Attachment 7.3.5

Energy & Customer Numbers Forecast - 2017

Access Arrangement Information

2 October 2017

Access Arrangement Information (AAI) for the period
1 July 2017 to 30 June 2022

westernpower

Energy & Customer Numbers Forecast

2017

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Prepared by: Ben Jones

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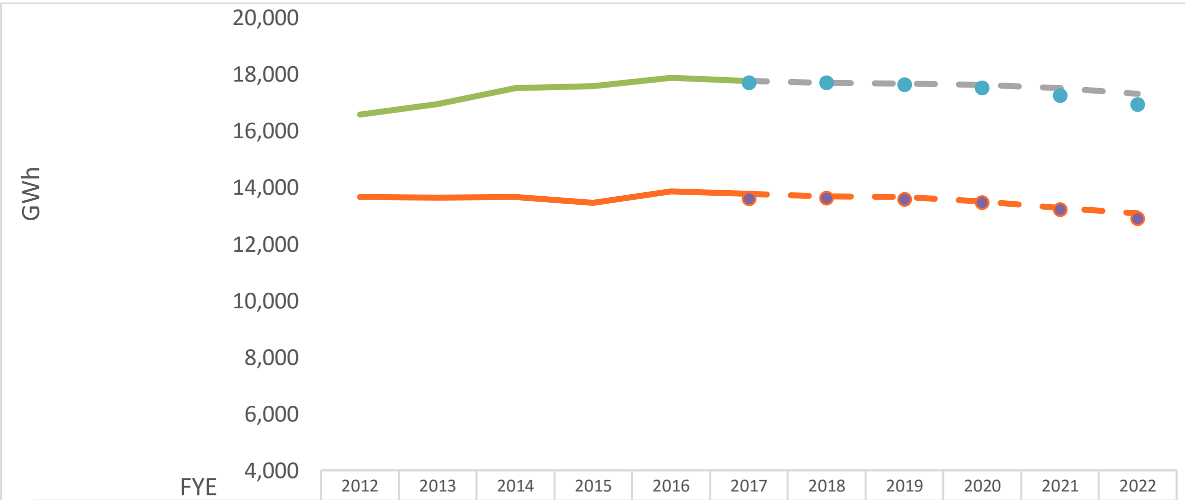
Contents

1 Executive summary

This report presents the Energy and Customer Numbers trend forecasts for the 2017-18 Annual Price Review as well as expenditure forecasts and network charges for regulatory submissions. The main points are as follows:

- The average actual annual customer numbers growth of the recent five-year period to June 2015 is approximately 21,160 per annum, representing a compound annual growth rate of 2.0%. This represents an additional 105,801 customers with total customers increasing from 991,244 in FYE 2012 to 1,097,045 in FYE 2017.
- The forecast for the five-year period (i.e. FYE 2017-2022, inclusive) is on average 19,169 connections per annum and a lower compound annual growth rate of 1.7% for FYE 2017-2022. The forecast includes the connection of approximately 95,845 residential and commercial customers over the period FYE 2017-2022 with a total connection forecast of 1.2M as FY 2022.
- Looking at sales volumes, Distribution Export Sales volumes (GWh) declined by 0.06% on average from FYE 2012 to FYE 2017 while total sales (GWh) grew by 1.2% on average over the same period.
- Distribution Export Energy sales are forecast to contract by 1.0% per year to FYE 2022. Transmission Loads will likely grow by 1.1% per year, leading to total contraction in energy sales of 0.5% per year.

Figure 1: Export Forecast comparison



FYE	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Distribution Sales (a)	13,651	13,639	13,665	13,456	13,860	13,769					
Distribution Sales (f)						13,769	13,691	13,656	13,505	13,276	13,083
Total Sales (a)	16,575	16,936	17,509	17,587	17,875	17,764					
Total Sales (f)						17,764	17,698	17,663	17,628	17,502	17,309
Total Sales (2016 f)						17,712	17,701	17,628	17,518	17,258	16,933
Distribution Sales (2016 f)						13,615	13,638	13,572	13,469	13,217	12,899

Table 1: Summary of forecast export energy volumes (GWh)

Tariff	2017	2018	2019	2020	2021	2022
RT1	4,434	4,234	4,142	4,035	3,946	3,863
RT13	974	1,012	1,051	1,051	1,028	1,003
RT3	64	60	56	53	50	48
RT15	55	53	53	52	52	51
RT2	1,089	1,051	990	930	872	816
RT14	28	59	90	123	155	189
RT4	1,058	965	886	829	782	738
RT16	72	102	132	161	190	217
RT5	650	672	722	758	803	835
RT6	1,942	2,029	2,046	2,037	1,964	1,948
RT7	2,595	2,645	2,679	2,672	2,637	2,591
RT7Z	449	444	441	437	431	421
RT8	191	196	192	186	181	176
RT9	131	134	137	141	143	146
RT10	38	37	39	40	41	43
Distribution Export Sales	**13,769**	**13,691**	**13,656**	**13,505**	**13,276**	**13,083**
TRT1	3,995	4,007	4,007	4,123	4,226	4,226
Total Export Sales	**17,764**	**17,698**	**17,663**	**17,628**	**17,502**	**17,309**

2 Introduction

Purpose

This document presents the 2017 forecasts required as input for the 2017-18 Annual Price Review. The Review requires forecasts of energy volumes measured in gigawatt-hours (GWh) and the number of customers by network tariff. Western Power primarily earns revenue on export volumes (energy consumed by the customer from the grid). A growing number of customers import (surplus energy transferred to the grid by the customer); requiring new bi-directional forecasting.

Definitions

Western Power assigns customers to a tariff according to various criteria as set out in the Price List Information. In order to measure the number of customers assigned to each tariff, it is necessary to have a clear, unambiguous definition of a customer. In this report, each National Meter Identifier (NMI) code represents a customer. For tariffs without NMIs (i.e. streetlights and unmetered supplies), network connection counts are used. Note that when referring to NMI counts and connection numbers, the term ‘connection numbers’ is used as a collective noun since every NMI also has a network connection.

In addition, a customer is restricted to those customers whose NMI status is active. This NMI status excludes extinct and inactive NMIs. Consequently, discrepancies arise when comparing the customer numbers reported here to customer numbers compiled according to alternative definitions. For example, some definitions also include inactive NMIs.

The energy volume assigned to a given tariff is simply the energy aggregated across all NMIs associated with the specific tariff.

Major change in tariff structure

Four new bidirectional tariffs introduced in FY 2015-16 are RT13; RT14; RT15; and RT16. These new tariffs apply to residential and commercial customers with small-scale[1] solar photovoltaic (PV) electricity generation systems.

The reallocation of energy volume and customer numbers to the new tariffs (based on retailer provided information on a monthly basis) impedes comparison of tariff based customer numbers and energy volumes in this report to previous forecast reports. An approximate reconstruction of the old tariff structures provides a basis to compare forecasts.

Note that this can only be approximate because:

- Some NMIs that were active last year are now either extinct or inactive
- Similarly, there are newly active NMIs that did not exist last year
- There has been a considerable amount of customer reallocation from commercial to residential tariffs.

[1] In this report, a small-scale solar photovoltaic electricity generation system is one that does not require a Declared Sent-Out Connection.

3 Forecast variables

This section describes the forecast variables, viz., energy volume and connection numbers by tariff. The next subsection provides the descriptive names and tariff codes for each tariff. The remaining subsections provide basic summary statistics and an overview of the explanatory variables used to forecast each tariff.

3.1 Dependent variable definitions

The dependent variables are (1) the number of customers and (2) the amount of electricity exported to customers by tariff. See Table 2 for a list of the tariffs and a brief description.

Table 2: Tariff definitions

Tariff	Descriptive name
RT1	Anytime Energy (Residential) Exit Service
RT2	Anytime Energy (Business) Exit Service
RT3	Time of Use Energy (Residential) Exit Service
RT4	Time of Use Energy (Business) Exit Service
RT5	High Voltage Metered Demand Exit Service
RT6	Low Voltage Metered Demand Exit Service
RT7/RT7Z[2]	High Voltage Contract Maximum Demand Exit Service
RT8	Low Voltage Contract Maximum Demand Exit Service
RT9	Streetlighting Exit Service
RT10	Un-Metered Supplies Exit Service
RT13	Anytime Energy (Residential) Bi-directional Service
RT14	Anytime Energy (Business) Bi-directional Service
RT15	Time of Use (Residential) Bi-directional Service
RT16	Time of Use (Business) Bi-directional Service
TRT1	Transmission Exit Service

Source: Western Power, *2015/16 Price List Information*, Table 1, p. 4; http://www.westernpower.com.au/documents/PriceListInformation20152016.pdf

As indicated, the tariffs group customers by their basic type (i.e. residential, business), by demand type (i.e. volumetric, demand/capacity) and direction (entry, exit, bi-directional). 107 monthly observations (eight years and eleven months) were available to establish forecast trends (Jan08 – Nov16).

3.2 External variables

This section provides a description of the external (i.e. independent) variables included in the forecast training data set[3]. Selection of these variables is justified by economic or demonstrated statistical relevance. Note that other variables could also have been included but are either not available or are difficult to obtain reliable forecasts.

The following categories apply to the selected external variables:

- Economic Activity: variables that measure the level of activity in the economy
- Price: volumetric component of the electricity price

[2] RT7 indicates a metered connection to the network at a distribution connection point. RT7Z indicates a metered connection directly to a zone substation.
[3] The training data set, also known as the estimating data set, is the data used to calculate forecast model parameters.

- Seasonal: temperature and other weather variables
- Substitution: capture influence of alternatives to network delivered electricity

Table 3: External variable description

Category	Variable	Description
Economic	CPI	Consumer Price Index (Annual, Monthly, Change)
Economic	WPN Popn A	WA Tomorrow Popn Forecasts (A band; WPN area)
Economic	WPN Popn B	WA Tomorrow Popn Forecasts (B band; WPN area)
Economic	WPN Popn C	WA Tomorrow Popn Forecasts (C band; WPN area)
Economic	WPN Popn D	WA Tomorrow Popn Forecasts (D band; WPN area)
Economic	WPN Popn E	WA Tomorrow Popn Forecasts (E band; WPN area)
Economic	Regional Final Demand	WPN Regional Demand Forecasts (Annl, Mthly, Change)
Economic	Gross Regional Product	WPN GRP Forecasts (Annl, Mthly, Change)
Price	Tariff A1	Synergy Retail Variable Residential Tariff
Price	Tariff L1	Synergy Retail Variable Business Tariff
Seasonal	Public Holiday	Count of Public Holidays per Month
Seasonal	School Holidays	Count of School Holiday days per month
Seasonal	Days in Month	Count of Days per month
Seasonal	Average Temp	Avg Temperature observed at nearest reputable BOM station
Seasonal	CDD	Cooling Degree Days calculated
Seasonal	HDD	Heating Degree Days calculated
Seasonal	Max Temp	Max temperature observed at nearest reputable BOM station
Seasonal	Min Temp	Min temperature observed at nearest reputable BOM station
Substitution	PV Count	Count of Bidirectional customers
Substitution	PV Capacity	Sum of PV Inverter capacity

As indicated above, there are many variables included in the estimating data set. Many of these variables are highly correlated, so most of Western Power's forecast models only include a small subset of these variables based on a balance of goodness of fit and forecasting accuracy criteria.

The variables and associated data are from published documents by Western Australian Government agencies, Bureau of Meteorology (BOM), Australian Bureau of Statistics (ABS), Clean Energy Regulator (CER), Housing Industry Association (HIA), and BIS Shrapnel.

Gross Regional Product is a broad measure of economic activity that typically accounts for a small component of monthly variation in electricity demand. Nevertheless, it will have an influence on the long-run trend in electricity demand since electricity is one of the inputs for productive activity.

Note that other economic measures of overseas demand for Western Australia's exports (such as exchange rates, the terms of trade, commodity prices etc.) are also likely to be influential on electricity demand. However, the relatively short time series of electricity demand impedes precise estimation of the impact on electricity demand. Moreover, the high volatility of these series and the absence of credible long-term forecasts for these additional economic variables limit the suitability of their use.[4]

Electricity prices have an inverse relationship with electricity demand, or at least network delivered electricity demand. Assuming fixed customers' budgets in the short-term, a higher

[4] Note that these variables could be forecast using the International Monetary Fund's global VAR models.

price (i.e. higher electricity tariffs) should have a persistent dampening effect on electricity demand. This is an important factor for long-term forecasting.

An issue limiting the usefulness of the tariff is limited variation in prices. Typically, consumer electricity prices update just once a year. With just nine years of time series data, it is difficult to estimate a statistically precise relationship between electricity prices and the demand for network delivered electricity.

The number of solar PV electricity generation systems is a marginal substitute for network delivered electricity. Ideally, a price series for solar PV use would be better than the quantity for measuring cross-price elasticity, but such as series is not available. In the absence of the price series, we use the quantity series as a control for the substitution effect.

In considering alternatives to network delivered electricity, a notably absent variable is the price of natural gas. Given the extensive reach of the gas distribution network, it is likely that electricity and gas services compete, particularly in heating and cooking services. However, gas prices have typically increased at a faster rate than retail electricity prices, suggesting a long-term consumer preference for electricity. In turn, this suggests a high market share for electricity in supplying energy services.

Nevertheless, the prospect of gas prices to consumers beginning a long-term decline suggests that the prospect of competition from gas is more likely in the future.

Finally, cooling and heating degree-days control for the annual seasonal cycle. Temperature extremes tend to increase electricity demand, primarily to satisfy refrigeration and space heating demand.

Forecasting solar PV installations

The absence of reliable long-term forecasts for the number of solar PV installations is a serious impediment to developing accurate forecasts for electricity demand. Although the mass introduction of solar PV installations is a relatively recent phenomenon, the rate of adoption has had a material demand-reducing impact.

Given its importance, Western Power has conducted several investigations into forecast methods. The primary focus has been the investigation of sigmoid functions (otherwise known as diffusion curves) to forecast the expected duration of the exponential growth phase as well as the longer-term market saturation level.

The investigation has revealed that aside from large changes to government subsidy for solar PV systems, the rate of adoption has been approximately constant. This suggests an approximately linear relationship with the growth in the housing and commercial building stock. In addition, the rate of growth in solar PV installations is not sufficient to demonstrate the short-term superiority of a non-linear forecast.

At this point, the key observations are:

- There is a higher proportion of new solar PV systems on new buildings.
- Installations on commercial buildings are likely to be larger than on residential buildings. Hence, faster demand reduction will occur across commercial tariffs.

Forecasting cooling and heating degree days

Long term temperature forecasts have been developed by sampling the historic temperature per weather station. Where medium term forecasts exist for weather, the relevant percentile was forecast; else, forecast weather is expected to take the median. In addition, there may be a changing relationship between temperature variation and associated electricity demand, such as:

- Continuing increases in penetration of temperature-dependent loads like air-conditioners (larger systems, or more split systems per household), will continue to increase the electricity demand impacts of extreme temperatures.
- Changes in demographics and technology adoption; for example, with a higher proportion of retirees with air-conditioners and solar PV systems, own-use of solar PV generated electricity may be increasing. This would appear as a daytime reduction in temperature related network demand.
- Changes in appliance and building efficiency; this is likely to be a subtle but persistent effect over time. Various estimates produced for the Australian Electricity Market Operator suggest this influence could amount to 0.5% per year. This efficiency effect remains unidentified in Western Power's demand models due to the difficulty in statistically separating the efficiency effect from other trends evident in the data.

Prospect of further substitution via new technology

Since the 2015 forecasting round, speculation about mass adoption of other network competing technologies has intensified. Widespread adoption of battery storage systems could have a negative impact on network delivered electricity demand.

Western Power is monitoring developments in battery related marketing such as the Tesla PowerWall® system. This is the first time that battery systems are being included in the forecast.

Factors affecting mass adoption of battery systems are:

- The present value cost of a battery system against the present value of the cost of purchasing network delivered electricity. If the present value of battery systems offers a lower cost (i.e. a net saving), wider adoption will occur.
- Consumer preference bias; if consumers perceive a positive utility in owning a battery storage system, then there need not be a net saving before mass adoption occurs. Measuring the desirability of battery systems is within the domain of marketing experts. Consequently, Western Power has been exploring the possibility of using marketing based models, such as EYC3's Simulait model

Customer incentive modelling has been completed to compare the net present costs of:

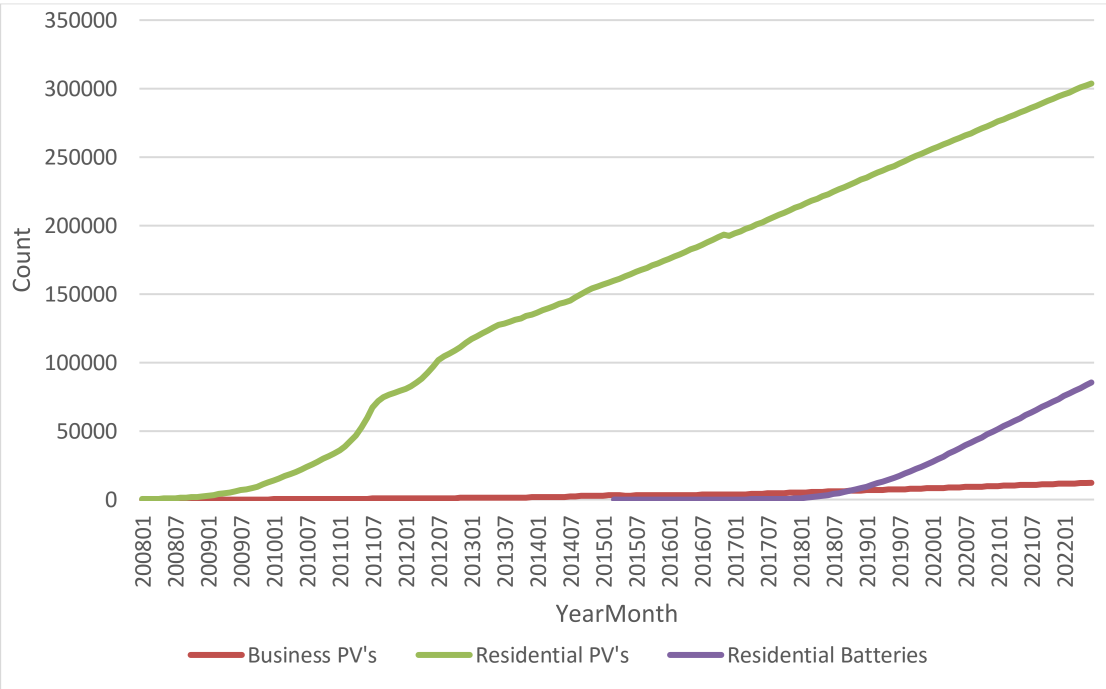
- Grid Supply (drawing all load requirements from the grid)
- Partial Load Defection (installing batteries and PV's to self-supply 60-70% of required load)
- Full Load Defection (installing batteries and PV's to self-supply >95% of required load)
- Grid Defection (installing sufficient technology to allow full disconnection)

With the following results:

Scenario *	2017 Net Present Cost	2027 Net Present Cost	2037 Net Present Cost
Grid Supply (A1)	$8,256.05	$10,805.24	$14,231.14
Partial Load defect	$15,359.90	$10,837.77	$10,003.55
Full Load defect	$36,047.24	$22,757.15	$21,039.51
Grid defect	$51,294.80	$33,624.31	$31,156.38

As most customers will have the incentive to partially load defect in the next 5-10 years, substantial battery uptake has been assumed as shown in the technology forecasts shown below.

Graph 4: Technology Forecasts



4 Forecasts

This section presents the 2017 forecasts of connection numbers by tariff.

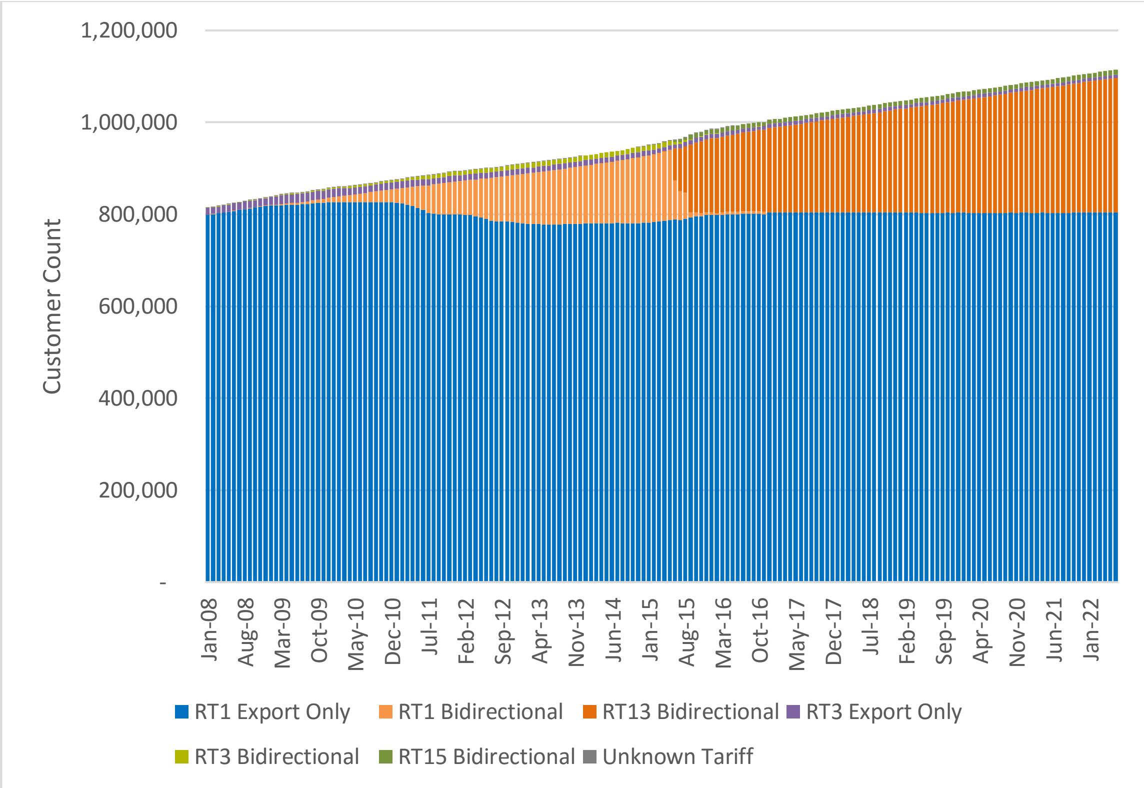
Table 5: average connection numbers per financial year (totals exclude unmetered connections)

Actuals Tariff	FYE 2012	2013	2014	2015	2016	2017
RT1	871,182	886,883	905,381	922,431	811,759	805,153
RT13	-	-	18	6,183	152,175	183,723
RT2	82,961	83,316	83,874	85,316	76,208	74,250
RT14	2	2	10	113	1,043	1,363
RT3	21,536	21,841	21,751	20,337	10,878	8,295
RT15	-	-	-	767	8,922	9,415
RT4	13,459	14,390	14,771	14,453	11,502	9,966
RT16	1	1	4	104	251	385
RT5	115	121	125	135	166	290
RT6	1,640	1,753	2,100	2,786	3,489	3,830
RT7	246	255	261	264	266	271
RT7Z	8	8	8	9	10	9
RT8	56	56	56	58	58	57
RT9		*237,387*	*240,864*	*249,640*	*255,731*	*265,442*
RT10		*15,862*	*15,675*	*15,420*	*15,801*	*16,318*
TRT1	38	38	38	38	38	38
Total	991,244	1,008,664	1,028,397	1,052,994	1,076,765	1,097,045

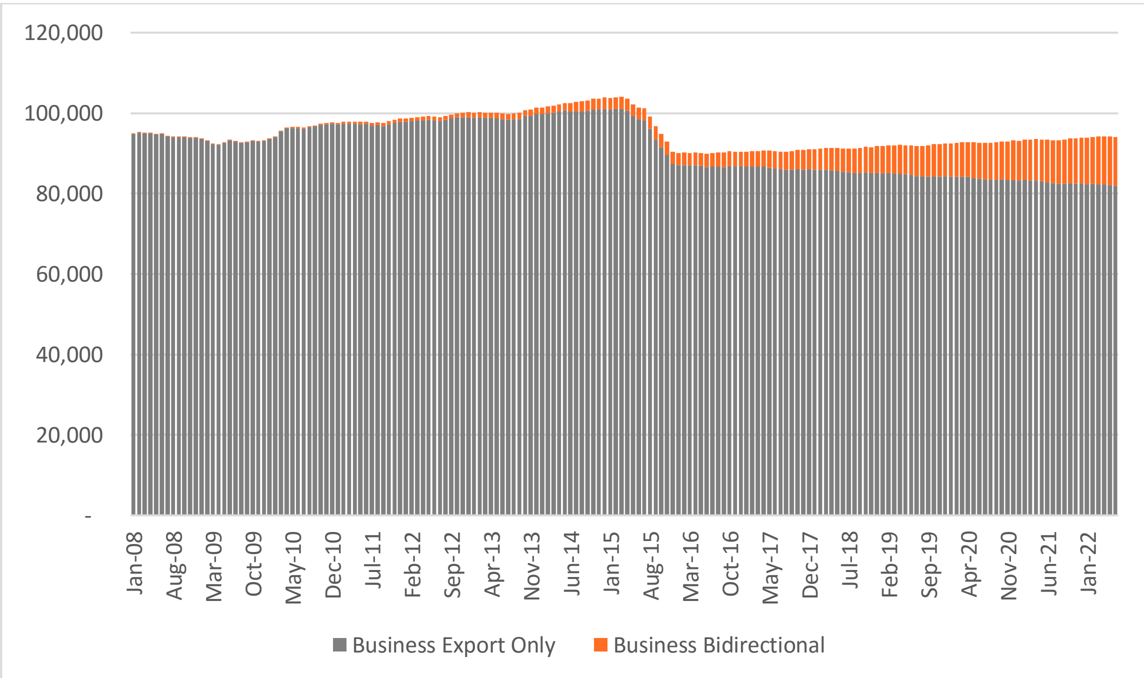
Table 6: Forecast average connection numbers per FY (totals exclude unmetered connections)

Forecast Tariff	FYE 2017	2018	2019	2020	2021	2022
RT1	805,153	803,987	803,649	803,312	803,333	803,676
RT13	183,723	204,050	224,365	244,678	264,633	284,267
RT2	74,250	73,608	72,977	72,319	71,635	70,927
RT14	1,363	1,363	1,363	1,363	1,363	1,363
RT3	8,295	7,993	7,722	7,465	7,223	6,996
RT15	9,415	9,631	9,902	10,159	10,401	10,628
RT4	9,966	9,760	9,591	9,421	9,251	9,081
RT16	385	548	717	887	1,057	1,227
RT5	290	288	292	296	300	303
RT6	3,830	3,901	3,935	3,967	3,998	4,029
RT7	271	276	279	282	284	285
RT7Z	9	9	9	9	9	10
RT8	57	57	58	58	58	58
RT9	*265,442*	*272,664*	*280,437*	*288,415*	*296,223*	*304,058*
RT10	*16,318*	*16,198*	*16,345*	*16,493*	*16,641*	*16,789*
TRT1	38	38	38	39	40	40
Total	1,097,045	1,115,509	1,134,897	1,154,255	1,173,585	1,192,890

Graph 7: Residential Customers by Tariff



Graph 8: Business Customers



This section presents the 2017 forecasts of export consumption by tariff.

Table 9: export consumption per financial year (GWh)

Actuals	FYE					
Tariff	2012	2013	2014	2015	2016	2017
RT1	4,985	4,967	4,961	4,740	4,392	4,434
RT13	-	-	-	34	778	974
RT2	1,307	1,221	1,176	1,088	1,100	1,089
RT14	-	-	-	2	14	28
RT3	170	164	158	138	83	64
RT15	-	-	-	2	50	55
RT4	2,100	2,145	2,037	1,812	1,411	1,058
RT16	-	-	2	29	55	72
RT5	370	371	393	409	498	650
RT6	1,402	1,440	1,572	1,776	1,994	1,942
RT7	2,690	2,644	2,569	2,590	2,642	2,595
RT7Z	402	408	426	470	474	449
RT8	225	226	218	210	207	191
RT9	*122*	*126*	121	124	129	131
RT10	*35*	*34*	33	32	33	38
TRT1	2,925	3,297	3,843	4,131	4,014	3,995
Total	16,732	17,045	17,509	17,587	17,875	17,764

Table 10: Forecast export consumption per FY (GWh)

Forecast	FYE					
Tariff	2017	2018	2019	2020	2021	2022
RT1	4,434	4,234	4,142	4,035	3,946	3,863
RT13	974	1,012	1,051	1,051	1,028	1,003
RT2	1,089	1,051	990	930	872	816
RT14	28	59	90	123	155	189
RT3	64	60	56	53	50	48
RT15	55	53	53	52	52	51
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RT16	72	102	132	161	190	217
RT5	650	672	722	758	803	835
RT6	1,942	2,029	2,046	2,037	1,964	1,948
RT7	2,595	2,645	2,679	2,672	2,637	2,591
RT7Z	449	444	441	437	431	421
RT8	191	196	192	186	181	176
RT9	131	134	137	141	143	146
RT10	38	37	39	40	41	43
TRT1	3,995	4,007	4,007	4,123	4,226	4,226
Total	17,764	17,698	17,663	17,628	17,502	17,309

This section presents the 2017 forecasts of network imports by tariff.

Table 11: distribution network imports from bidirectional customers per financial year (GWh)

Actuals Tariff	FYE 2012	2013	2014	2015	2016	2017
RT1	111.9	173.9	222.6	282.8	28.0	6.2
RT13	-	-	-	8.6	328.3	464.6
RT2	0.8	2.5	2.1	6.1	6.2	9.0
RT14	-	-	-	0.2	3.3	6.8
RT3	13.1	16.7	18.0	18.6	1.8	0.4
RT15	-	-	-	0.4	16.8	19.0
RT4	1.0	6.0	0.9	2.3	3.3	3.3
RT16	-	-	-	0.3	1.3	2.5
RT5	0.0	0.0	0.0	0.0	0.0	0.5
RT6	0.0	0.0	0.0	0.1	0.3	0.8
RT7	0.3	0.9	3.5	3.1	2.4	3.0
RT7Z	0.0	0.0	0.0	0.0	0.0	0.0
RT8	0.0	0.0	0.0	0.0	0.0	0.0
RT9	-	-	-	-	-	-
RT10	-	-	-	-	-	-
Total	127.1	200.0	247.1	322.5	391.7	516.1

Table 12: Forecast distribution network imports from bidirectional customers per FY (GWh)

Forecast Tariff	FYE 2017	2018	2019	2020	2021	2022
RT1	6.2	-	-	-	-	-
RT13	464.6	599.3	721.7	811.1	874.2	928.2
RT2	9.0	-	-	-	-	-
RT14	6.8	23.8	32.8	43.1	57.5	73.6
RT3	0.4	-	-	-	-	-
RT15	19.0	20.4	21.6	22.7	24.1	25.4
RT4	3.3	-	-	-	-	-
RT16	2.5	7.1	8.5	10.3	12.2	14.3
RT5	0.5	0.6	0.6	0.6	0.6	0.7
RT6	0.8	0.8	0.8	0.8	0.8	0.8
RT7	3.0	3.0	3.4	3.9	4.4	5.0
RT7Z	0.0	0.0	0.0	0.0	0.0	0.0
RT8	0.0	0.0	0.0	0.0	0.0	0.0
RT9	-	-	-	-	-	-
RT10	-	-	-	-	-	-
Total	516.1	655.0	789.4	892.5	973.8	1,048.0