOD<br>TOD9<br>TODFLEX<br>RESKW1R |
| - Plus hot water and or slab | LVS1R + Ded | TOD<br>TOD9<br>TODFLEX<br>LVS1R |
| **New Connections (Solar)** | | |
| - Standard | TOD9 | TOD<br>TODFLEX<br>RESKW1R<br>LVS1R |
| - Plus hot water and or slab | TOD9 | TOD<br>TODFLEX<br>LVS1R |

NB: Where a customer is not residential, a new connection must remain on the initial network tariff for a minimum of 12 consecutive months unless there is a load or connection characteristic change.

## 8.4 Network options for newly connecting medium customers >20MWh <400MWh pa

For customers who consume between 20-400MWh per annum, the default and optional tariff combinations for new connections are detailed in tables 8.8 to 8.6 below. In allocating the tariff combinations UE has referenced;

- AMI Tariffs Amendment Order published in the Victorian Government Gazette on the 14th of April 2016.
- AMI Tariffs Amendment Order published in the Victorian Government Gazette on the 12th of September 2017.
- UE's revised TSS submitted to the AER on the 5th September 2017 pending approval by 30th November 2017.

**Table 8-4: Default Tariff Options (Medium Customers >20-<40MWh pa)**

| | Default UE Network Tariff from 1 January 2018 | Optional UE Network Tariff from 1 January 2018 if requested |
|---|---|---|
| **New connections (no Solar)** | | |
| - Standard | LVM1R | TOU<br>LVMKW1R<br>LVMKWTOU |
| **New Connections (Solar)** | | |
| - Standard | TOU | LVM1R<br>LVMKW1R<br>LVMKWTOU |

Further information on the above tariffs and tariff eligibility is provided in the following section.

The TODFLEX tariff is applicable to residential customers only with an AMI meter. On occasion, a residential customer may consume greater than 20MWh. In these cases, these customers are deemed "medium" but can remain eligible for either tariff class.

**Table 8-5: Default Tariff Options (Medium Customers >40-<160MWh pa)**

| | Default UE Network Tariff from 1 January 2018 | Optional UE Network Tariff from 1 January 2018 if requested |
|---|---|---|
| **New connections (no Solar)** | | |
| - Standard | LVMKW1R* | LVM1R<br>TOU<br>LVMKWTOU |
| **New Connections (Solar)** | | |
| - Standard | LVMKW1R* | LVM1R<br>TOU<br>LVMKWTOU |

*Customers may opt out of default new connection tariff by notifying their Retailer in accordance with the provisions of the AMI Tariffs Order amendment (12th September 2017). Customer electing to opt out must remain on the optional tariff for a minimum period of 12 months.

**Table 8-6: Default Tariff Options (Medium Customers >160-<400MWh pa)**

| | Default UE Network Tariff from 1 January 2018 | Optional UE Network Tariff from 1 January 2018 if requested |
|---|---|---|
| **New connections (no Solar)** | | |
| - Standard | LVMKW1R | LVMKWTOU |
| **New Connections (Solar)** | | |
| - Standard | LVMKW1R | LVMKWTOU |

## 8.5 Default Network Tariffs for New Connections

The following section provides information on the default tariffs for new connections and the applicable tariff eligibility:

### Low Voltage Small 1 Rate (LVS1R):

- This tariff is currently available to new connections
- Customers must consume <20 MWh/pa.
- Includes a daily standing charge.
- Includes a summer and non-summer peak energy charge.
- Customers can make savings by reducing their energy consumption during summer months. Usage during non-summer is cheaper.
- Where the customer is residential with an AMI meter installed, tariff re-assignment rules apply as per section 8.2.3 and section 8.3 of the 2018 United Energy Pricing Proposal.
- Summer is defined as 1 November to 31 March.

### Low Voltage Medium Demand 1 Rate (LVMKW1R):

- Customers must be >40 & <400 MW/h per annum
- Requires an AMI meter.
- Available from 2017
- No standing charge.

- Summer demand charge (1st December to 31st March) based on monthly maximum demand between 10am and 6pm on work days.
- Non summer demand charge (1st April to 30th November) based on monthly maximum demand occurring between 10am and 6pm on work days.
- Minimum monthly chargeable demand of 1.5KW.
- Flat energy rate applies for all periods.
- Transitional (partially cost reflective) demand based tariff available on an assigned basis from 2017 for >40MWh per annum customers. Fully cost reflective from 2019.
- Customers in the >40-<160MWh pa range can opt out via notification to their Retailer under the provisions of the amended AMI Tariffs Order (12th September 2017). Customers who opt out must remain on the alternative tariff for a minimum period of 12 months.

### Low Voltage Medium Demand (LVMKWTOU):

- Customers must be >20 & <400 MW/h per annum
- Requires an AMI meter.
- Available from 2016
- No standing charge.
- Summer demand charge (1st December to 31st March) based on monthly maximum demand between 10am and 6pm on work days.
- Non summer demand charge (1st April to 30th November) based on monthly maximum demand occurring between 10am and 6pm on work days.
- Minimum monthly chargeable demand of 1.5KW.
- Flat energy rate applies for all periods.
- Fully cost reflective demand based tariff available on opt in basis from 2016.

### Low Voltage Dedicated (LVDED):

- This tariff is only available in conjunction with the LVS1R and LVM1R tariffs for new connections.
- Tariff not available for re-assignments
- Customer must have a dedicated circuit connected to a controlled electric hot water service and/or storage space heating.

- Requires a separately metered dedicated circuit controlled by UE by means of time switch or other means.
- Is a dedicated off peak charge that applies for a maximum of 7 hours during the off peak period.
- The Off Peak period is 11pm to 7am local time.
- All load is controlled by the meter. Note, if there are any controlled load boosts during peak periods, these will be charged the peak tariff rate.
- This tariff is not available to New Customers with embedded generation or existing customers that install embedded generation.

**Time Of Day (TOD):**

- Customers to consume <20MWh/annum
- Requires an interval meter.
- Includes a seasonal peak energy charge. Customers can make savings by reducing their energy consumption during the peak periods (3pm-11pm Local Time workdays).
- Non-Summer Peak energy charge is lower than Summer Peak energy charge to encourage heating usage.
- Includes a seasonal shoulder energy charge. Customers can make savings by reducing their energy consumption during the shoulder periods (7am-3pm Local Time workdays).
- Non-Summer shoulder energy charge is lower than Summer Shoulder energy charge to encourage heating usage.
- Off-peak energy is all day weekends and public holidays and 11pm to 7am Local Time workdays. Usage during off peak times is cheaper than peak times.
- Includes a daily Standing Charge
- Where the customer is residential with an AMI meter installed, tariff re-assignment rules apply as per section 8.2.3 and section 8.3 of the 2018 United Energy Pricing Proposal.
- Summer is defined as 1 November to 31 March.

## Time Of Day 9pm Off Peak (TOD9):

- Customers to consume <20MWh/annum
- Requires an interval meter.
- Includes a seasonal peak energy charge. Customers can make savings by reducing their energy consumption during the peak periods (3pm-9pm Local Time workdays).
- Non-Summer Peak energy charge is lower than Summer Peak energy charge to encourage heating usage.
- Includes a seasonal shoulder energy charge. Customers can make savings by reducing their energy consumption during the shoulder periods (7am-3pm Local Time workdays).
- Non-Summer shoulder energy charge is lower than Summer Shoulder energy charge to encourage heating usage.
- Off-peak energy is all day weekends and public holidays and 9pm to 7am Local Time workdays. Usage during off peak times is cheaper than peak times.
- Includes a daily Standing Charge
- Where the customer is residential with an AMI meter installed, tariff re-assignment rules apply as per section 8.2.3 and section 8.3 of the 2018 United Energy Pricing Proposal.
- Summer is defined as 1 November to 31 March.

## Time Of Day Flexible (TODFLEX):

- Customers must be residential.
- Requires an AMI meter.
- Includes a seasonal peak energy charge. Customers can make savings by reducing their energy consumption during the peak periods. The peak energy period is between 3pm and 9pm Local Time workdays inclusive of public holidays on weekdays.
- Non-Summer Peak energy charge is lower than Summer Peak energy charge to encourage heating usage.
- Includes a seasonal shoulder energy charge. Customers can make savings by reducing their energy consumption during the shoulder periods. Shoulder energy is 7am-3pm and 9pm-10pm Local Time workdays including public holidays, and 7am-10pm weekends.
- Non-Summer shoulder energy charge is lower than Summer Shoulder energy charge to encourage heating usage.
- Off-peak energy is 10pm to 7am Local Time workdays including public holidays and weekends. Usage during off peak times is cheaper than peak times.

- Includes a daily Standing Charge
- Tariff re-assignment rules apply as per section 8.2.3 and section 8.3 of the 2018 United Energy Pricing Proposal.
- Summer is defined as the commencement of daylight savings (early October) to the finish of daylight savings (early April).

**Time Of Use (TOU):**

- Customers must consume >20 and <160MWh/annum.
- This tariff is available to new connections and as an opt out alternative to cost reflective tariffs.
- Requires an interval meter.
- Includes a seasonal peak energy charge. Customers can make savings by reducing their energy consumption during the peak periods (7am-11pm Local Time workdays).
- Off-peak energy is all day weekends and public holidays and 11pm to 7am Local Time workdays. Usage during off peak times is cheaper than peak times.
- Includes a Summer Demand Incentive Charge measured at maximum kW per billing period between 2pm and 7pm local time workdays in summer. This empowers customers to make savings by altering the time of use of their consumption away from 2pm to 7pm Local Time workdays in summer.
- Once on this tariff, non-residential customers cannot move onto another tariff for a minimum period of 12 months.
- Summer is defined as 1 November to 31 March.

**Residential Demand 1 Rate (RESKW1R):**

- Customers must be <20MW/h per annum
- Requires an AMI meter.
- Has been available from 2016
- No standing charge.
- Summer demand charge (1st December to 31st March) based on monthly maximum demand between 3pm and 9pm on work days.
- Non summer demand charge (1st April to 30th November) based on monthly maximum demand occurring between 3pm and 9pm on work days.
- Minimum monthly chargeable demand of 1.5KW.

- Flat energy rate applies for all periods.
- Fully cost reflective demand based tariff available on-opt in basis.

**Low Voltage kVA Time Of Use (LVkVATOU):**

- Customers must be in "large" category (>400MWh and/or >150kVA).
- Must have a Type 1-4 meter measuring kW and kVar on low voltage connection.
- Includes a seasonal peak energy charge. Customers can make savings by reducing their energy consumption during the peak periods (7am-7pm Local Time workdays).
- Includes a Summer Demand Incentive Charge (measured as kVA at maximum kW per billing period). This empowers customers to make savings by altering the time of use of their consumption away from 3pm to 6pm Local Time workdays in summer.
- Off-peak energy is all day weekends and public holidays and 7pm to 7am Local Time workdays. Usage during off peak times is cheaper than peak times.
- The peak rolling demand is 7am - 7pm Local Time workdays and is measured as kVA at maximum kW. The minimum rolling demand applicable is 150 kVA.
- Once on this tariff, customers cannot move onto another tariff for a minimum period of 12 months.
- Summer is defined as 1 November to 31 March.

**High Voltage kVA Time Of Use (HVkVATOU):**

- Customers must be in "large" category (>400MWh and/or >1,150kVA).
- Must have a Type 1-4 meter measuring kW and kVar on high voltage connection.
- Includes a seasonal peak energy charge. Customers can make savings by reducing their energy consumption during the peak periods (7am to 7pm local time workdays).
- Includes a Summer Demand Incentive Charge (measured as kVA at maximum kW per billing period). This empowers customers to make savings by altering the time of use of their consumption away from 3pm to 6pm local time workdays in summer.
- Off-peak energy is all day weekends and public holidays and 7pm to 7am local time workdays. Usage during off-peak times is cheaper than peak times.
- The peak rolling demand is 7am to 7pm local time workdays and is measured as kVA at maximum kW. The minimum rolling demand applicable is 1150 kVA.
- Once on this tariff, customers cannot move onto another tariff for a minimum period of 12 months. .
- Summer is defined as 1 November to 31 March.

## 8.6 Jurisdictional Scheme: Feed in Tariff schemes

The Victorian Government introduced a premium feed in tariff policy in November 2009. A premium feed in tariff (PFIT) was available to residential and commercial customers consuming less than 100 MWh/annum who installed up to 5 kW of solar panels and had net interval metering. However, upon reaching 100MW of installed solar capacity across Victoria in November 2011, the Minister declared the end of the scheme. As a replacement, the Government introduced the Transitional Feed in Tariff (TFIT). The TFIT scheme closed to new customers as at 31 December 2012, and there is no new Distributor administered scheme to replace PFIT/TFIT.

The TFIT scheme ended on 31 December 2016 with all TFIT customers transitioning on to the flexible FIT scheme administered by the retailers.

UE administers the rebates under the jurisdictional scheme and seeks to recover the cost of the PFIT/TFIT credits by recovering on a fixed rate per customer basis. For 2018 the annual recovery is $19.74 per customer which represents a decrease of $3.1 from the prior year.

### 8.6.1 Jurisdictional Scheme Amounts

Table 8.5 outlines the jurisdictional charges and correction factors applicable to UE in 2018. The correction factor represents the accumulated under recovery of revenue versus rebates paid since the commencement of the scheme.

**Table 8-5: Jurisdictional PFIT Scheme Amounts (Real $'000)**

| Jurisdictional PFIT/TFIT Scheme Amounts ($'000) | | | |
|---|---|---|---|
| | 2016 actual | 2017 estimate | 2018 forecast |
| Revenue from PFIT/TFIT charges | $ 20,899,860 | $ 14,901,266 | $ 13,393,072 |
| PFIT/TFIT rebates paid | $ 20,584,875 | $ 13,652,725 | $ 15,058,465 |
| Correction factor | | | |

### 8.6.2 Calculation PFIT Rebate Costs applicable to Jurisdictional revenue forecast

The following table outlines the actual and estimated PFIT rebate costs from 2016 to 2018:

**Table 8-6: PFIT Rebates**

| PFIT Rebate Cost | 2016 actual | 2017 estimate | 2018 forecast |
|---|---|---|---|
| PFIT Rebate $/kWh exported | $ 0.60 | $ 0.60 | $ 0.60 |
| Customers on PFIT (31 Dec) | 18,231 | 18,231 | 18,231 |
| Customers on PFIT (average for year) | 18,231 | 18,231 | 18,231 |
| kWh exported | 24,829,275 | 24,761,677 | 24,777,038 |
| KWh per customer | 1,362 | 1,358 | 1,359 |
| PFIT rebate cost ($'000) | $ 14,898 | $ 14,857 | $ 14,866 |

#### 8.6.3 Calculation TFIT Rebate Costs applicable to Jurisdictional revenue forecast

The following table outlines the actual TFIT rebate costs from 2016 to 2018:

**Table 8-7: TFIT Rebates**

| TFIT Rebate Cost | 2016 actual | 2017 estimate | 2018 forecast |
|---|---|---|---|
| TFIT Rebate $/kWh exported | $ 0.25 | | |
| Customers on TFIT (31 Dec) | 13,667 | | |
| Customers on TFIT (average for year) | 13,667 | | |
| kWh exported | 21,821,253 | | |
| KWh per customer | 1,597 | | |
| TFIT rebate cost ($'000) | $ 5,455 | | |

The Transitional Feed-in Tariff (TFIT) closed to new customers on 31st December 2012 and the scheme ended on 31st December 2016. Therefore, TFIT customers ceased to receive the distributor administered feed in tariff rate of $0.25/kWh on 31 December 2016. From this date customers transitioned to Retailer administered incentive feed in tariff schemes.

## 8.7 Tariff Reassignments for Existing Customers

**Table 8-8: Tariff Reassignment for Existing Customers**

| Meter Type | <20MWh | >20MWh |
|---|---|---|
| Basic | LVS1R | LVM1R |
| Interval | LVS1R<br>TOD<br>TOD9 | LVM1R<br>TOU |
| AMI | LVS1R<br>TOD<br>TOD9<br>TODFLEX (residential only)<br>RESKW1R | LVM1R<br>TOU<br>TODFLEX (residential only)<br>LVMKWTOU / LVMKW1R |
| Solar | LVS1R<br>TOD<br>TOD9<br>TODFLEX (residential only with AMI enabled meter)<br>RESKW1R | LVM1R<br>TOU<br>TODFLEX (residential only with AMI enabled meter)<br>LVMKWTOU / LVMKW1R |

UE's network tariffs contain summer and non-summer components. To avoid tariff arbitrage, an existing non-residential customer must remain on a re-assigned/assigned network tariff for a minimum of 12 consecutive months unless there is a load or connection characteristic change. It is important that customers contact retailers to ensure they are well informed about retail and network tariff offerings.

Additional reassignment rules are indicated below;

- Change of network tariff will be prospective. Limited retrospectivity may be sought to align to a retail transfer.

## 8.8 UE's system of assessing and reviewing a customer's charges

As noted in Section 2.4 of this Pricing Proposal, the AER's final decision requires UE to provide for an appropriate system of assessment and review of the basis on which a customer is charged. In accordance with the AER's requirements, UE's system of assessment and review involves the following three-step process:

- Step 1: UE critically examines its draft annual tariff changes to identify customers that are likely to experience price changes that are materially different to the tariff average. It is noted that such variations may occur if a customer's load profile contrasts sharply with typical tariff customer and where tariff changes differ across tariff components. UE will amend its draft tariff proposals where appropriate, having regard to the principles that guide tariff prices.
- Step 2: Following UE's annual tariff review, UE contacts customers where the current tariff is inappropriate for the customer's load profile or would likely to result in a substantial increase in network charges. UE would identify alternative network options for the customer's consideration or measures to assist the customer in reducing its network charges.
- Step 3: Where a customer or customer's retailer contacts UE regarding the basis on which a customer is charged, UE will identify alternative network options or measures to assist the customer in reducing network charges. However, UE notes that steps 1 and 2 properly executed should minimise, if not eliminate, the number of contacts from customers and retailers regarding inappropriately high network charges.

In addition to the above steps, UE will be guided by the Rules (NER s6.18.5) in determining the appropriate course of action to review and assess customers' usage for tariff applicability. In this regard, UE has outlined a method to transition customers to meet the new pricing objective and pricing principles of cost reflectivity as outlined in our TSS document.

# 9. Alternative Control Services

## 9.1. Regulatory Requirements

A number of the Rule requirements in clause 6.18 relating to direct control services are applicable to both standard control services and alternative control services.

## 9.2. Pricing principles

Clause 6.18.5 of the Rules sets out the pricing principles that must be complied with in respect of each tariff class, including a tariff class within the classification of alternative control services.

## 9.3. Charging parameters for alternative control services – fee based

The price path for the regulatory period is CPI + X, where X for each year is defined in table 16.1 of the AER Final Decision (May 2016). The table below contains the approved fee based alternative control services charges as per the AER Final Decision (May 2016) updated with the June 2017 CPI + X.

**Table 9-1: Fee based alternative control services prices for 2018**

| Fee based services | 2018 Price (ex GST) |
|---|---|
| ***Field Officer Visits – Existing Premises*** | |
| Special read (basic meter) | $22.00 |
| Special read (interval meter) | $22.00 |
| Re-energise (fuse insert) - BH (unit rate) | $46.86 |
| De-energise (fuse removal) - BH (unit rate) | $46.86 |
| Express move in re-energise (fuse insert) – BH (unit rate) | $70.64 |
| Re-energise (fuse insert) – AH (unit rate) | $83.15 |
| Express move in re-energise (fuse insert) – AH (unit rate) | $130.76 |
| De-energise at point of attachment (pole/pit/premise) – BH (unit rate) | $362.19 |
| ***Temporary Supplies (excl inspection) – Coincident Disconnection where UE is the Responsible Person*** | |
| Standard single phase – BH (unit rate) | $473.22 |
| Multi phase to 100A – BH (unit rate) | $473.02 |
| Standard single phase – AH (unit rate) | $722.70 |
| Multi phase to 100A – AH (unit rate) | $722.50 |
| *Temporary Supplies (excl inspection) – where UE is Not the Responsible Person* | |
| Single Phase Servicing and Energisation only – BH (unit rate) | $439.14 |
| Multi Phase Servicing and Energisation only – BH (unit rate) | $439.14 |

| Fee based services | 2018 Price (ex GST) |
|---|---|
| Single Phase Servicing and Energisation only – AH (unit rate) | $722.70 |
| Multi Phase Servicing and Energisation only – AH (unit rate) | $722.70 |
| ***New Connection where UE is the Responsible Person*** | |
| Single phase single element – BH (unit rate) | $473.22 |
| Single phase two element (off peak) – BH (unit rate) | $473.22 |
| Three phase direct connected – BH (unit rate) | $473.03 |
| Single phase single element – AH (unit rate) | $722.70 |
| Single phase two element (off peak) – AH (unit rate) | $722.70 |
| Three phase direct connected – AH (unit rate) | $722.50 |
| Routine new connections – three phase current transformer connected – BH | Quoted |
| Routine new connections – three phase current transformer connected – AH | Quoted |
| ***New Connections – where UE is Not the Responsible Person*** | |
| Single phase single element – BH (unit rate) | $439.14 |
| Single phase two element (off peak) – BH (unit rate) | $439.14 |
| Three phase direct connected – BH (unit rate) | $439.14 |
| Single phase single element – AH (unit rate) | $722.70 |
| Single phase two element (off peak) – AH (unit rate) | $722.70 |
| Three phase direct connected – AH (unit rate) | $722.70 |
| Routine new connections – three phase current transformer connected - BH | Quoted |
| Routine new connections – three phase current transformer connected - AH | Quoted |
| ***Service Vehicle Visits (without inspection)*** | |
| Service truck – first 30 minutes – BH (unit rate) | $336.20 |
| Each additional 15 minutes – BH (unit rate) | $69.52 |
| Wasted service truck visit - BH (unit rate) | $291.61 |
| Service truck – 2 hrs min – AH (unit rate) | $744.07 |
| Each additional 15 minutes – AH (unit rate) | $96.41 |
| Wasted service truck visit – AH (unit rate) | $744.07 |
| Truck Visit + 1x additional 15 mins BH (unit rate) | $405.73 |
| Truck Visit + 2x additional 15 mins BH (unit rate) | $475.25 |

| Fee based services | 2018 Price (ex GST) |
|---|---|
| Truck Visit + 3x additional 15 mins BH (unit rate) | $544.76 |
| Truck Visit + 4x additional 15 mins BH (unit rate) | $614.29 |
| Truck Visit + 5x additional 15 mins BH (unit rate) | $683.80 |
| Truck Visit + 6x additional 15 mins BH (unit rate) | $753.31 |
| Truck Visit + 1x additional 15 mins AH (unit rate) | $840.48 |
| Truck Visit + 2x additional 15 mins AH (unit rate) | $936.90 |
| Truck Visit + 3x additional 15 mins AH (unit rate) | $1,033.32 |
| Truck Visit + 4x additional 15 mins AH (unit rate) | $1,129.73 |
| Truck Visit + 5x additional 15 mins AH (unit rate) | $1,226.14 |
| Truck Visit + 6x additional 15 mins AH (unit rate) | $1,322.56 |
| ***Meter Equipment Test*** | |
| Single phase | $261.94 |
| Single phase (each additional meter) | $125.69 |
| Multi phase | $261.62 |
| Multi phase (each additional meter) | $125.69 |
| ***Remote AMI Services*** | |
| Remote Meter Configuration | $62.48 |
| Remote Special Meter Reading | $0.84 |
| Remote Re-Energise | $10.55 |
| Remote de-Energise | $10.55 |

**Table 9-2: Charge out rates for quoted alternative control services 2018**

| Description | 2018 Rate (ex GST) |
|---|---|
| Field worker - one person - BH | $128.39 |
| Field worker - one person - AH | $182.34 |
| Field worker - one person plus vehicle - BH | $150.51 |
| Field worker - one person plus vehicle - AH | $204.46 |
| Administration - BH | $99.20 |
| Senior engineer - BH | $189.09 |
| Project planner - BH | $189.09 |

# 10. Charging parameters for alternative control services - Metering Services

There are only two charging parameters within the alternative control services metering services tariff class: customer numbers and exit fee transactions.

Meter provision services are charged to each alternative control services network customer on a $/day basis, so the relevant charging parameter is the number of customer days. Meter services exit fee transactions will be charged on an as incurred basis, so the relevant charging parameter is the number of exit fee transactions. As per the AER Final Decision (May 2016) the charging parameters for each tariff within the alternative control services - metering services tariff class are set out in the tables below.

## 10.1 Advanced Metering Infrastructure Charges (AMI) <160Mwh customers

The AER's framework and approach for standard metering services for small customers (those who consume less than 160 MWh per annum) is to regulate these as prescribed services, with the charges for these services set separately to distribution use of system charges.

**Table 10.1 Charges for AMI metering charges of single and three phase meters.**

| AMI metering charges per meter per annum | 2018 Price (ex GST) |
|---|---|
| Single phase non off peak meter | $57.58 |
| Single phase off peak meter* | $57.58 |
| Three phase direct connected meter | $64.93 |
| Three phase current transformer connected meter | $68.85 |

**Note:** * A single phase off peak accumulation meter but has one logical meter for charging but has two physical single phase meters.

## 10.2 Prescribed Metering Service Charge

The metering data services for public lighting are services provided exclusively to public lighting customers, such as retailers, municipal councils and Vic Roads.

**Table 10.2 Meter data services (Public lighting)**

| Meter data services | 2018 Price (ex GST) |
|---|---|
| Unmetered supplies – Public lighting (per light) | $1.347 |

## 10.3 Metering Exit Fees

An exit fee applies when a customer chooses to replace a regulated meter installed under the derogation with a competitively sourced meter.

**Table 10.3 Metering exit fees**

| Metering exit fees | 2018 Price (ex GST) |
|---|---|
| Single phase single element meter | $387.88 |
| Single phase single element meter with contactor | $392.45 |
| Three phase direct connected meter | $436.60 |
| Three phase current transformer connected meter | $578.14 |

# 11. Public Lighting

The table below contains the approved public lighting charges as per the AER Final Decision (May 2016) Attachment 16 – Alternative control services updated with the June 2017 CPI and approved real pre-tax WACC.

**Table 11-1: Alternative Control Services - Public Lighting Charges**

| Light Type | 2018 Price/light pa (ex GST) |
|---|---|
| Mercury Vapour 80 watt | 56.87 |
| Sodium High Pressure 150 watt | 75.91 |
| Sodium High Pressure 250 watt | 72.70 |
| Fluorescent 2x20 watt | 73.36 |
| Fluorescent 3x20 watt | 73.36 |
| Mercury Vapour 50 watt | 84.17 |
| Mercury Vapour 125 watt | 84.17 |
| Mercury Vapour 250 watt | 66.16 |
| Mercury Vapour 400 watt | 91.61 |
| Mercury Vapour 700 watt | 91.61 |
| Sodium High Pressure 70 watt | 124.54 |
| Sodium High Pressure 100 watt | 83.51 |
| Sodium High Pressure 400 watt | 91.61 |
| Metal Halide 70 watt | 102.48 |
| Metal Halide 100 watt | 102.48 |
| Metal Halide 150 watt | 102.48 |
| Metal Halide 250 watt | 98.15 |
| Metal Halide 400 watt | 98.15 |
| T5 2X14W | 32.65 |
| Twin 24W Fluorescent | 32.65 |
| Compact Fluoro 32W | 32.65 |
| Compact Fluoro 42W | 32.65 |

# Appendix A: Tariff Model

# Appendix B: Tariff Summary

# Appendix C: Public Lighting Model

# Appendix D: Alternative Control Services Model

# Appendix E: Metering Exit Fees Model

# Appendix F: Indicative Rate Tables (2019 & 2020)

# Appendix G: Audit Report

Deloitte.

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# Agreed Upon Procedures Report in Report in Relation to the to the United Energy Distribution Pty Ltd Tariff Submission for 2018

To: The Directors of United Energy Distribution Pty Ltd

**Report of Factual Findings**

We have performed the procedures agreed with you to report factual findings for the purpose of assisting you and the Australian Energy Regulator ("AER") with your submission of data contained within Tariff Data Templates ("TDT's") to the AER. The procedures performed are detailed in the terms of the engagement on the 25 September 2017 and described below with respect to the Tariff Submission of United Energy Distribution Pty Ltd ("United Energy") for inclusion in the 2018 Pricing Proposal submitted to the AER.

*The Director's Responsibility for the Procedures Agreed*

The directors of United Energy are responsible for the adequacy or otherwise of the procedures agreed to be performed by us. You and the AER are responsible for determining whether the factual findings provided by us, in combination with any other information obtained, provide a reasonable basis for any conclusions which you and the AER wish to draw on the subject matter.

*Our Responsibility*

Our responsibility is to report factual findings obtained from conducting the procedures agreed. We conducted the engagement in accordance with Standard on Related Services ASRS 4400 Agreed-Upon Procedures Engagements to Report Factual Findings. We have complied with ethical requirements equivalent to those applicable to Other Assurance Engagements, including independence.

The agreed-upon procedures do not constitute either a reasonable assurance (audit) or limited assurance (review) engagement in accordance with the Auditing and Assurance Standards Board (AUASB) standards, and as such, we do not express any conclusion and provide no assurance on the data contained within Tariff Data Templates ("TDT's") for inclusion in the 2018 Pricing Proposal submitted to the AER. Had we performed additional procedures or had we performed a reasonable or limited assurance engagement in accordance with AUASB standards, other matters might have come to our attention that would have been reported to you.

*Factual Findings*

The procedures were performed solely for the Purpose as specified above. The procedures performed and the factual findings obtained are as follows:

Liability limited by a scheme approved under Professional Standards Legislation.
Member of Deloitte Touche Tohmatsu Limited

Deloitte.

<table>
<tr><th>Procedures Performed</th><th>Factual Findings</th></tr>
<tr><td>1. We will check that the Revenue from DUOS charges reported in Attachment A of the 2018 Tariff Submission agree with those included in Annual RIN Financial Information Template 8.1 (Table 1 Income Statement) of the 31 December 2016 United Energy RIN Reporting Templates (and include an explanation of any reconciling items between current and previously reported revenue from DUOS charges).</td><td>
<table>
<tr><th>Item</th><th>Tariff Submission</th><th>Per RIN</th><th>Difference</th></tr>
<tr><td>Revenue from DUOS charges</td><td>370,195,702</td><td>373,292,500</td><td>(3,096,798)</td></tr>
</table>
The total Revenue from DUOS Charges for t-2 listed in Attachment A of the 2018 Tariff Submission is $3,096,798 lower than the amount of revenue included in United Energy's RIN Financial Information Template 8.1 (Table 1 Income Statement) for 31 December 2016.
The difference primarily relates to:
<ul>
<li>$2,590,924 of revenue included in the RIN, but not included in the Tariff Submission as it relates to prior period consumption</li>
<li>$586,989 of revenue included in the RIN from unmetered activities, but not included in the Tariff Submission as these amounts are manual adjustments made in the accounting system based on estimated consumption (not billed based on consumption read by the meters)</li>
</ul>
</td></tr>
<tr><td>2. We will check that the TUOS charges, Transmission connection fees and Cross boundary network charges listed in Attachment A of the 2018 Tariff Submission agree with those included in Annual RIN Financial Information Template 9.5 (Table 1 TUOS charges AEMO – Table 3 Cross Boundary Network Charges) of the 31 December 2016 United Energy RIN Reporting Templates (and include an explanation of any reconciling items between current and previously reported charges).</td><td>
<table>
<tr><th>Item</th><th>Tariff Submission</th><th>Per RIN</th><th>Difference</th></tr>
<tr><td>TUOS charges</td><td>96,488,880</td><td>96,488,880</td><td>-</td></tr>
<tr><td>Transmission connection fees</td><td>13,094,346</td><td>13,094,346</td><td>-</td></tr>
<tr><td>Cross boundary network charges</td><td>(1,294,459)</td><td>(184,688)</td><td>(1,109,771)</td></tr>
</table>
There is no difference between the TUOS charges and Transmission connection fees listed in Attachment A of the 2018 Tariff Submission from those included in the Annual RIN Financial Information Template 9.5 (Table 1 TUOS charges AEMO and Table 2 Transmission Connection Fees) of the 31 December 2016 United Energy RIN Reporting Templates.
The amount of Cross Boundary Network charges reported in Attachment A of the Tariff Submission is $1,109,771 more than that reported in the RIN Financial Information Template 9.5 (Table 3 Cross Boundary Network Charges) of the 31 December 2016 United Energy RIN Reporting Template.
Cross Boundary Network Charges are only recognised when the amount has been finalised and billed to/from United Energy. The difference is attributable to $1,479,147 of net credit notes issued to AusNet in September 2017, relating to the 12 month period ended 30 June 2015. As this information was not available at the time the 31 December 2016 United Energy RIN Reporting Templates were prepared, the full charges were previously not recognised.
This is partially offset by a correction of the amount reported in the 2016 RIN, where $184,688 was reported as a negative (payable), when it represented a positive (receivable) amount.
</td></tr>
</table>

<table>
<tr><th>Procedures Performed</th><th>Factual Findings</th></tr>
<tr><td>3. We will check that the Payments to embedded generators listed in Attachment A of the 2018 Tariff Submission agree with those included in the Annual RIN Financial Information Template 9.5 (Table 4 Payments To Embedded Generators) of the 31 December 2016 United Energy RIN Reporting Templates (and include an explanation of any reconciling items between current and previously reported charges).</td><td>
<table>
<tr><th>Item</th><th>Tariff Submission</th><th>Per RIN</th><th>Difference</th></tr>
<tr><td>Payments to embedded generators</td><td>367,249</td><td>367,249</td><td>-</td></tr>
</table>
The Payments to embedded generators listed in Attachment A of the 2018 Tariff Submission agree to those included in RIN Financial Information Template 9.5 (Table 4 Payments To Embedded Generators) of the 31 December 2016 United Energy RIN Reporting Templates.</td></tr>
<tr><td>4. We will check that the total submitted count of public lights listed in Attachment A of the 2018 Tariff Submission agree with those included in Annual RIN Information Template 4.1 (Table 4 Public Lighting Metrics By Tariff) of the 31 December 2016 United Energy RIN Reporting Templates (and include an explanation of any reconciling items between current and previously reported count of public lighting).</td><td>
<table>
<tr><th>Item</th><th>Tariff Submission</th><th>Per RIN</th><th>Difference</th></tr>
<tr><td>Count of public lights</td><td>120,358</td><td>120,358</td><td>-</td></tr>
</table>
The count of public lighting per Attachment A of the 2018 Tariff Submission agrees to that included in the Annual RIN Non-Financial Information Template 4.1 (Table 4 Public Lighting Metrics By Tariff) of the 31 December 2016 United Energy RIN Reporting Templates.</td></tr>
<tr><td>5. We will check that the Premium Feed-in Tariff ("PFIT") and Transitional Feed-in Tariff ("TFIT") rebate costs listed in Attachment A of the 2018 Tariff Submission agree with those included in Annual RIN Financial Information Template 7.10 (Table 1 Jurisdictional Scheme payments) of the 31 December 2016 United Energy RIN Reporting Templates (and include an explanation of any reconciling items between current and previously reported rebates).</td><td>
<table>
<tr><th>Item</th><th>Tariff Submission</th><th>Per RIN</th><th>Difference</th></tr>
<tr><td>PFIT</td><td>12,466,347</td><td>12,466,347</td><td>-</td></tr>
<tr><td>TFIT</td><td>4,858,419</td><td>4,858,419</td><td>-</td></tr>
</table>
The PFIT and TFIT rebate costs reported in Attachment A of the 2018 Tariff Submission agree to those included in the RIN Financial Information Template 7.10 (Table 1 Jurisdictional Scheme payments) of the 31 December 2016 United Energy RIN Reporting Templates.</td></tr>
</table>

**Deloitte.**

<table>
<tr><th>Procedures Performed</th><th>Factual Findings</th></tr>
<tr>
<td>6. We will check that the F Factor rebate costs "unders and overs account" included in the 2018 Tariff Submission agrees with the AER approved F Factor pass through tariff for CY2016 and the F Factor included in Benchmarking RIN Financial Information Template 3.1 (Table 3 Revenue/penalties allowed/deducted through incentive schemes) of the 31 December 2016 United Energy RIN Reporting Templates (and include an explanation of any reconciling items between current and previously reported rebates).</td>
<td>
<table>
<tr><th>Item</th><th>Tariff Submission</th><th>Per RIN</th><th>Difference</th></tr>
<tr><td>F-Factor</td><td>(2,289,171)</td><td>(2,308,582)</td><td>19,410</td></tr>
</table>
There is a $19,410 difference between the F Factor rebate costs "unders and overs account" included in the 2018 Tariff Submission and the F Factor included in the Benchmarking RIN Template 3.1 (Table 3 Revenue/penalties allowed/deducted through incentive schemes) of the 31 December 2016 United Energy Benchmarking RIN Reporting Templates.
As the F Factor rebate costs "unders and overs account" is recovered through DUOS, this F Factor amount has been adjusted proportionately for the difference in the DUOS revenue reported in the Tariff submission compared to the Benchmarking RIN.
</td>
</tr>
</table>

*Restriction on Distribution and Use of the Report*

This report is intended solely for the use of United Energy and the AER for the purpose set out above. As the intended user of our report, it is for you and the other intended users to assess both the procedures and our factual findings to determine whether they provide, in combination with any other information you and the AER have obtained, a reasonable basis for any conclusions which you wish to draw on the subject matter. As required by ASRS 4400, distribution of this report is restricted to those parties that have agreed the procedures to be performed with us and have been identified in the terms of the engagement (since others, unaware of the reasons for the procedures, may misinterpret the results).

Our report may be relied upon by United Energy for the purpose set out above only pursuant to the terms of our engagement letter dated 25 September 2017.

Accordingly, we expressly disclaim and do not accept any responsibility or liability to any other party for any consequences of reliance on this report for any purpose.

DELOITTE TOUCHE TOHMATSU

DELOITTE TOUCHE TOHMATSU

Samuel Vorwerg
Partner
Chartered Accountants
Melbourne, 28 September 2017