Jemena Electricity Networks (Vic) Ltd

2016-20 Electricity Distribution Price Review Regulatory Proposal

Attachment 3-3

Electricity consumption forecasts

Public

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ACIL ALLEN CONSULTING

A REPORT TO
JEMENA ELECTRICITY NETWORKS

16 DECEMBER 2014

ELECTRICITY CONSUMPTION FORECASTS

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Executive summary

Jemena Energy Networks (JEN) is an electricity Distribution Network Service Provider (DNSP). It distributes electricity to over 300,000 customers throughout the north-west of Melbourne. JEN's network comprises six terminal stations and 26 zone substations.

As with all electricity DNSPs in the National Electricity Market (NEM), JEN is subject to economic regulation administered by the Australian Energy Regulator (AER) under the National Electricity Rules (NER). JEN's current regulatory period will end on 31 December 2015 and it must submit a regulatory proposal for the next five-year period by 30 April 2015. Among many other things, that proposal must include forecasts of energy consumption and customer numbers.

JEN engaged ACIL Allen Consulting (ACIL Allen) to assist it in preparing its submission to the AER in relation to consumption, and demand forecasting. This report relates to consumption and customer numbers. A subsequent report will relate to demand.

The results presented in this report were prepared using econometric techniques. Specifically, regression models were estimated to quantify the relationship between consumption and/ or customer numbers and their drivers. Those models were used with projections of the drivers to produce baseline forecasts.

Two post model adjustments were made to the residential forecasts to account for the impact of ongoing take-up of solar PV systems and the impact of flexible pricing. Those impacts were calculated in separate models described in this report.

This process was applied at the tariff class level for the following tariff classes:

- residential
- small business
- large business low voltage (large LV)
- large business high voltage (large HV)
- large business sub transmission (large ST).

The tariff class forecasts were disaggregated to the tariff level. The tariff level results are provided in the body of the report.

Consumption forecasts - residential

The forecasts of residential consumption are shown in Table ES 1 and Figure ES 1.

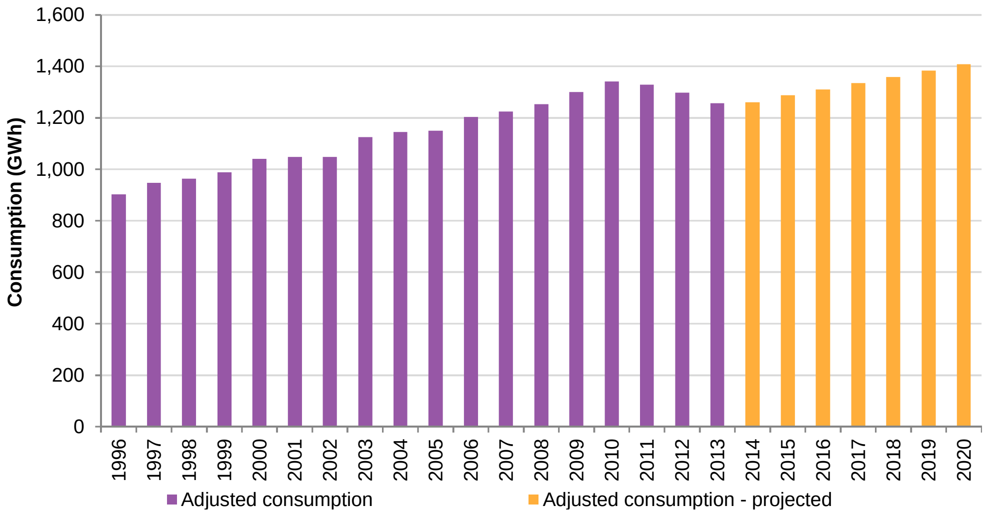
Table ES 1 **Residential consumption forecasts, 2016 to 2020**

Forecast	2016	2017	2018	2019	2020
	GWh	GWh	GWh	GWh	GWh
Baseline	1,319	1,345	1,373	1,401	1,430
Flexible pricing	0	0	0	0	0
Solar PV	-8	-11	-14	-18	-21
Forecast consumption	**1,311**	**1,334**	**1,358**	**1,384**	**1,408**

Source: ACIL Allen Consulting

Residential consumption is forecast to increase by 97 GWh over the period between 2016 and 2020. This corresponds to a growth of 7.4 per cent, and represents a recovery from the decline observed between 2010 and 2013. The 2010 peak in consumption of 1,340 GWh is expected to be exceeded until 2018. However, the average growth rate over the period is not expected to be as high as that observed between 2006 and 2010.

Figure ES 1 **Residential consumption, 1996 to 2020**



Source: ACIL Allen Consulting

Consumption forecasts – non-residential

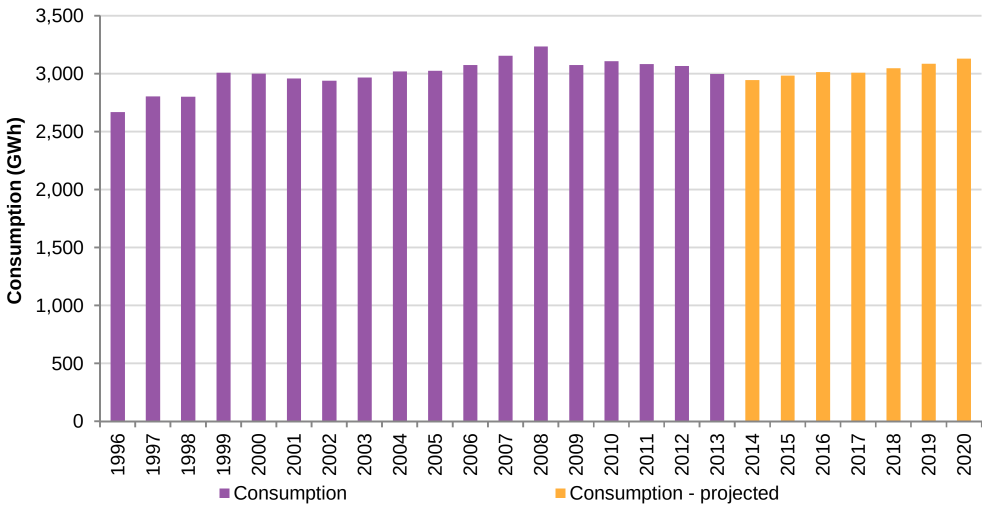
Forecasts for non-residential consumption are provided in Table ES 2 and Figure ES 2.

Table ES 2 **Non-residential consumption forecasts, 2016 to 2020**

Tariff	2016	2017	2018	2019	2020
	GWh	GWh	GWh	GWh	GWh
Total small business	734	749	766	784	803
Total large LV	1,312	1,333	1,354	1,376	1,398
Total large HV	661	620	620	620	620
Large -ST	308	308	308	308	308
Total non-residential consumption	**3,014**	**3,009**	**3,048**	**3,087**	**3,129**

Source: ACIL Allen Consulting

Figure ES 2 **Non residential consumption, 1996 to 2020**



Source: ACIL Allen Consulting

Total non-residential consumption is forecast to grow by 115 GWh, or 3.8 per cent, between 2016 and 2020. The largest component of consumption is large LV. However, the most significant growth in consumption comes from small business, which is forecast to increase by 9.4 per cent over the period.

Customer numbers forecasts - residential

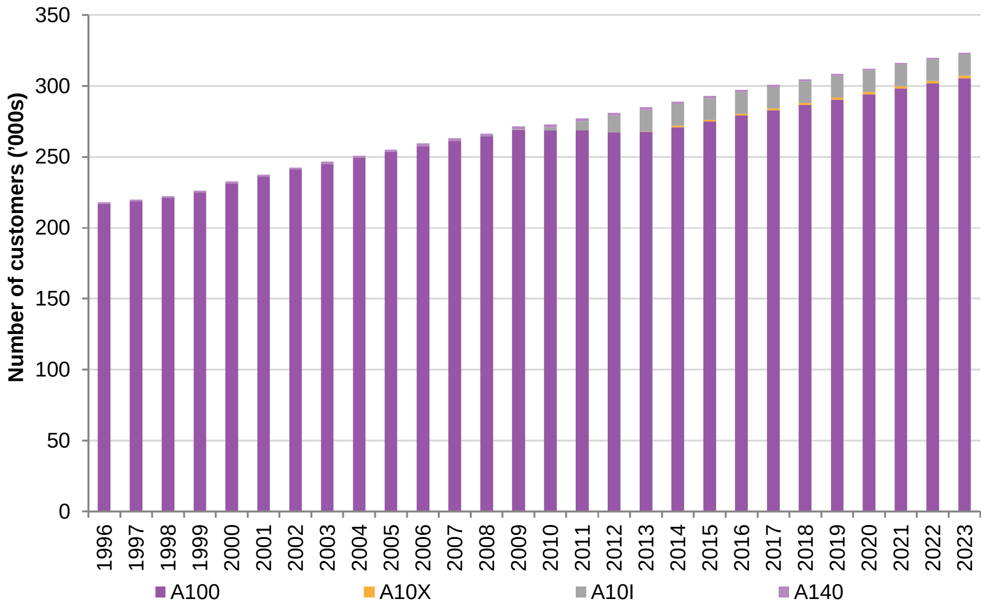
The forecasts of residential customer numbers are shown in Table ES 3 and Figure ES 3. There is a significant decrease in customers on the general purpose tariff (A100) and a small increase in the number of customers with flexible pricing. This reflects the assumed rate of migration to flexible pricing. Otherwise, the increases in customer numbers are driven primarily by expected increases in the population within JEN's distribution region. The same is true at the individual tariff level except for the take-up of flexible pricing and in cases where tariffs are closed to new customers.

Table ES 3 **Forecast residential customer numbers by tariff, 2016 to 2020**

	2016	2017	2018	2019	2020
A100	279,096	282,762	286,489	290,277	294,129
A10X	1,200	1,300	1,400	1,500	1,600
A10I	15,285	15,280	15,276	15,272	15,269
A140	1,553	1,474	1,392	1,308	1,222
Total residential customers	**297,134**	**300,815**	**304,556**	**308,357**	**312,220**

Source: ACIL Allen Consulting

Figure ES 3 **Forecast residential customer numbers by tariff, 2016 to 2020**



Source: ACIL Allen Consulting

Customer numbers forecasts – non-residential

The forecast number of customers on non-residential tariffs is shown in Table ES 4.

Large LV customer numbers are forecast to grow the fastest over the forecast period, at a compound annual growth rate of 3.2 per cent per year. The number of large HV customers is forecast to decline by one customer over this period (due to the closure of the Ford manufacturing facility).

Table ES 4 **Forecast non-residential customer numbers by tariff, 2016 to 2020**

Tariff	2016	2017	2018	2019	2020
Total small business	26,881	27,167	27,455	27,747	28,041
Total large LV	1,423	1,469	1,516	1,565	1,616
Total large HV	78	77	77	77	77
Large ST	3	3	3	3	3
Total non-residential customers	**28,385**	**28,715**	**29,051**	**29,392**	**29,737**

Source: ACIL Allen Consulting

Billed demand forecasts

The forecasts of billed contract demand are shown in Table ES 5.

This table includes the effect of several changes JEN intends to make:

- in 2016 JEN will conduct a demand reset – revising the contract demand for customers already on demand tariffs to reflect their recent demand
- from 2017 JEN intends to transition all customers to demand tariffs. Therefore
  - in small business tariff class the number of customers on the demand tariff increases by 26,482 customers, with the result that total billed demand increases substantially

  - in the residential tariff class the number of customers on demand tariffs increases from zero in 2016 to more than 300,000 in 2017 and billed demand increases accordingly
- in 2017 JEN intends to change the demand tariffs applicable to large customers from demand tariffs based on demand measured in MW to demand measured in MVA.

Table ES 5 **Forecast billed demand - 2016 to 2020**

Tariff	2016	2017	2018	2019	2020
	MW	MW	MW	MW	MW
Total residential	N/A	896.1	912.3	929.6	946.3
Total small business	51.4	1,214.8	1,232.1	1,250.2	1,270.4
	MW	MVA	MVA	MVA	MVA
Total large LV	467.0	542.1	551.9	561.8	571.9
Total large HV	207.5	213.9	214.1	214.3	214.5
Total large ST	69.6	85.0	85.0	85.0	85.0

Source: ACIL Allen Consulting

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1 Introduction

Jemena Electricity Networks (JEN) is an electricity Distribution Network Service Provider (DNSP). It distributes electricity to over 300,000 customers throughout the north-west of Melbourne. JEN's network comprises six terminal stations and 26 zone substations as shown in Figure 1.

As with all electricity DNSPs in the National Electricity Market (NEM), JEN is subject to economic regulation administered by the Australian Energy Regulator (AER) under the National Electricity Rules (NER). JEN's current regulatory period will end on 31 December 2015 and it must submit a regulatory proposal for the next five-year period by 30 April 2015. Among many other things, that proposal must include forecasts of energy consumption.

JEN engaged ACIL Allen Consulting (ACIL Allen) to assist it in preparing its submission to the AER in relation to consumption and demand forecasting. Therefore, ACIL Allen's reports for JEN address two separate, but related, concepts - namely demand and consumption. There is room for confusion between these two concepts because, in economic terms, both can be thought of as demand. However, they are distinct, and one should not be mistaken for the other.

To prevent confusion, these terms are defined as follows:

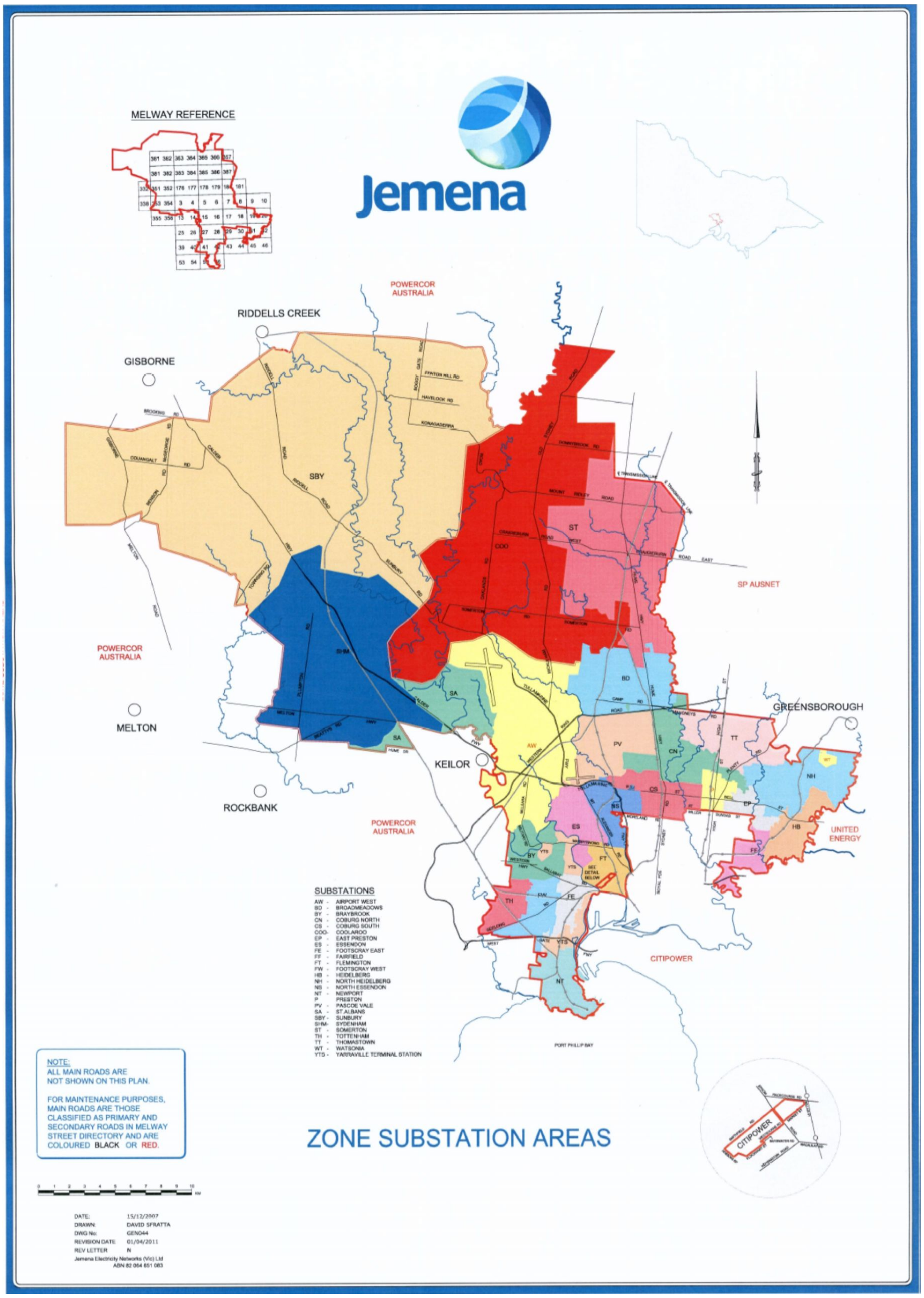
Demand: refers to the quantity of electricity that passes through a given element of a network at any given time. Theoretically, demand occurs, and can change, almost instantaneously. In practice, demand is usually reported once for each half hour interval and is the average of instantaneous recordings over the half hour period. Demand is measured in a multiple of watts (at the network level usually megawatts, or MW).

Consumption: refers to the quantity of energy used over a period of time. Consumption is commonly reported on a monthly, quarterly and annual basis, though any time period is possible subject to measurement constraints. Consumption is measured in a multiple of watt hours[1] (at the network level, usually gigawatt hours, or GWh). Mathematically, consumption is equal to average demand over time.

This report addresses forecasts of consumption. Projections of demand are presented in a separate report.

[1] Joules can also be used.

Figure 1 **JEN distribution region**



Data source: JEN Distribution system planning report 2011

1.1 Overview of consumption forecast methodology

The consumption forecasts presented in this report were prepared using a set of regression models that project consumption at the tariff class level for the following five tariff classes:

1. residential
2. small business
3. large business low voltage (large LV)
4. large business high voltage (large HV)
5. large business sub-transmission (large ST)

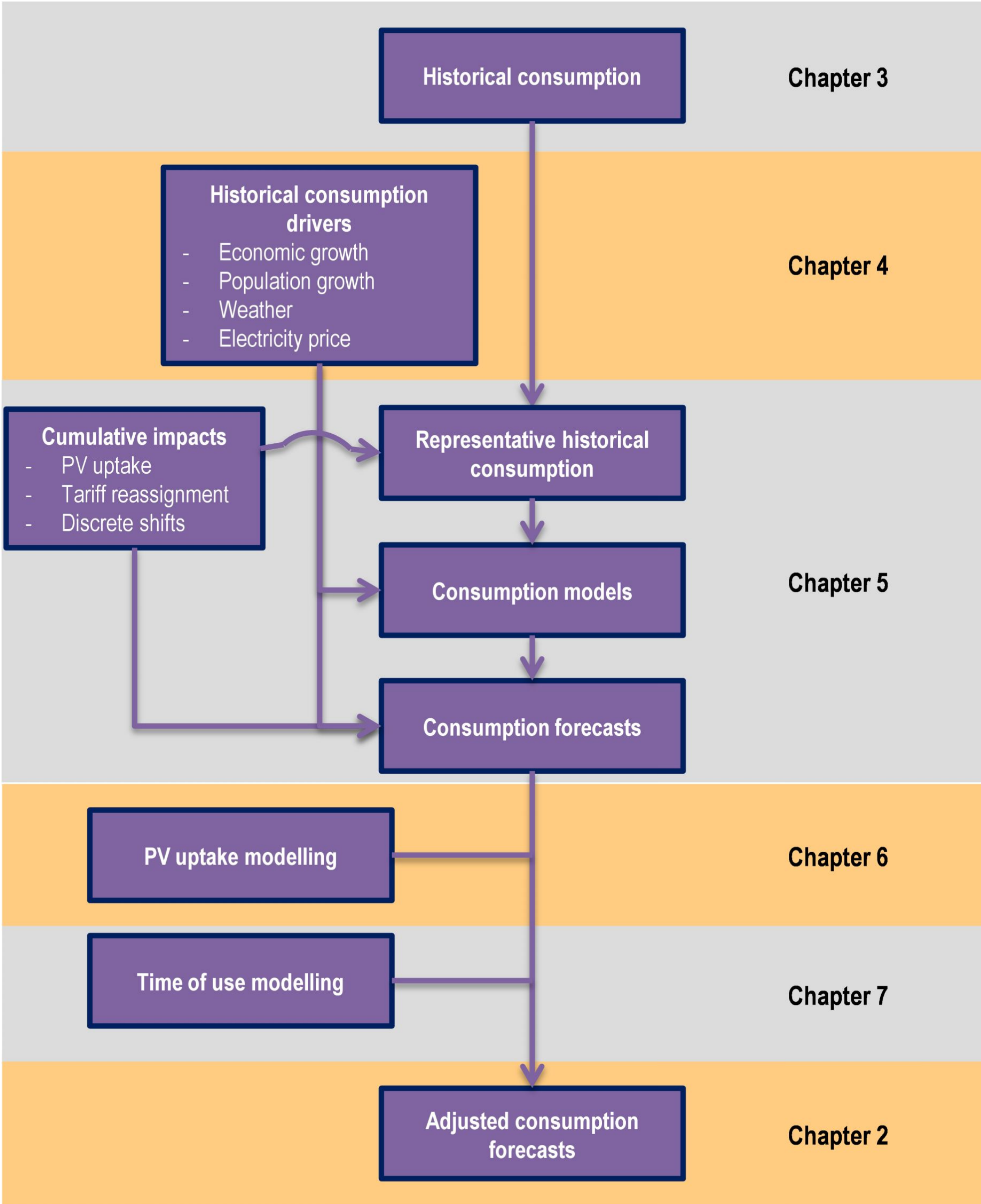
The modelling process is illustrated in Figure 2. Broadly, the process was to:

1. obtain historical data pertaining to consumption and customer numbers
2. make adjustments to the historical consumption data to approximate 'latent' consumption by 'adding back' the impact of:
   a) tariff reassignments
   b) electricity generated by solar photovoltaic (PV) systems and used 'on site by the customer
   c) large discrete shifts in consumption
3. estimate regression models to relate consumption to its drivers, on a consumption per customer basis for residential and some non-residential customers, and at an aggregate level for other customer types
4. use projections of the drivers to produce 'baseline' consumption forecasts
5. make adjustments to the baseline forecasts to:
   a) reverse the adjustments discussed as per step 2, above
   b) account for future discrete changes in consumption where these are anticipated
   c) account for the impact of additional solar PV systems projected to be installed in future (modelled separately)
   d) account for the future uptake of flexible pricing (modelled separately).

The adjustments mentioned are not applicable to all tariff classes. In particular, the impact of solar PV and time of use pricing are limited to residential tariffs and the impact of large discrete shifts is limited to the large business tariffs.

JEN has 28 distribution tariffs for which forecasts were produced by disaggregating from the tariff class level. Table 1 lists each of JEN's tariffs showing the corresponding tariff class and providing a brief description of each tariff.

Figure 2 **Conceptual diagram of consumption modelling**



Source: ACIL Allen Consulting

Table 1 **JEN Distribution tariffs**

Tariff name	Tariff class	Description
A100	Residential	General purpose (flat tariff)
A10X	Residential	Flexible pricing tariff
A10I	Residential	Time of use interval meter (closed)
A140	Residential	Time of use
A180	Residential	Off-peak heating (dedicated circuit)
A200	Small business	General purpose (flat tariff)
A210	Small business	Time of use weekdays
A230	Small business	Time of use weekdays – demand
A250	Small business	Time of use extended (closed)
A270	Small business	Time of use extended – demand (closed)
A290	Small business	Unmetered supply
A300	Large business – LV	Low voltage – 0.4-0.8 GWh/year, non embedded
A30E	Large business – LV	Low voltage – <0.8 GWh/year, embedded
A320	Large business – LV	Low voltage – 0.8-2.2 GWh/year, non-embedded
A32E	Large business – LV	Low voltage – 0.8-2.2 GWh/year, embedded
A340	Large business – LV	Low voltage – 2.2-6.0 GWh/year, non-embedded
A34E	Large business – LV	Low voltage – >2.2 GWh/year, embedded
A34M	Large business – LV	Low voltage – 2.2-6.0 GWh/year from multiple NMIs, non-embedded
A370	Large business – LV	Low voltage - >6.0 GWh/year, non-embedded
A37M	Large business – LV	Low voltage – >6.0 GWh/year from multiple NMIs, non-embedded
A400	Large business – HV	High voltage - <55 GWh/year, non-embedded
A40E	Large business – HV	High voltage – embedded customers
A40R	Large business – HV	High voltage (closed)
A480	Large business – HV	High voltage - >55 GWh/year, non-embedded
A500	Large business –ST	Subtransmission
A50A	Large business –ST	Subtransmission MA
A50E	Large business –ST	Subtransmission EG (embedded generators)

Source: JEN

1.2 Structure of this report

This report is structured as follows.

The forecasts themselves are presented first, in chapter 2.

The subsequent chapters address the inputs, methodology and post model adjustments in that order. Specifically:

- Chapter 3 provides an overview of the history of the variables to be forecast, namely consumption and customer numbers. The residential consumption model is based on average consumption per customer, so this is also shown.
- Chapter 4 provides an overview of the history of the drivers of consumption.
- Chapter 5 describes the methodology by which the forecasts were produced and the regression models that were used to produce the baseline.
- Chapters 6 and 7 deal with the two post model adjustments that were estimated separately. These were adjustments for
  - the impact of future uptake of solar PV systems, discussed in chapter 6
  - the impact of flexible pricing, discussed in chapter 7.

2 Consumption forecasts

This chapter summarises the consumption forecasts. These are discussed for residential customers and non-residential customers separately, with the latter including all tariff categories other than residential.

The methodology by which these forecasts were prepared and the inputs upon which they are based is described in the remainder of this report.

2.1 Residential forecasts

This section presents the forecasts of residential consumption and customers. As discussed in chapter 5 the consumption forecasts were produced by forecasting customer numbers and average consumption per customer separately. Therefore:

— section 2.1.1 provides total residential consumption forecasts and tariff breakdowns
— section 2.1.2 provides residential customer numbers forecasts and tariff breakdowns
— section 2.1.3 provides forecasts of consumption per average residential customer. These were prepared at the tariff class level (i.e. residential) so they are not broken down to tariff.

2.1.1 Residential consumption

The forecasts of residential consumption are shown in Table 2 and Figure 3.

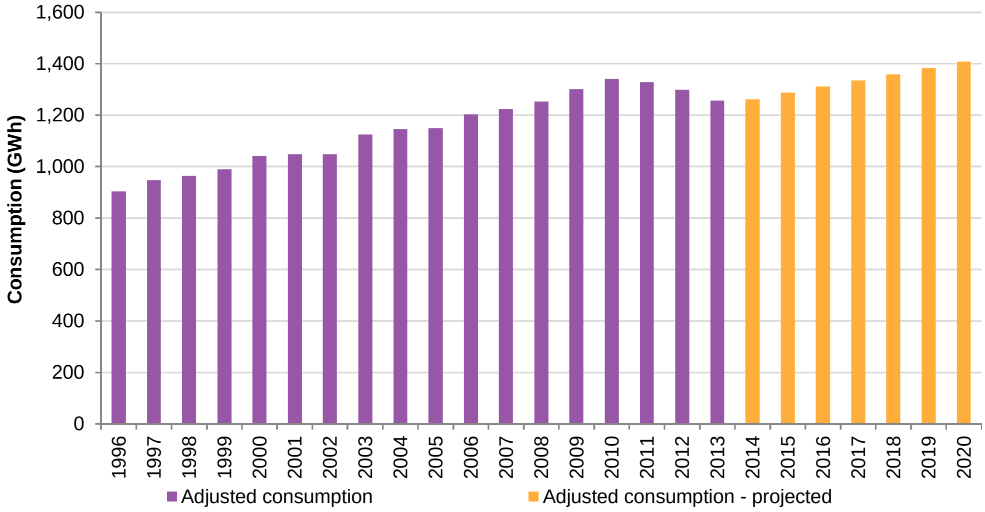
Table 2 **Residential consumption forecasts, 2016 to 2020**

Forecast	2016	2017	2018	2019	2020
	GWh	GWh	GWh	GWh	GWh
Baseline	1,319	1,345	1,373	1,401	1,430
Flexible pricing	0	0	0	0	0
Solar PV	-8	-11	-14	-18	-21
Forecast consumption	**1,311**	**1,334**	**1,358**	**1,384**	**1,408**

Source: ACIL Allen Consulting

Residential consumption is forecast to increase by 97 GWh over the period between 2016 and 2020. This corresponds to a growth of 7.4 per cent, and represents a recovery from the decline observed between 2010 and 2013. The 2010 peak in consumption of 1,340 GWh is expected to be exceeded until 2018. However, the average growth rate over the period is not expected to be as high as that observed between 2006 and 2010.

Figure 3 **Residential consumption - actual 1996 to 2013, and forecast 2014 to 2020**



Note: Figures up to 2013 are actual consumption. From 2014 onwards figures pertain to forecast consumption.
Source: ACIL Allen Consulting

Table 3 shows the residential consumption forecasts broken down to the tariff level. As the table shows, the post model adjustments are confined to particular tariffs. This reflects that fact that customers who take up flexible pricing offers will need to 'migrate' from one tariff to another to do so. It also reflects the tariffs that customers with new solar PV systems will need to use, given that tariff A10I is closed to new entrants.

Table 3 **Residential consumption forecasts by tariff**

	2016	2017	2018	2019	2020
	GWh	GWh	GWh	GWh	GWh
		Tariff: A100			
Baseline	1,163	1,180	1,198	1,218	1,236
Flexible pricing	-5	-5	-6	-6	-7
Solar PV	-8	-11	-14	-18	-21
Forecast consumption	**1,176**	**1,197**	**1,218**	**1,242**	**1,264**
		Tariff: A10X			
Baseline	8	8	9	10	11
Flexible pricing	5	5	6	6	7
Solar PV	0	0	0	0	0
Forecast consumption	**3**	**3**	**3**	**4**	**4**
		Tariff: A10I			
Forecast consumption	**70**	**71**	**72**	**73**	**75**
		Tariff: A140			
Forecast consumption	**13**	**13**	**12**	**11**	**11**
		Tariff: A180			
Forecast consumption	**50**	**51**	**52**	**53**	**54**
Total	**1,311**	**1,334**	**1,358**	**1,384**	**1,408**

Note: There are no TOU and solar PV impacts on Tariffs A10I to A180.
Source: ACIL Allen Consulting

The split of peak/off peak consumption for residential customers is shown in Table 4. This also details the implementation of post-model adjustments. Time of use pricing has the effect of transferring a significant quantity of consumption from peak to off-peak periods.[2] The impact of solar PV on consumption is limited to peak periods in this table. This is not to say that solar PV systems do not operate outside peak periods, for example they operate on weekend days which are classified as off peak for certain tariffs. However, given that tariff A10I is closed to new entrants, additional customers with PV systems are assumed to join tariff A100, which does not distinguish between peak and off peak times. Hence, from a tariff perspective, solar PV systems have no impact on off peak consumption.

Table 4 **Peak/off-peak residential consumption forecasts, 2016-2020**

	2016	2017	2018	2019	2020
	GWh	GWh	GWh	GWh	GWh
Peak period consumption					
Baseline	1,215	1,236	1,257	1,279	1,301
Flexible pricing	-4	-4	-5	-5	-5
Solar PV	-8	-11	-14	-18	-21
Adjusted peak	**1,204**	**1,221**	**1,238**	**1,257**	**1,275**
Off-peak period consumption					
Baseline	96	99	101	104	107
Flexible pricing	4	4	5	5	5
Solar PV	0	0	0	0	0
Adjusted off-peak	**100**	**103**	**106**	**109**	**112**
Total	**1304**	**1323**	**1344**	**1366**	**1387**

Source: ACIL Allen Consulting

[2] Within this analysis of the TOU pricing impact, 'off peak' is defined as any consumption that is not within 'peak' periods within the A10X tariff class.

A breakdown of the consumption forecasts by time period and tariff is provided in Table 5.

Table 5 **Residential consumption forecasts by billing block type and tariff, 2016-2020**

	2016	2017	2018	2019	2020
	GWh	GWh	GWh	GWh	GWh
			Peak period consumption		
A100	1,175.7	1,196.7	1,218.4	1,241.7	1,264.3
A10X (Summer)	0.3	0.3	0.4	0.4	0.5
A10X (Winter)	0.3	0.3	0.4	0.4	0.4
A10I	33.0	32.6	32.2	31.8	31.3
A140	6.2	5.8	5.4	5.0	4.6
A180	0.0	0.0	0.0	0.0	0.0
			Shoulder period consumption		
A100	0.0	0.0	0.0	0.0	0.0
A10X (Summer)	0.6	0.7	0.8	1.0	1.1
A10X (Winter)	0.6	0.7	0.9	1.0	1.1
A10I	0.0	0.0	0.0	0.0	0.0
A140	0.0	0.0	0.0	0.0	0.0
A180	0.0	0.0	0.0	0.0	0.0
			Off-peak period consumption		
A100	0.0	0.0	0.0	0.0	0.0
A10X (Summer)	0.4	0.4	0.5	0.6	0.6
A10X (Winter)	0.4	0.4	0.5	0.6	0.6
A10I	36.7	38.3	39.9	41.6	43.3
A140	7.1	6.8	6.6	6.3	5.9
A180	50.1	51.1	52.2	53.4	54.5
Total	**1,261**	**1,283**	**1,306**	**1,330**	**1,354**

Source: ACIL Allen Consulting

2.1.2 Residential customer numbers

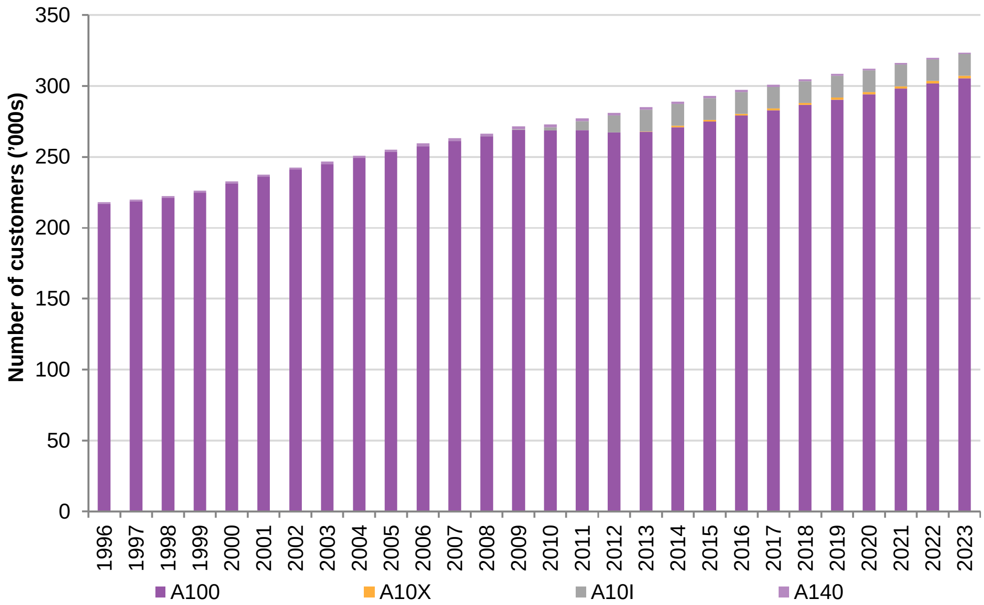
The forecasts of residential customer numbers are shown in Table 6 and Figure 4. Tariffs A100 and A10X are projected to grow over the period, though most of this growth is on A100. This reflects the assumed rates of migration to flexible pricing, which is discussed in chapter 7. Tariffs A10I and A140 are assumed not to grow in customer numbers, as they are closed to new entrants.

Table 6 **Forecast residential customer numbers by tariff, 2016 to 2020**

	2016	2017	2018	2019	2020
A100	279,096	282,762	286,489	290,277	294,129
A10X	1,200	1,300	1,400	1,500	1,600
A10I	15,285	15,280	15,276	15,272	15,269
A140	1,553	1,474	1,392	1,308	1,222
Residential customers	**297,134**	**300,815**	**304,556**	**308,357**	**312,220**

Source: ACIL Allen Consulting

Figure 4 **Residential customer numbers by tariff, Actual from 1996 to 2013, forecast from 2014 to 2020**



Note: Figures up to 2013 are actual consumption. From 2014 onwards figures pertain to forecast consumption.

Source: ACIL Allen Consulting

2.1.3 Consumption per average residential customer

The forecasts of consumption per average residential customer are shown in Table 7 and Figure 5. These forecasts were estimated at the tariff class level, so they are not broken down to individual tariffs. These are an intermediate step in producing the aggregate forecasts set out in section 2.1.1.

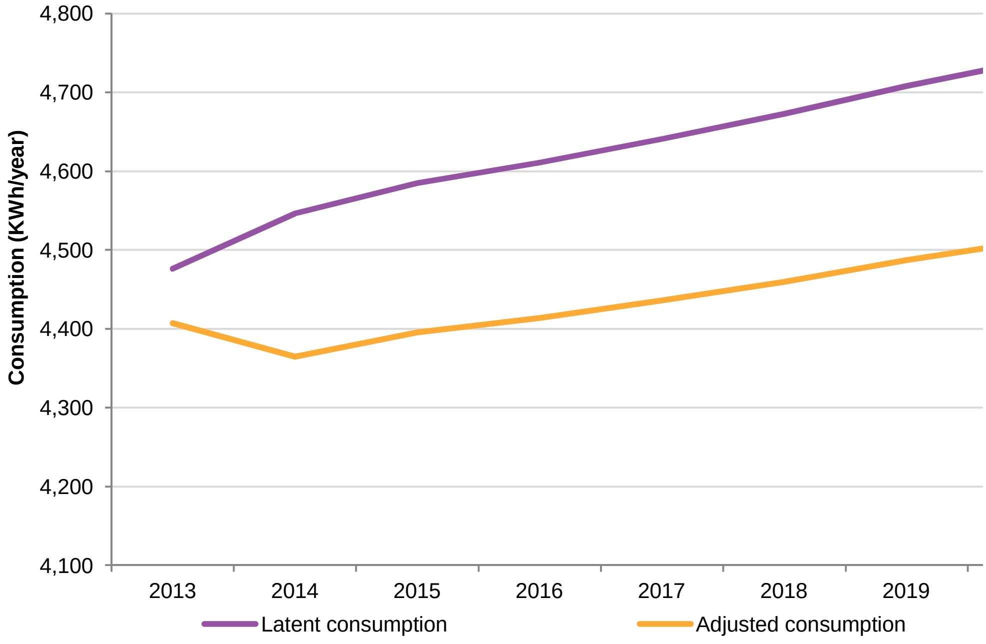
Table 7 **Forecast consumption per average residential customer, actual 2013, and forecast 2014 to 2020**

	2013	2014	2015	2016	2017	2018	2019	2020
	kWh/ cust/ year							
Latent consumption per average residential customer	4,476	4,546	4,585	4,611	4,641	4,673	4,708	4,739
Adjusted consumption per average residential customer	4,407	4,365	4,396	4,414	4,436	4,460	4,487	4,511

Note: 2013 is actual consumption per customer. From 2014 onwards figures pertain to forecast consumption per customer.

Source: ACIL Allen Consulting

Figure 5 **Forecast consumption per average residential customer, actual 2013, and forecast 2014 to 2020**



Note: 2013 is actual consumption per customer. From 2014 onwards figures pertain to forecast consumption per customer.
Source: ACIL Allen Consulting

2.1.4 Change to tariff structure

From 2017 JEN intends to transition its residential customers from their current volume based tariff to a tariff that incorporates a maximum demand component. ACIL Allen analysed the monthly 2013 maximum demand of all of JEN's residential customers for which a full year of data were available (i.e. all whose smart meter had was installed before January 2013).

The maximum demands observed in that sample were projected forwards at the same growth rate as was applied to the energy consumption forecasts. The results in Table 8 are reflect the average maximum demand of JEN's customers averaged across the twelve months of each year (i.e. the average monthly maximum demand). These will understate the typical maximum annual demand of residential customer because maximum demand is lower in some months than others.

Table 8 **Maximum demand – residential tariffs**

Tariff	2016	2017	2018	2019	2020
		Residential			
A100	N/A	836	851	867	883
A10X	N/A	4	5	5	5
A10I	N/A	51	52	53	54
A140	N/A	5	4	4	4
A180	N/A	0	0	0	0
Total residential	**N/A**	**896**	**912**	**930**	**946**

Source: ACIL Allen Consulting

2.2 Non-residential forecasts

2.2.1 Non-residential consumption

Forecasts of non-residential consumption are provided in Table 9 and Figure 6, with growth rates shown in Figure 7. Non-residential consumption forecasts were not subject to post model adjustments.

Total non-residential consumption is forecast to grow by 115 GWh, or 3.8 per cent, between 2016 and 2020. The largest component of consumption is large LV. However, the most significant growth in consumption comes from small business, which is forecast to increase by 9.4 per cent over the period.

Consumption in the large HV and large ST categories was not forecast econometrically because it is dominated by a small number of very large customers. Forecasts in these categories were based on information made available to ACIL Allen on future changes that JEN considers being likely to occur. The only change in forecast consumption in these tariff categories relates to the closure of the Ford manufacturing plant in Broadmeadows in late 2016.[3]

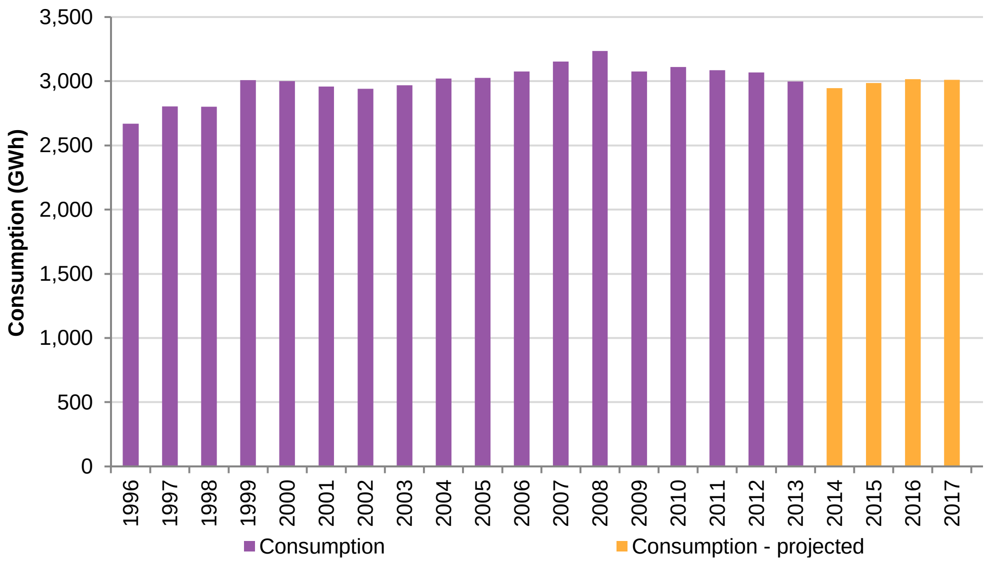
[3] One quarter of this impact is applied to consumption from 2016, and three quarters to consumption from 2017.

Table 9 **Non-residential consumption forecasts, 2016 to 2020**

Tariff	2016	2017	2018	2019	2020
	GWh	GWh	GWh	GWh	GWh
Small business					
A200	177.8	177.3	177.1	176.9	176.8
A210	318.8	331.3	344.9	359.1	374.3
A230	93.4	93.8	94.2	94.7	95.2
A250	62.1	63.5	65.1	66.8	68.6
A270	27.6	27.5	27.4	27.4	27.4
A290	54.4	55.9	57.5	59.2	61.0
Total small business	**734.2**	**749.4**	**766.3**	**784.0**	**803.4**
Large business - LV					
A300	323.4	331.8	340.3	348.9	357.7
A30E	10.8	12.0	13.2	14.4	15.6
A320	498.9	508.1	517.3	526.7	536.3
A32E	40.6	46.9	53.3	59.7	66.2
A340	173.3	161.1	148.7	136.3	123.8
A34M	17.1	15.4	13.8	12.1	10.4
A34E	32.4	33.9	35.5	37.0	38.6
A370	89.8	90.0	90.1	90.3	90.5
A37M	125.2	133.5	141.9	150.4	159.0
Total large LV	**1,311.6**	**1,332.6**	**1,354.1**	**1,375.9**	**1,398.2**
Large business - HV					
A400	459.3	461.9	464.5	467.0	469.6
A40E	21.6	23.7	25.8	27.9	30.0
A40R	81.6	77.0	72.4	67.8	63.2
A42E	0.0	0.0	0.0	0.0	0.0
A480	98.6	57.3	57.2	57.1	57.0
Total large HV	**661.1**	**619.9**	**619.9**	**619.9**	**619.9**
Large business - ST					
A500	162.8	162.8	162.8	162.8	162.8
A50A	143.1	143.1	143.1	143.1	143.1
A50E	1.7	1.7	1.7	1.7	1.7
Total large ST	**307.5**	**307.5**	**307.5**	**307.5**	**307.5**
Total non-residential consumption	**3,014.5**	**3,009.4**	**3,047.8**	**3,087.4**	**3,129.0**

Source: ACIL Allen Consulting

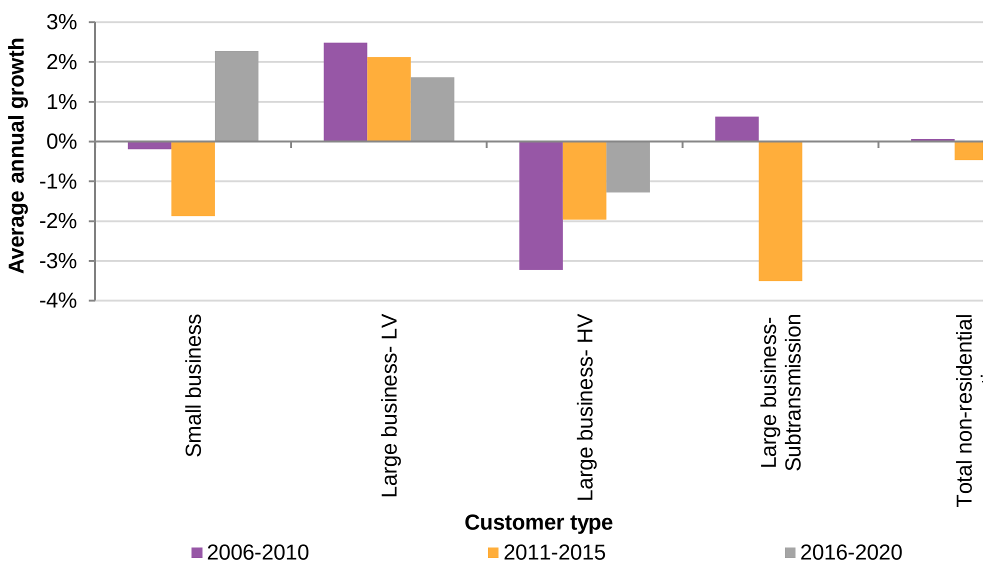
Figure 6 **Non residential consumption, actual 1996 to 2013, forecast 2014 to 2020**



Note: Figures up to 2013 are actual consumption. From 2014 onwards figures pertain to forecast consumption.

Source: ACIL Allen Consulting

Figure 7 **Average annual growth by tariff type, 2006 to 2020**



Note: Average annual growth refers to the compound average growth rate of each tariff between the start and end years of each period.

Source: ACIL Allen Consulting

The forecast split of non-residential consumption between peak and off-peak periods is shown at the tariff level in Table 10 and Table 11. Over the period 2016 to 2020, the proportion of energy consumed in peak periods is forecast to decrease from 59.4 per cent, to 58.5 per cent. The change is most significant for small business, which decreases from 69.7 per cent peak consumption, to 67.9 per cent. Large ST customers exhibit the smallest change, from 49.4 per cent in 2016, to 49.2 per cent in 2020.

Table 10 **Non-residential consumption forecasts – Peak periods, 2016-2020**

Tariff	2016	2017	2018	2019	2020
	GWh	GWh	GWh	GWh	GWh
Small business					
A200	177.8	177.3	177.1	176.9	176.8
A210	192.8	199.3	206.3	213.6	221.5
A230	54.3	54.3	54.3	54.3	54.4
A250	46.4	47.2	48.1	49.0	50.1
A270	21.4	21.4	21.4	21.4	21.4
A290	18.1	18.6	19.1	19.6	20.2
Total small business	**511**	**518**	**526**	**535**	**544**
Large business - LV					
A300	199.4	204.7	210.1	215.5	221.1
A30E	5.7	6.0	6.2	6.4	6.5
A320	291.2	294.8	298.5	302.3	306.0
A32E	23.1	26.3	29.6	32.7	35.9
A340	99.8	92.9	86.0	79.0	71.9
A34M	9.7	8.6	7.6	6.5	5.5
A34E	18.2	18.6	19.0	19.3	19.6
A370	48.1	48.0	47.9	47.8	47.7
A37M	70.3	74.8	79.4	84.1	88.7
Total large LV	**765**	**775**	**784**	**794**	**803**
Large business - HV					
A400	250.8	250.7	250.5	250.4	250.2
A40E	11.6	12.7	13.7	14.7	15.7
A40R	43.7	41.2	38.6	36.1	33.6
A42E	0.0	0.0	0.0	0.0	0.0
A480	54.4	29.3	29.6	30.0	30.3
Total large HV	**361**	**334**	**333**	**331**	**330**
Large business - ST					
A500	77.9	77.9	77.9	77.9	77.9
A50A	73.1	73.0	72.9	72.8	72.6
A50E	0.8	0.8	0.8	0.8	0.8
Total large ST	**152**	**152**	**152**	**151**	**151**
Total non-residential peak consumption	**1,789**	**1,778**	**1,794**	**1,811**	**1,828**

Source: ACIL Allen Consulting

Table 11 **Non-residential consumption forecasts – Non-peak periods, 2016-2020**

Tariff	2016	2017	2018	2019	2020
	GWh	GWh	GWh	GWh	GWh
		Small business			
A200	0.0	0.0	0.0	0.0	0.0
A210	126.0	132.1	138.6	145.5	152.9
A230	39.2	39.5	39.9	40.4	40.8
A250	15.7	16.4	17.1	17.8	18.6
A270	6.1	6.1	6.0	6.0	6.0
A290	36.3	37.3	38.4	39.6	40.8
Total small business	**223**	**231**	**240**	**249**	**259**
		Large business - LV			
A300	123.9	127.0	130.2	133.4	136.6
A30E	5.2	6.1	7.0	8.0	9.1
A320	207.8	213.2	218.8	224.5	230.3
A32E	17.5	20.6	23.7	26.9	30.3
A340	73.5	68.1	62.7	57.3	52.0
A34M	7.4	6.8	6.2	5.6	4.9
A34E	14.2	15.3	16.5	17.7	19.0
A370	41.7	42.0	42.3	42.5	42.8
A37M	54.9	58.6	62.5	66.3	70.3
Total large LV	**546**	**558**	**570**	**582**	**595**
		Large business - HV			
A400	208.5	211.2	213.9	216.7	219.4
A40E	10.0	11.0	12.1	13.2	14.3
A40R	37.9	35.8	33.8	31.7	29.6
A42E	0.0	0.0	0.0	0.0	0.0
A480	44.2	28.0	27.6	27.1	26.7
Total large HV	**301**	**286**	**287**	**289**	**290**
		Large business - ST			
A500	84.9	84.9	84.9	84.9	84.9
A50A	69.9	70.0	70.2	70.3	70.4
A50E	0.9	0.9	0.9	0.9	0.9
Large ST	**156**	**156**	**156**	**156**	**156**
Total non-residential off-peak consumption	**1,226**	**1,231**	**1,253**	**1,276**	**1,301**

Source: ACIL Allen Consulting

2.2.2 Non-residential customer numbers

The forecast number of customers on non-residential tariffs are shown at the tariff level in Table 12.

Table 12 **Forecast non-residential customer numbers by tariff, 2016 to 2020**

Tariff	2016	2017	2018	2019	2020
			Small business		
A200	15,640	15,922	16,208	16,499	16,794
A210	8,124	8,139	8,153	8,166	8,179
A230	555	572	590	607	625
A250	2,433	2,405	2,375	2,345	2,313
A270	129	129	129	129	129
A290	0	0	0	0	0
Total small business	**26,881**	**27,167**	**27,455**	**27,747**	**28,041**
			Large business - LV		
A300	849	886	924	964	1,006
A30E	43	49	55	61	68
A320	363	362	362	361	359
A32E	36	42	47	54	60
A340	56	54	51	48	45
A34M	13	12	11	10	9
A34E	13	14	15	16	17
A370	18	18	19	19	19
A37M	33	32	32	32	32
Total large LV	**1,423**	**1,469**	**1,516**	**1,565**	**1,616**
			Large business - HV		
A400	69	69	69	69	69
A40E	3	3	3	4	4
A40R	4	4	4	3	3
A42E	0	0	0	0	0
A480	2	1	1	1	1
Total large HV	**78**	**77**	**77**	**77**	**77**
			Large business - ST		
A500	1	1	1	1	1
A50A	1	1	1	1	1
A50E	1	1	1	1	1
Large ST	**3**	**3**	**3**	**3**	**3**
Total non-residential off-peak consumption	**28,385**	**28,715**	**29,051**	**29,392**	**29,737**

Source: ACIL Allen Consulting

Consistent with recent trends, large LV customer numbers are forecast to grow the fastest, with 13.6 per cent growth in the number of these customers from 2016 to 2020. The number of large HV customers is forecast to decline by one customer throughout this period due to the closure of the Ford manufacturing facility.

2.2.3 Billed demand

The forecasts of billed contract demand are shown in Table 13. These include the effect of JEN's intention to:

- conduct a demand reset scheduled for 2016
- transition all small business customers to demand tariffs from 2017 (only A230 and A270 include a demand component at present)
- transition large business customers from MW to MVA tariffs from 2017.

Table 13 **Forecast billed demand - 2016 to 2020**

Tariff	2016	2017	2018	2019	2020
Small business					
A200	N/A	673.07	672.15	671.22	670.96
A210	N/A	345.80	359.99	374.77	390.65
A230	38.85	39.02	39.24	39.46	39.73
A250	N/A	144.22	147.84	151.62	155.76
A270	12.56	12.72	12.91	13.11	13.32
A290		-	-	-	-
Total small business	**51.4**	**1214.8**	**1214.8**	**1214.8**	**1214.8**
Large LV					
	MW	**MVA**	**MVA**	**MVA**	**MVA**
A300	147.3	174.57	179.22	183.94	188.74
A30E	8.5	11.33	12.39	13.46	14.53
A320	172.7	200.31	203.89	207.53	211.23
A32E	17.4	20.71	23.32	25.97	28.64
A340	45.5	47.44	43.22	38.99	34.72
A34M	8.9	9.36	8.27	7.18	6.09
A34E	10.9	11.86	12.34	12.83	13.32
A370	20.9	24.21	24.26	24.32	24.37
A37M	34.8	42.35	44.95	47.57	50.22
Total large LV	**467.0**	**542.1**	**551.9**	**561.8**	**571.9**
Large HV					
	MW	**MVA**	**MVA**	**MVA**	**MVA**
A400	157.3	174.83	175.78	176.73	177.67
A40E	5.8	6.44	6.98	7.51	8.04
A40R	20.0	21.39	20.11	18.84	17.57
A42E	N/A	N/A	N/A	N/A	N/A
A480	24.3	11.28	11.26	11.24	11.21
Total large HV	**207.5**	**213.9**	**214.1**	**214.3**	**214.5**
Large ST					
	MW	**MVA**	**MVA**	**MVA**	**MVA**
A500	26.8	33.12	33.12	33.12	33.12
A50A	27.8	30.78	30.78	30.78	30.78
A50E	15.0	21.07	21.07	21.07	21.07
Total large ST	**69.6**	**85.0**	**85.0**	**85.0**	**85.0**

Source: ACIL Allen Consulting

3 Historical data - consumption and customer numbers

This chapter provides an overview of the history of consumption and customer numbers in JEN's region. The data series presented in this section were used as the dependent variables in the regression models described in chapter 5.

3.1 Consumption

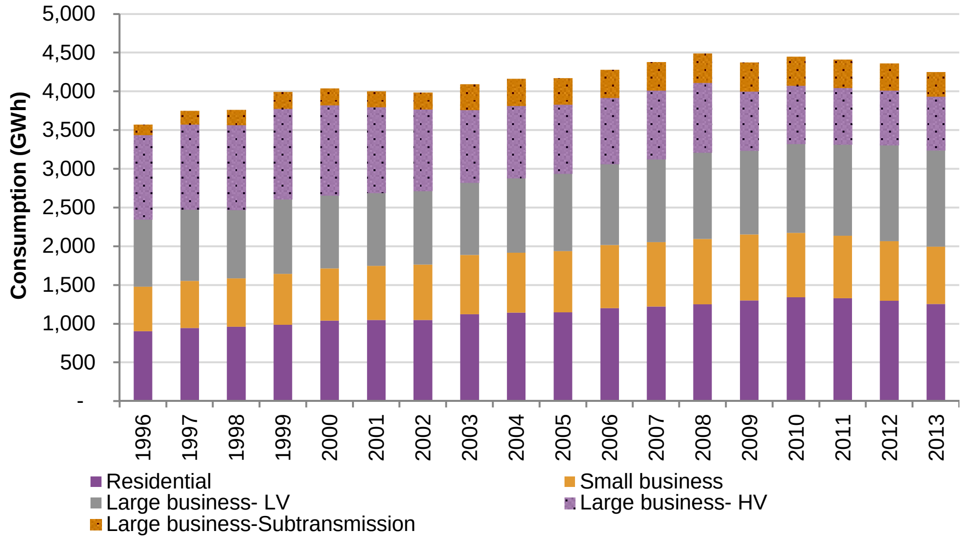
Figure 8 shows the historical consumption in JEN's distribution region from 1996 to 2013 by tariff class.

Consumption was characterised by steady growth from 1996 until 2008, when it began to decline. Likely causes of the decline include:

- slower economic growth
- higher electricity prices
- increased solar PV uptake.

In 2013 total consumption across the JEN network was 4,250 GWh.

Figure 8 **Total consumption by tariff class, 1996 to 2013**



Data source: JEN

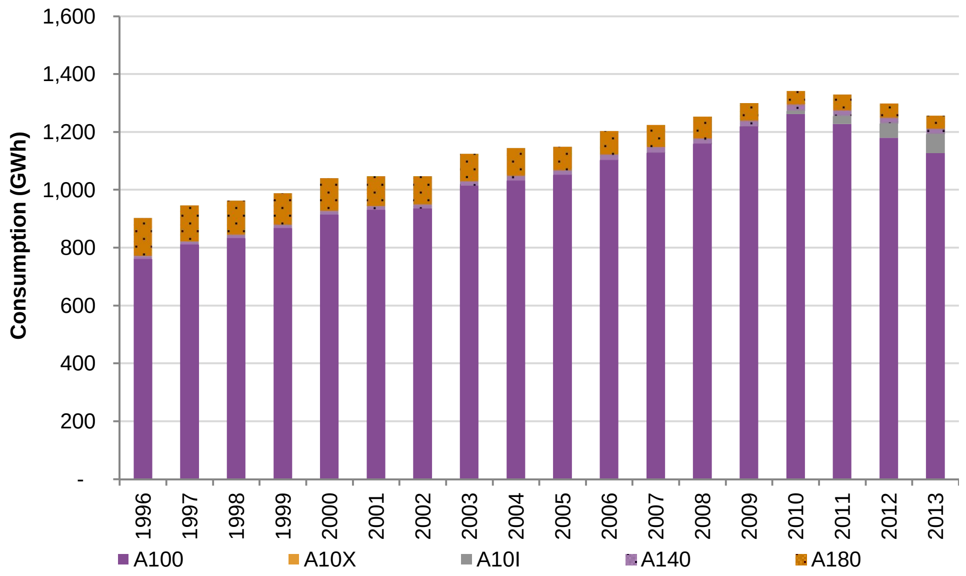
The largest customer class by consumption, which was residential, accounted for 29.5 per cent of all consumption in 2013. This was closely followed by large LV, which accounted for 29.3 per cent of total consumption.

In 2013, small business made up 17.4 per cent of consumption while large HV made up 16.4 per cent of total consumption. Large ST accounted for the remaining 7.4 per cent of total consumption.

3.1.1 Residential consumption

Figure 9 shows the historical residential consumption in JEN's distribution region. It shows that annual residential consumption increased steadily from 1996 to a peak of 1,340 GWh in 2010. It then declined in each of the subsequent three years. In 2013, residential consumption was 1,260 GWh.

Figure 9 **Residential consumption by tariff, 1996 to 2013**



Data source: JEN

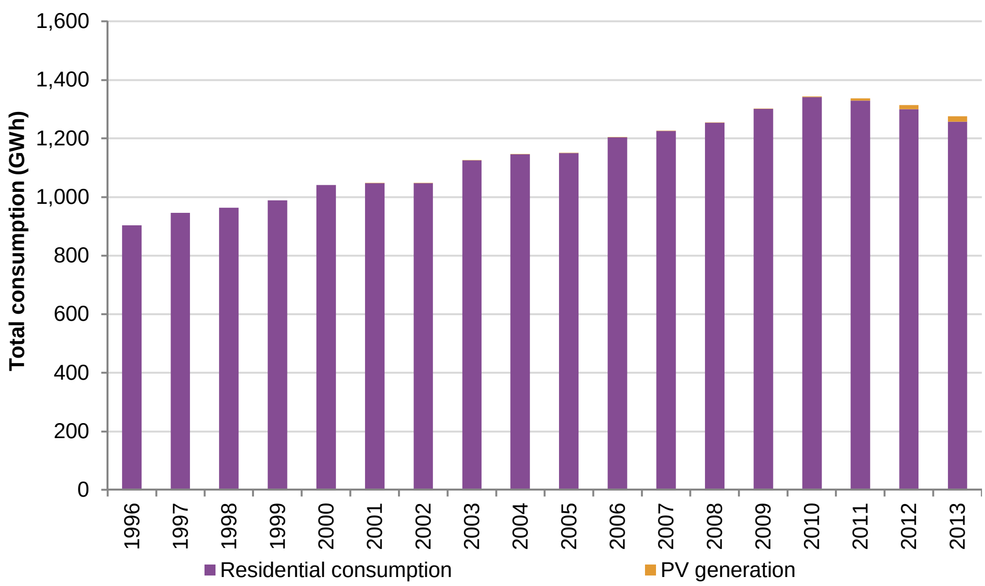
For modelling purposes residential consumption was altered to 'add back' the estimated quantity of consumption avoided through the use of solar PV systems. This energy was consumed, but is not seen by the meters from which the historical data were collected. It was added back to the consumption figures observed from the meters to reveal latent consumption, which was fed through to the econometric models.

The quantity of energy to be added back was calculated using an approach consistent with that used to estimate the take-up of PV systems (see chapter 6), though for this step the task was simpler. The process was to:

- estimate the total output of solar PV systems in JEN's region using data pertaining to total installed capacity and the Clean Energy Regulator's output factor for Victoria
- estimate the proportion of this energy that is exported to the grid (and thus observed on the meters) using the process described in chapter 6
- add the remaining energy back to the total residential consumption.

The result was that the historical series of residential consumption that fed into the model was the sum of the two shown in Figure 10.

Figure 10 **Residential consumption and PV energy generation, 1996 to 2013**



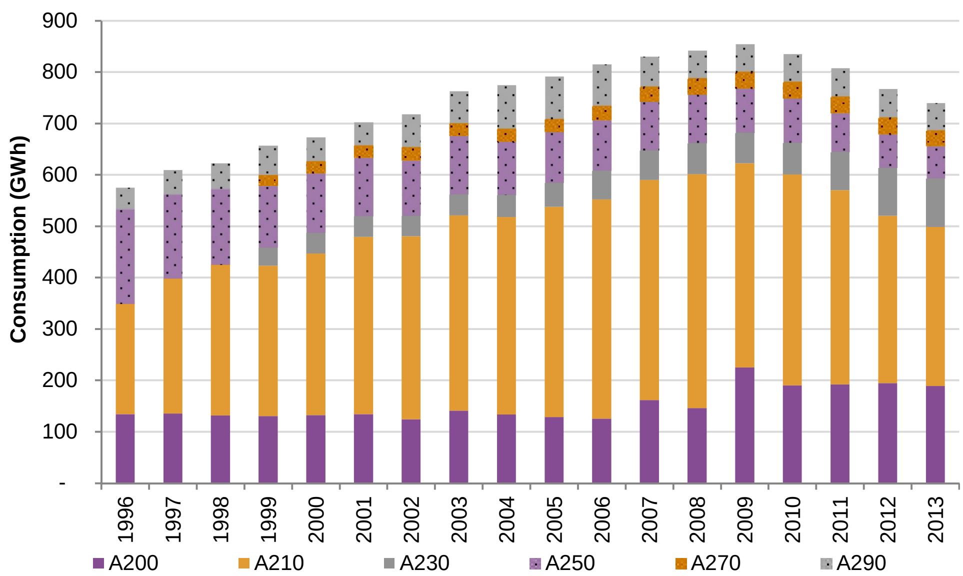
Source: ACIL Allen Consulting and JEN

3.1.2 Small business consumption

Figure 11 shows historical consumption by small business tariff class in JEN's region. Similarly to residential consumption, small business consumption increased steadily from 1996 to 2009, peaking at 854 GWh. It then declined for four consecutive years.

Likely reasons for the decline are the onset of the GFC combined and significant electricity price increases for small business customers.

Figure 11 **Small business consumption by tariff, 1996 to 2013**

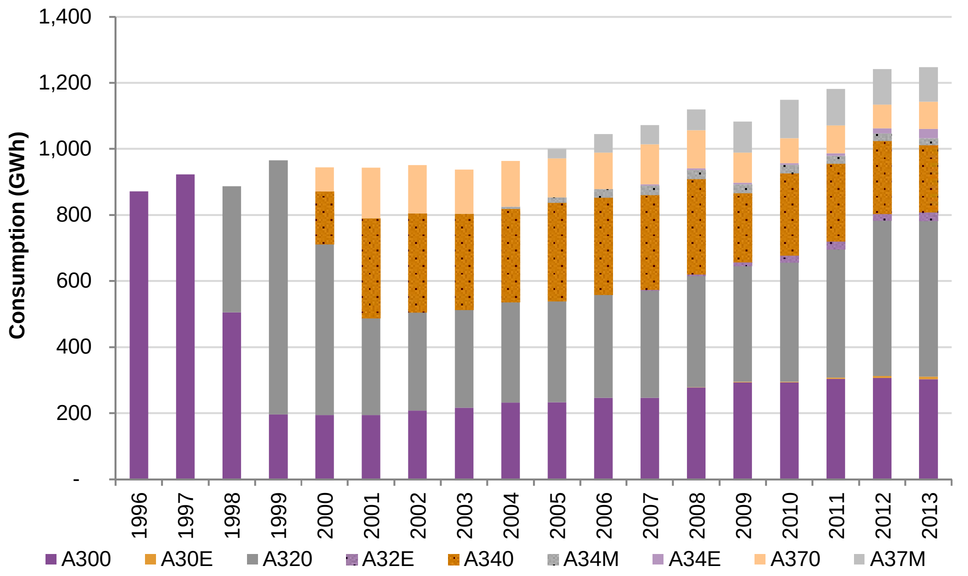


Data source: JEN

3.1.3 Large LV consumption

Figure 12 shows historical consumption by large LV customer tariff class in JEN's region. The figure shows that consumption for this class remained largely stable from 1996 to 2004, before commencing an upward trajectory to 2013. In 2013, total consumption for this class was 1,250 GWh.

Figure 12 **Large LV consumption by tariff, 1996 to 2013**

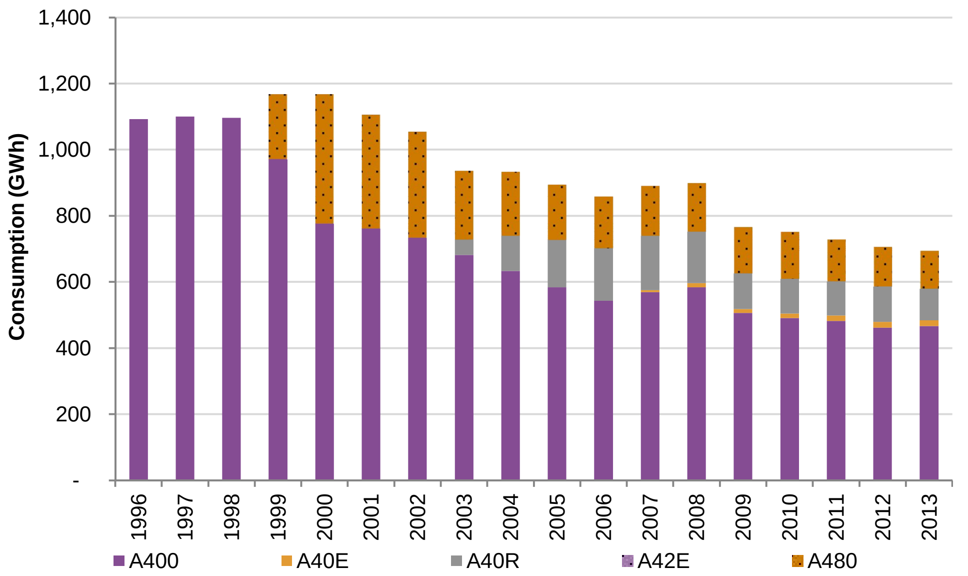


Data source: JEN

3.1.4 Large HV consumption

Figure 13 shows historical consumption by the large HV customer tariff class in JEN's region. It displays a steady decline in consumption from 1999 to 2013. In 2013 large HV consumption was 696 GWh.

Figure 13 **Large HV consumption by tariff, 1996 to 2013**

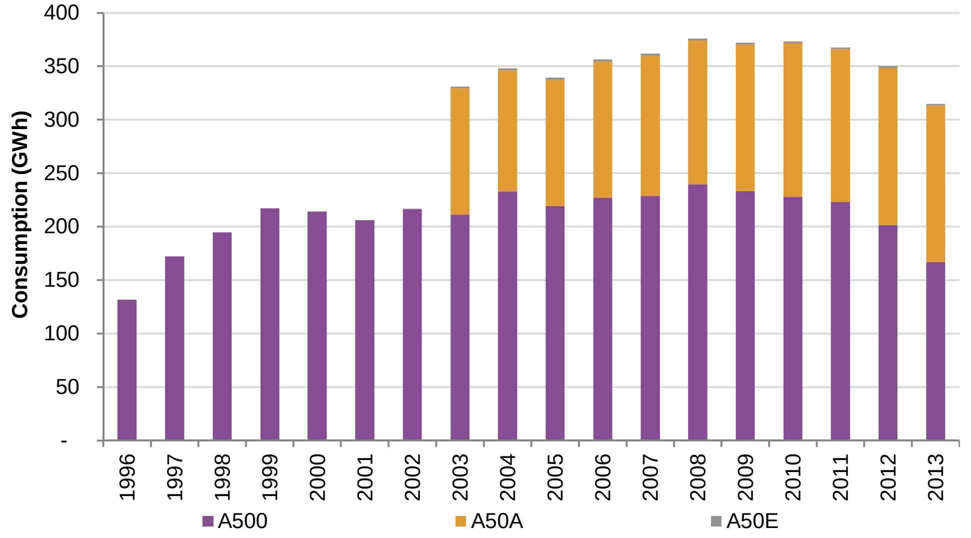


Data source: JEN

3.1.5 Large ST consumption

Figure 14 shows the historical consumption of the large ST tariff class in JEN's region. Consumption in this category is driven by a very small number of customers, so large discrete shifts in total consumption will occur when a new customer connects to or disconnects from the network, which appears to have happened in 2003. In 2013, large ST consumption was 315 GWh.

Figure 14 **Large business - ST consumption by tariff, 1996 to 2013**



Data source: JEN

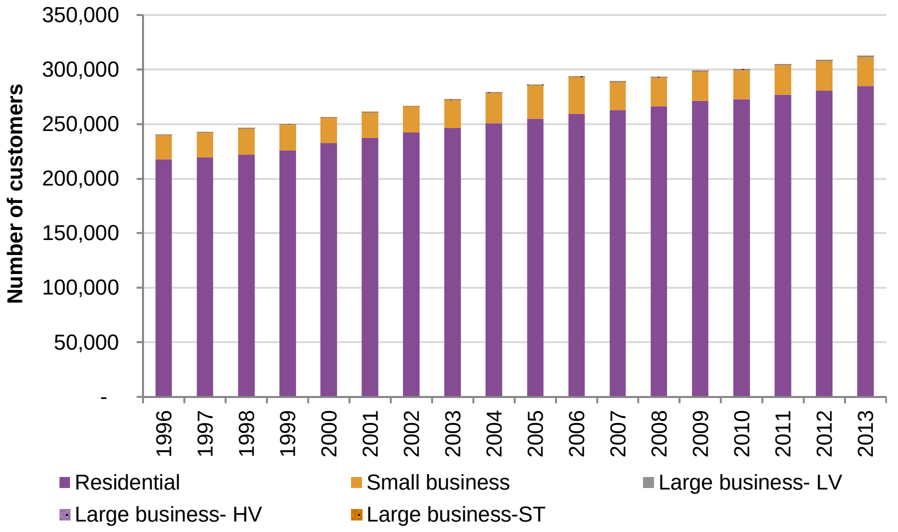
3.2 Customer numbers

Figure 15 shows the number of customers supplied by the JEN distribution network.

The figure indicates a steady increase in customer numbers over time. This is reflective of the number of households serviced by the network increasing, as well as the number of businesses servicing these households. Since 1996, growth in customer numbers has averaged 1.55 per cent per annum.

In 2013, JEN had 312,530 customers. Of these, 285,040 were residential, 26,093 were small business, 1,316 were large LV, 79 were large HV, and 3 were large ST customers.

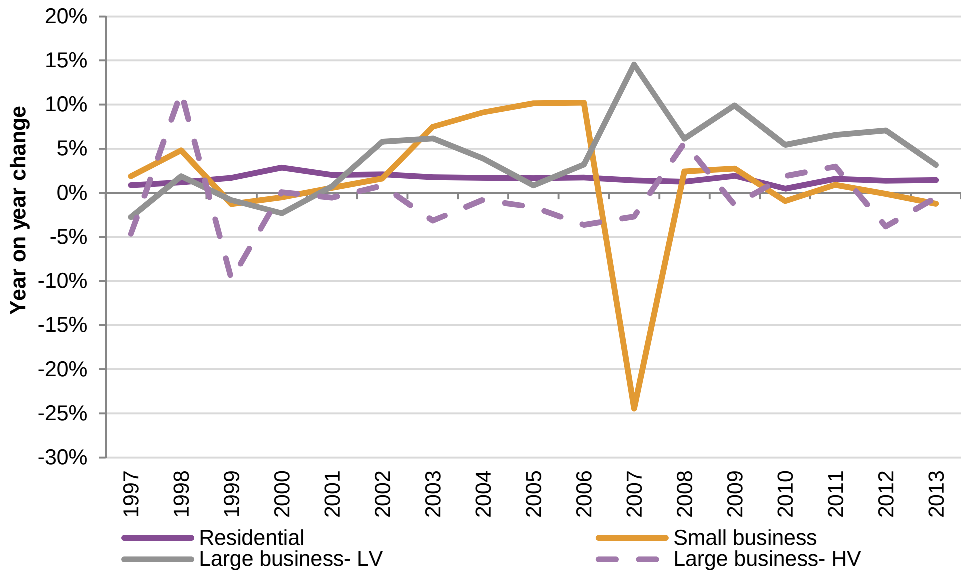
Figure 15 **Total customer numbers by tariff class, 1996 to 2013**



Data source: JEN

Figure 16 shows year on year changes in customer numbers by tariff class from 1997 to 2013. There is the significant growth in small business customers from 2003 to 2006, followed by the sharp decline of 25 per cent. This is accounted for in the forecasting process with the use of indicator variables from 2004 to 2006.

Figure 16 **Year on year change in customer numbers by tariff class, 1997 to 2013**



Source: ACIL Allen Consulting

4 Drivers of consumption

This chapter provides an overview of the history of likely drivers of consumption in JEN's region. Data series that are discussed are:

- economic activity - section 4.1
- customer numbers - in section 4.2
- weather - section 4.3
- electricity prices - in section 4.4.

The historical data series presented in these sections were used as the dependent (X) variables in the regression models described in chapter 5. The projections of drivers presented in this chapter were used as inputs into the baseline forecasts.

4.1 Economic activity

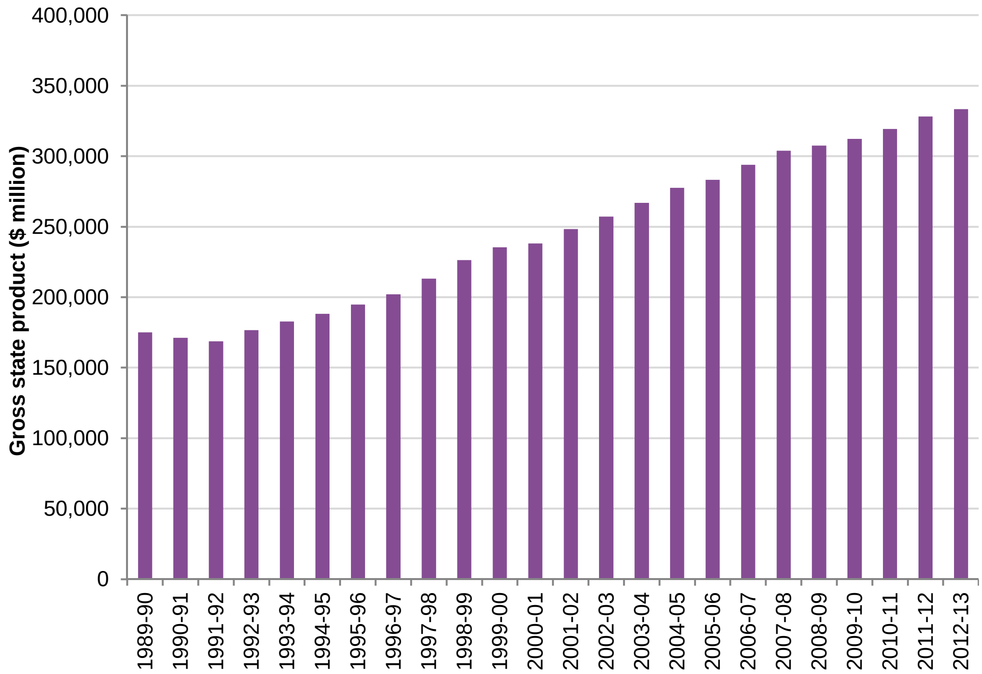
Growth in economic activity is a major driver of rising incomes. Consumption of electricity is, in part, driven by higher disposable incomes and subsequent demand for new electronic appliances and equipment, as well as increasing commercial and industrial activity.

In addition to this, there is typically a strong relationship between economic output and electricity consumption given that electricity is an important input into many industries.

Figure 17 shows the historical time series of Victorian economic activity, as measured by Gross State Product (GSP), from 1989-90 to 2012-13.[4]

[4] GSP growth is forecast on a financial year basis. Therefore, for consistency of presentation we present history on a financial year basis as well. However, JEN's regulatory periods are based on calendar years. Therefore GSP growth is rebased to calendar years for modelling purposes.

Figure 17 **Victorian Gross State Product (GSP), 1989-90 to 2012-13, $m (chain volume measure)**



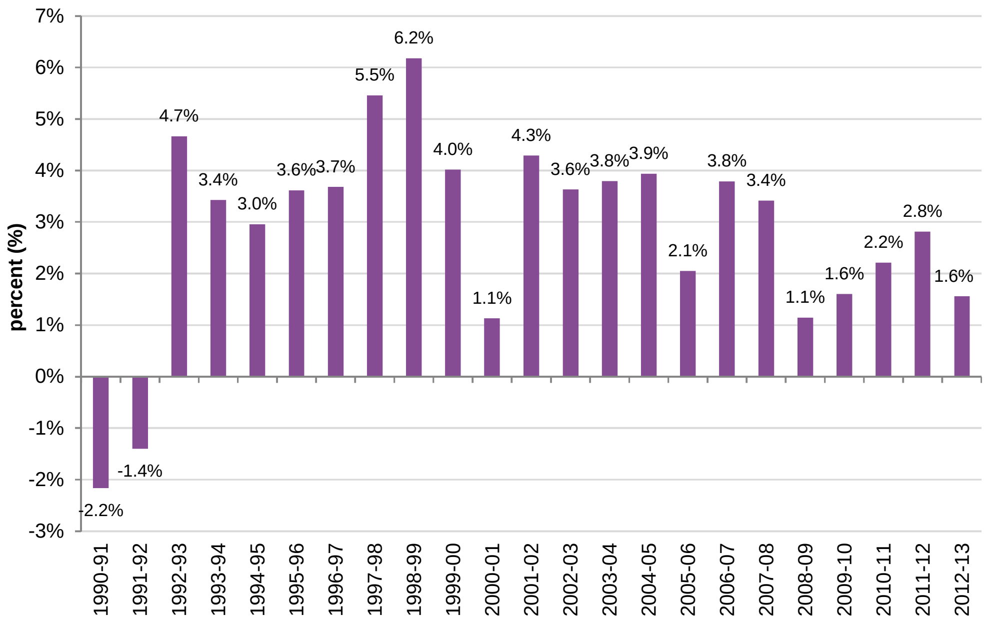
Note: GSP figures are for financial years. This was mapped to calendar years by taking an average of the appropriate financial years for each calendar year.

Source: ABS, 5220.0 Australian National Accounts: State Accounts

Victorian economic growth has been positive in all but two years since 1989-90. In 1990-91 Victorian GSP declined by 2.2 per cent. This was followed by a further decline of 1.4 per cent in 1991-92 (see Figure 18).

Victorian GSP growth slowed in the period following 2008-09. In the five years since then it has averaged just 1.9 per cent per annum. This is compared to a long term average of 2.9 per cent per annum from 1990-91 to 2012-13.

Figure 18 **Year on year GSP growth, Victoria 1990-91 to 2012-13**



Source: ABS, 5220.0 Australian National Accounts: State Accounts

Economic growth forecasts

Several economic growth projections were considered for application to the consumption model developed for JEN. They are summarised in Table 14.

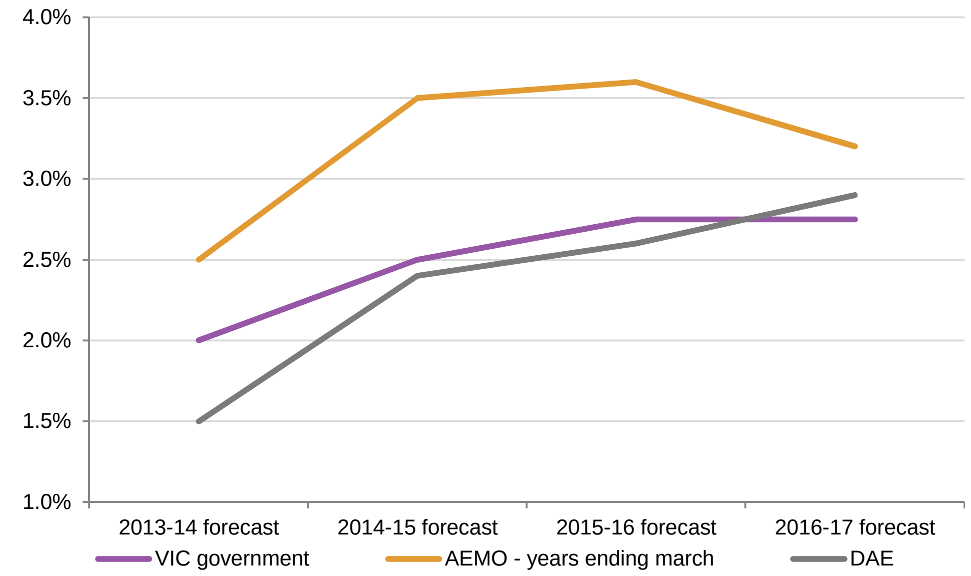
Table 14 **Comparison of Victorian GSP growth forecasts, 2013-14 to 2016-17**

Source	2013-14 forecast	2014-15 forecast	2015-16 forecast	2016-17 forecast
Victorian government, budget outlook 2014, page 13	2.0%	2.5%	2.75%	2.75%
AEMO, Economic outlook information paper, 2013[a]	~2.5%	~3.5%	~3.6%	~3.2%
Deloitte Access Economics, December 2013[b]	1.5%	2.4%	2.6%	2.9%
NIEIR – low scenario [c]	2.1%	2.9%	N/A	N/A
NIEIR – medium scenario [c]	2.5%	3.6%	N/A	N/A

Sources:
[a] *Economic outlook information paper*, Australian Energy Market Operator, 2013, page 5-24
[b] *Forecast growth in labour costs in Victoria*, Deloitte Access Economics, December, 2013. Figures are gross state output for years ending March.
[c] Obtained from *Economic outlook information paper*, Australian Energy Market Operator, 2013, page 5-2, and related to a report published in 2012.

Figure 10 shows how forecasts from the Victorian Government, the Australian Energy Market Operator, and Deloitte Access Economics compare. The Victorian Government forecasts are the central forecasts of these three sets. They are also the most recently produced set of forecasts that were available. For these reasons they are selected as the basis of GSP forecasts used in the consumption model.

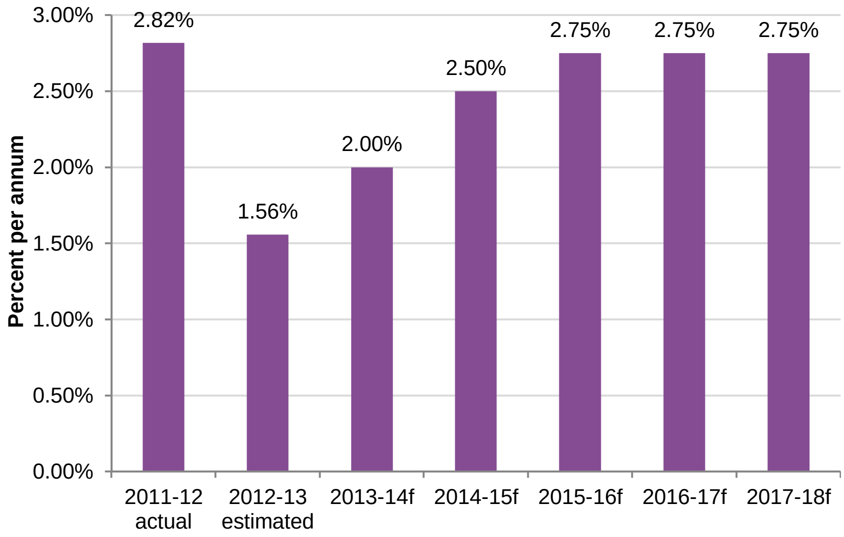
Figure 19 **Victorian GSP growth forecasts, 2013-14 to 2016-17**



Sources:
Victorian Government, budget outlook 2014
Economic outlook information paper, Australian Energy Market Operator, 2013
Forecast growth in labour costs in Victoria, Deloitte Access Economics, December, 2013

According to the Victorian Government's Budget Strategy and Outlook paper 2014-15, Victorian economic growth is expected to revert to close to trend growth over the next four years. Growth in 2013-14 is expected to be 2 per cent, before increasing to 2.50 per cent in 2014-15, and 2.75 per cent in 2015-16 and 2016-17. Beyond this, ACIL Allen assumed that GSP would continue to grow at 2.75 per cent per year.

Figure 20 **Victorian economic growth projections, 2013-14 to 2017-18**



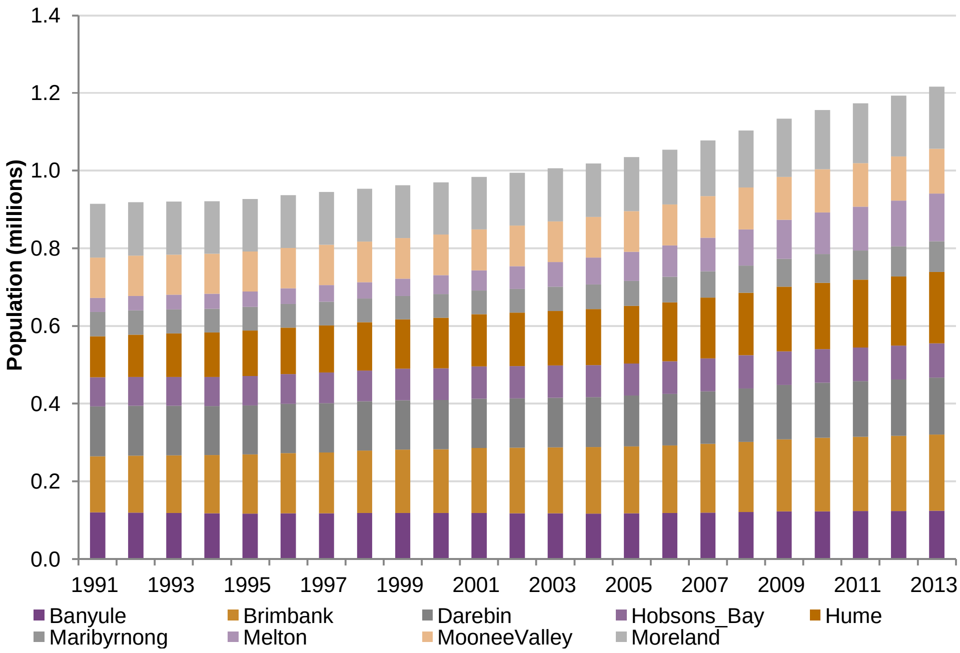
Source: Victorian Government, "Strategy and Outlook 2013-14"

4.2 Customer numbers

Growth in customer numbers has been a key driver of electricity consumption. Increasing residential customer numbers are driven by household formation arising from population growth.

Figure 21 shows the estimated resident population of the JEN region from 1991 to 2013, as per Australian Bureau of Statistics data.

Figure 21 **Estimated resident population, JEN region, 1991 to 2013**



Source: Regional Population Growth, Australia, 2012 (cat. no. 3218.0)

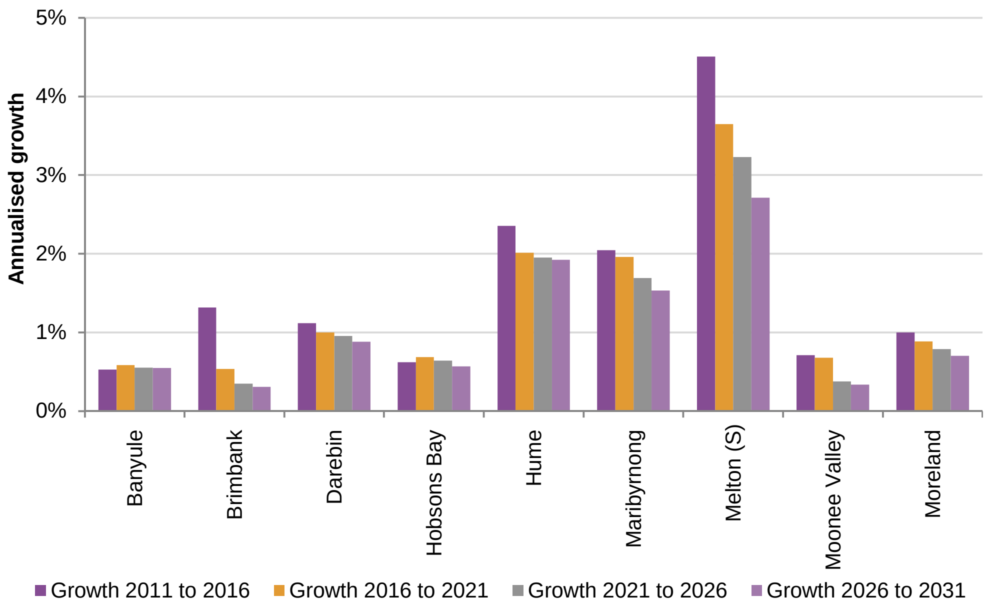
Population growth in the JEN network has averaged 1.3 per cent per annum over the period from 1992 to 2013. In recent years, growth has been stronger, averaging 2 per cent per annum in the last five years.

Residential customer number drivers

JEN's distribution region consists of parts of nine local government areas (LGAs) as shown in Figure 22. The key driver of customer number growth is population growth. However, as Figure 22 shows, this growth varies across LGAs.

Population projections for the relevant LGAs obtained from the Department of Planning and Community Development are shown in Figure 22. The figure shows considerable variation in population growth across LGAs, with Melton, Maribyrnong and Hume displaying strong projected population growth compared to more established areas such as Moreland and Moonee Valley.

Figure 22 **Projected population growth rates for LGAs within JEN's distribution network**

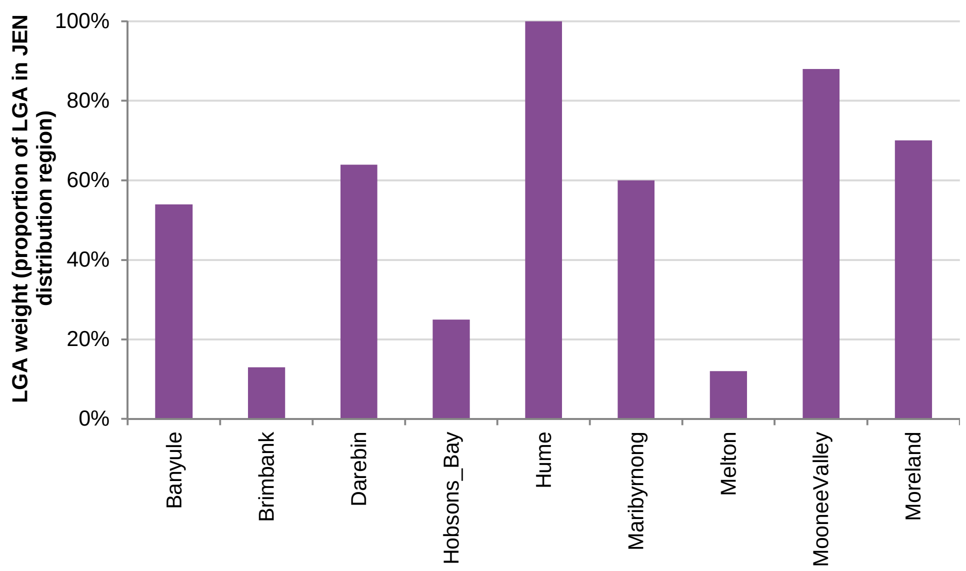


Source: DPCD Victoria in Future 2012

If the growth rates considered above were assumed to have equal influence over population growth in JEN's region, then the forecast could be expected to be pushed up by significant growth in Melton. However, the as can be seen on the map of JEN's distribution region (Figure 1 in chapter 1), some LGAs contribute to growth in customer numbers more than others. For example, only part of Melton sits within JEN's region, so growth there is likely to be less important for JEN than Hume, which is entirely within JEN's region.

The proportion of each LGA that is located within JEN's distribution region is shown in Figure 23.

Figure 23 **Proportion of relevant LGAs within JEN's distribution region**

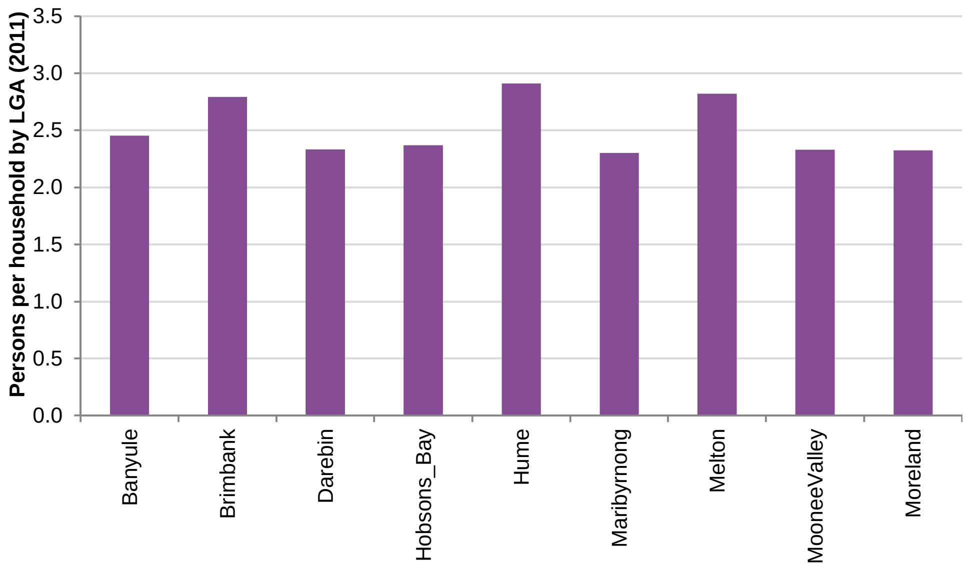


Source: *Electrical sales and customer number forecasts to 2019 for the JEN electricity region*, NIEIR, 2010, Appendix A

Another consideration in deriving customer numbers is the number of individuals per household. Differences across LGAs would mean that the same population growth in two LGAs would lead to different rates of growth in customer numbers.

Figure 24 shows the average number of individuals per household by LGA calculated using data from the 2011 census. These were assumed not to change during the forecast period.

Figure 24 **Persons per household by LGA, 2011**



Source: ACIL Allen Consulting, based on 2011 Census data

4.3 Weather

The weather is a key driver of consumption.

In winter, consumption will vary with weather conditions driven primarily by the ‘heating requirement’. Generally, the cooler a season, the greater the heating requirement, and the greater the consumption.

For present purposes it is necessary to ‘remove’ the effect of weather variations from the historical consumption data. This requires a measure of the heating and cooling requirements in the same historical period as the historical consumption data. Two measures of the heating requirement are currently in use in Australia, namely heating degree days (HDD) and effective degree days (EDD). These two approaches are similar, but differ in the input data they use. EDD is a richer measure that takes account of factors not included in HDD.

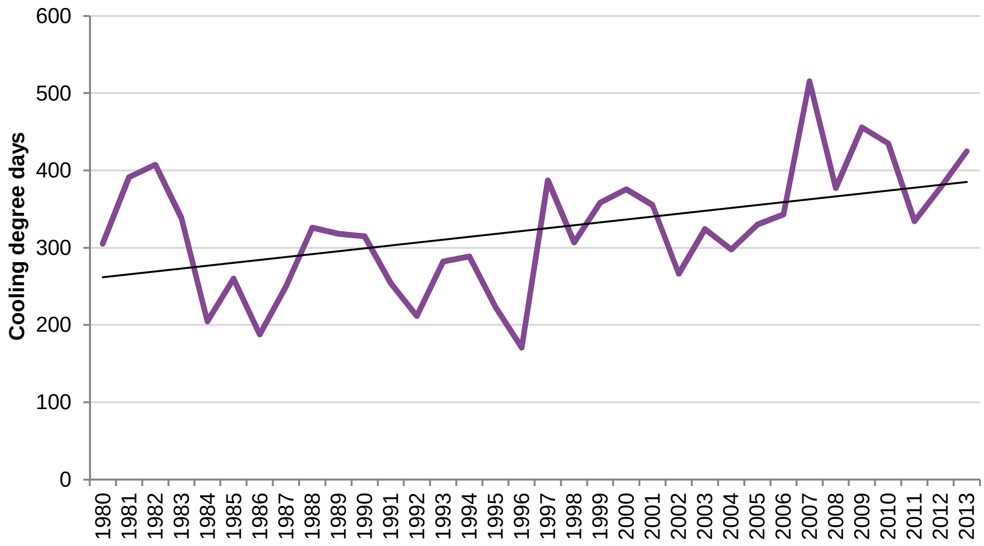
The relationship between weather and consumption is different than the relationship between weather and demand. While a single extreme day is sufficient to result in a season peak demand, that day will make only a small contribution to consumption. A measure of the overall heating or cooling requirement of a season is likely to be a better indicator of how temperature is affecting consumption. The measures used in this case were heating degree days (HDD) and cooling degree days (CDD).

The number of HDD in a given year is calculated here as the sum of the difference between a threshold temperature, and the average temperature on each day, given that the maximum is below the threshold. In this analysis we define the threshold temperature at 18 degrees Celsius. Any given day makes a contribution to the total number of heating degree days only if the average temperature on that day is below 18 degrees. For example, if the average temperature today is 10 degrees Celsius, then the number of heating degree days contributed to the annual total from that day is 8 (i.e. 18-8). If the average temperature exceeds 18 on a given day then that day contributes zero to the total number of heating degree days for the year. The higher the number of HDD for a given year, the colder that year is.

The concept is the similar for CDD, but the formula takes the sum of degrees that exceed a benchmark (in our case 18 degrees Celsius) for each day. CDD is therefore an indication of how hot a given year is, with a higher number of CDD reflecting a hotter season.

Figure 25 shows the number of CDD for each year from 1980 to 2013 as measured at the Bundoora weather station. The chart demonstrates a slight upward trend over this period, reflecting hotter summer conditions in recent years.

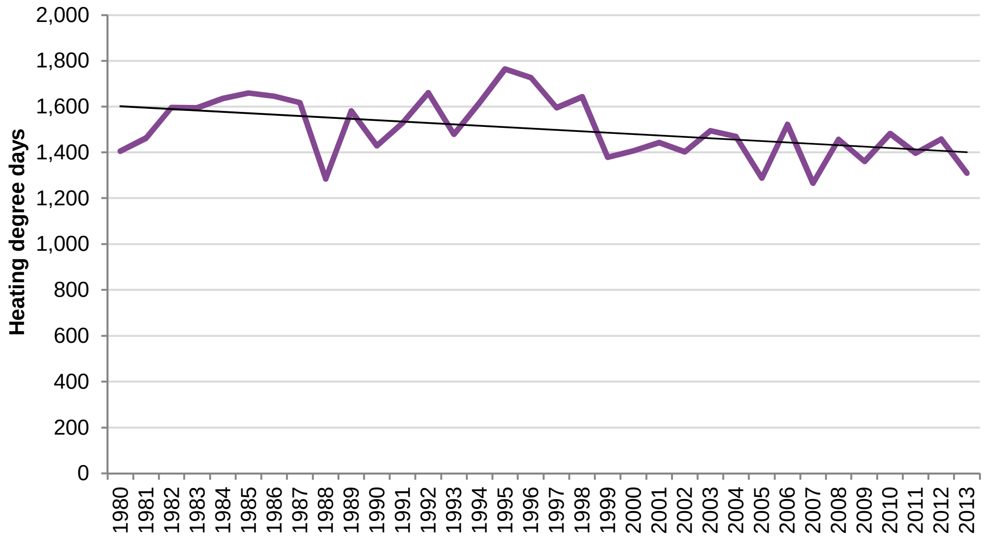
Figure 25 **CDD, Bundoora weather station, 1980 to 2013**



Source: Bureau of Meteorology and ACIL Allen Consulting

Figure 26 shows plots the number of HDD for the same period and weather station. In this case the chart shows a declining trend which reflects milder winters in more recent years.

Figure 26 **HDD, Bundoora weather station, 1980 to 2013**



Source: Bureau of Meteorology and ACIL Allen Consulting

Weather projections

In the forecast period, an assumption must be made as to what are "normal" weather conditions. In particular, as an assumption must be made as to whether temperatures in future will be the same, or warmer, than in the past.

One approach to determining "normal" weather is to take the median weather conditions from a time series. The median of a series is a constant number (for a given series) so using it as a projection of normal weather conditions assumes that these are stationary. In other words, it amounts to an assumption that, over time the median weather conditions (EDD in this case) will not change.

However, in the past it has been accepted by regulators that assuming that the historical median weather will be repeated (on average) is inappropriate. This argument was accepted by the AER when it made its final determination for the current gas access arrangement in Victoria. It was accepted by the Essential Services Commission in its final decision in relation to the previous access arrangement period as well.

Analysis conducted by CSIRO supports this argument. That analysis shows that historical weather data for Victoria exhibits a warming trend (and a corresponding upward trend in the number of EDDs[5]) over approximately the last 60 years. According to the CSIRO this historical trend has been largely due to the Urban Heat Island effect.[6]

Previous analysis by AEMO has reached the same general conclusion, namely that HDD have displayed a trend in the past and that they are likely to continue in line with this trend in future.

Consistent with the CSIRO's analysis, the trend lines shown in Figure 25 and Figure 26 were used to extrapolate CDD and HDD into the forecast period. These values are used as inputs into the base models to generate the forecasts.

4.4 Electricity prices

Another likely driver of consumption is the price of electricity.

Figure 27 and Figure 28 show time series for electricity prices for the residential and small business tariff classes. They cover the period from 1995 to 2013.

Tariffs were relatively stable until 2007 for both tariff classes, before commencing a more rapid ascent. It is reasonable to expect that the strong price rises of recent years have had a dampening effect on consumption across the main customer classes.

The degree of responsiveness of consumption to changes in price is known as the price elasticity of demand. The degree of responsiveness is thought to differ considerably across customer classes, with residential customers thought to be generally less responsive to price changes compared to commercial and industrial users. This is because energy costs comprise a significantly larger proportion of the total expenditures of large customers, so that significant price increases might be expected to lead to adaptive behaviour designed to reduce consumption and hence costs.

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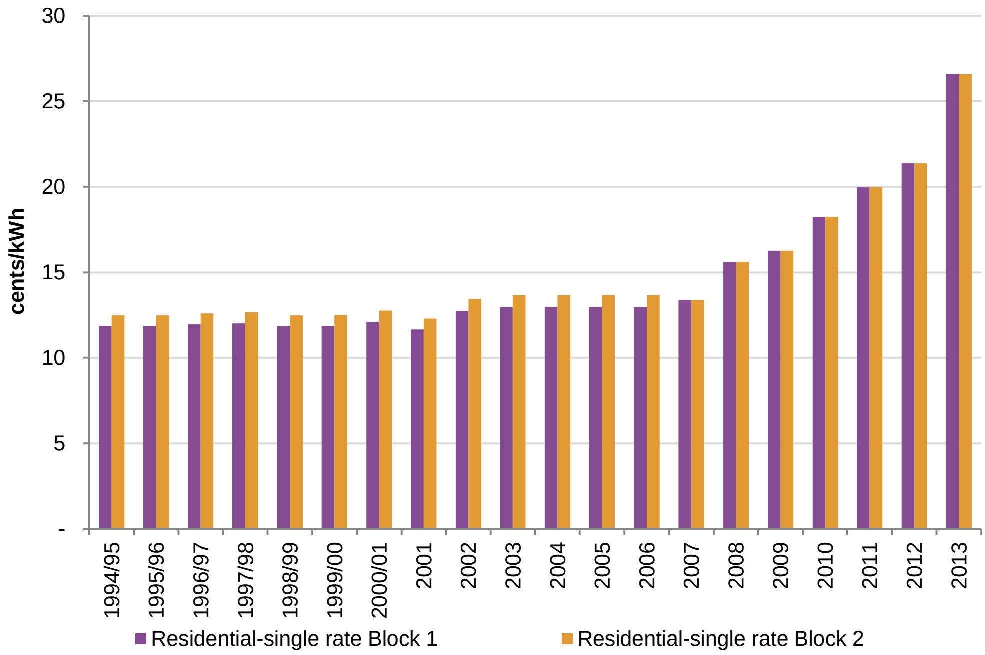
5 CSIRO's analysis was of effective degree days, which take account of wind speed but are similar to HDD. The conclusion that the series is rising over time holds equally well for HDD.

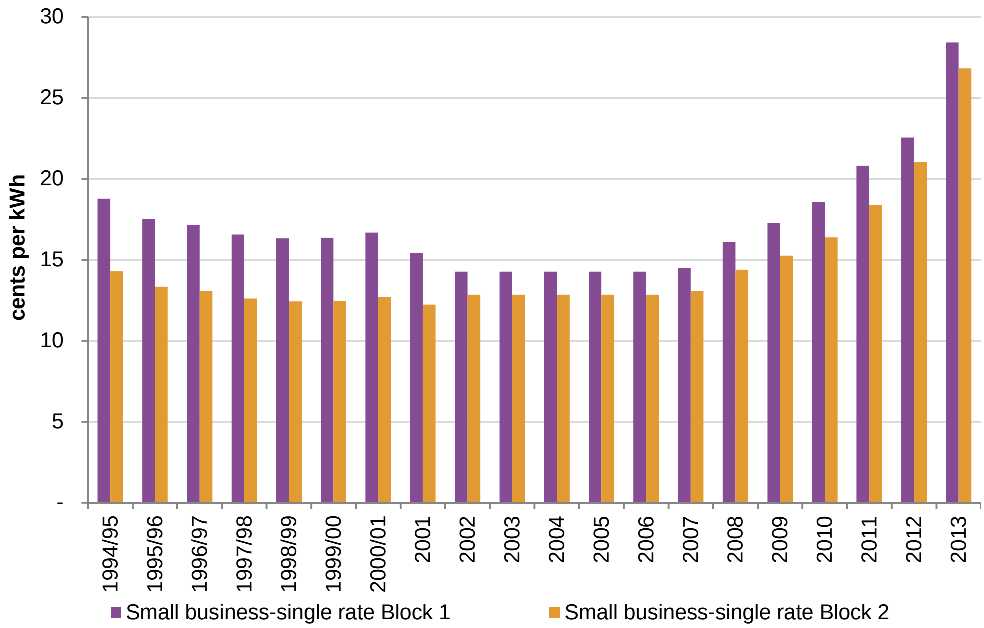
6 In simple terms this effect is the result of increased 'urbanisation' and thus increased numbers of buildings and other man-made structures in urban areas. Those structures absorb heat during the day, then radiate this heat later in the day or that night, thus preventing minimum temperatures from being as low as they may otherwise have been.

Figure 27 **Residential single rate tariff- Block 1 and 2**



Data source: Essential Services Commission

Figure 28 **Small business single rate tariff- Block 1 and 2**



Data source: Essential Services Commission

Forecast electricity price changes

Forecasts of real electricity prices are an input into the forecasting models. To forecast prices, ACIL Allen broke price into three components:

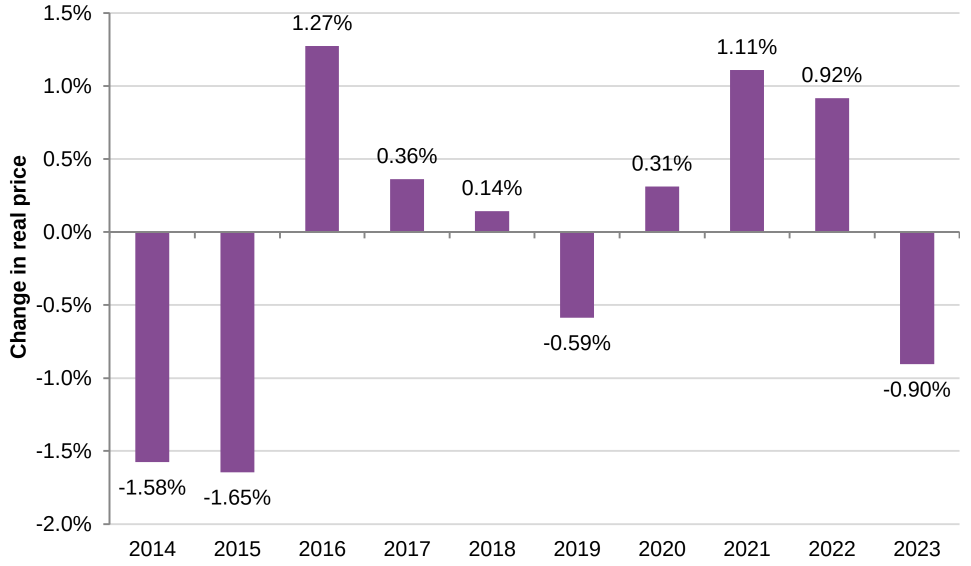
— network use of system (NUOS) charges: a nominal increase of 6.5 per cent in NUOS was assumed in 2015, based on JEN's expectations. ACIL Allen assumed that NUOS charges would remain steady in real terms for the remainder of the forecast period

— wholesale electricity costs: which were projected using ACIL Allen's proprietary Powermark model

— other costs: these include the retail margin, and other costs applied to electricity sales. A neutral assumption of zero real growth was applied into the forecast period.

The final annual price change series (in real growth terms) is shown in Figure 29.

Figure 29 **Forecast change in real electricity prices**



Source: ACIL Allen Consulting

5 Methodology

The consumption forecasts presented in this report were prepared using a set of regression models at the tariff class level. This chapter describes the models that were estimated and compares their results to the relevant historical data (i.e. backcasting).

The coefficients of the models in this chapter were then used with the projected values of the variables in chapter 4 produce the baseline forecasts described in this chapter. These were then adjusted as described in chapters 6 and 7.

Separate models were developed for each tariff class and separate forecasts were produced. The rationale for this is that the drivers of energy growth between customer segments are likely to differ as follows:

- consumption in the residential sector is likely to be closely correlated with population growth and household formation
- consumption in the non-residential sector is more likely to be driven by overall economic growth, though relationships may differ between different types of customers (which are in different tariff classes).

With these differences a forecasting methodology that models tariff classes independently of one another is likely to produce a superior set of forecasts than one which does not.

5.1 Residential models

For the residential tariff class, consumption forecasts were derived from two independent components:

1. residential customer numbers
2. consumption per customer.

The outputs of these two components were multiplied together to provide the baseline forecast of consumption at the tariff class level. Shares of this consumption were then applied to get consumption at the tariff level.

5.1.1 Residential customer numbers

Forecasts of residential customer numbers were generated using the inputs discussed in section 4.2. These inputs comprise:

- population growth by LGA
- number of individuals per household
- the proportion of each LGA that falls within JEN's distribution region.

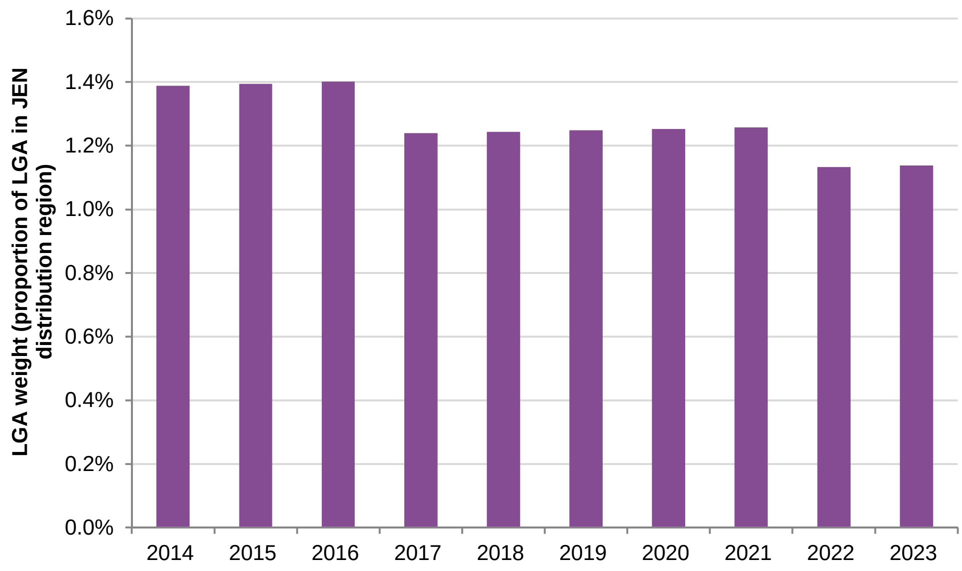
These inputs were used to construct a series of yearly growth rates for the number of households in each LGA in which JEN has customers. The method used to construct these growth rates was as follows.

1. Forecast the population of each LGA: This was done using the LGA specific growth rates obtained from the Department of Planning and Community Development, and shown in Figure 22.

2. Convert population to the number of households: The population forecasts for each LGA were divided by the average number of individuals per household in that LGA.
3. Aggregate the expected number of households that are within JEN's distribution region: This was done using the proportion of area of each LGA within JEN's region as shown in Figure 23. For example, only 12 per cent of households in the Melton LGA were counted towards total JEN households, but 100 per cent of households within the Hume LGA were counted in this figure.
4. Calculate the yearly growth in households within the JEN region: This included only the households in JEN's region calculated within step 3.

Figure 30 shows the growth rates from step 4. Those growth rates were applied to JEN's customer numbers from 2013 onwards to generate estimates of residential customers within JEN's region. Those regional estimates were summed to produce the projection of customer numbers shown in section 2.1.2.

Figure 30 **Projected customer number growth rates for the JEN distribution network**



Source: DPCD Victoria in Future 2012

5.1.2 Residential consumption per customer

Household income is considered to be a key driver of residential consumption per customer. Gross state product is a good proxy for income and is more commonly forecast than income. GSP was included in the model for residential consumption per customer, after being converted to a calendar year basis.

The potential impact of weather is measured by the CDD and HDD and the potential impact of rising prices is captured by the real price of electricity.

The consumption per residential household in this model is actually latent consumption (i.e. metered consumption, plus PV output consumed on site, and with tariff reassignments reversed). This model is represented by equation (1).

$$\begin{aligned} ln(consumption\ per\ customer) = \alpha + \beta_1 \times ln(GSP)_t + \beta_2 \times ln(CDD)_t \\ + \beta_3 \times ln(HDD)_t + \beta_4 \times ln(Real\ price)_t + \varepsilon_t \end{aligned} \tag{1}$$

The coefficients (β_i) in these models can be interpreted as elasticities. That is, they show the percentage change in the dependent variable (e.g. consumption) that would result from a one per cent change in an independent variable (e.g. price).

The estimated coefficients of the residential consumption per customer model are shown Table 15. The coefficient on price is a key parameter. It shows that the price elasticity of demand was estimated to be -0.105. That is, for every one per cent increase in the projected retail price of electricity projected consumption is forecast to decline by 0.105 per cent.

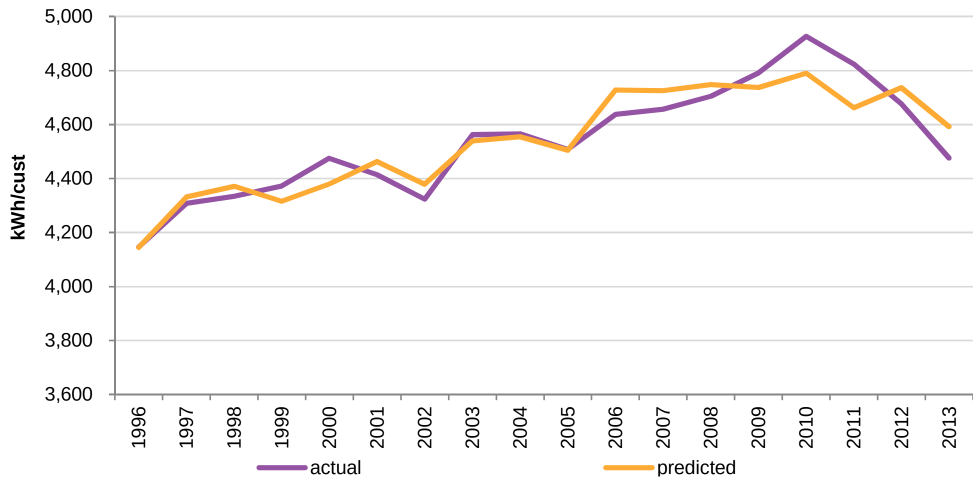
Table 15 **Residential consumption per customer regression results**

Variable	Coefficient	Std. Error	t-Statistic	Prob.
Constant	3.585	0.906	3.959	0.002
$\ln(GSP)_t$	0.263	0.039	6.695	0.000
$\ln(CDD)_t$	0.060	0.026	2.293	0.039
$\ln(HDD)_t$	0.206	0.080	2.576	0.023
$\ln(\text{Real price})_t$	-0.105	0.040	-2.624	0.021
R-squared	0.866			

Source: ACIL Allen Consulting

Figure 31 below plots the actual historical residential consumption per customer numbers against the predicted values. As with the residential customer numbers model the consumption model matches the historical values well. Table 15 shows that the R^2 value is 0.866, meaning 86.6 per cent of the variation in usage per customer is explained by the variation in the regressors.

Figure 31 **Residential usage per customer, predicted versus actual**



Source: ACIL Allen Consulting

Given these components, total consumption was calculated as shown in equation (2).

$$Residential\ consumption = consumption\ per\ customer \times res\ customers \quad (2)$$

The results are in section 2.1.1.

5.2 Non-residential models

Non-residential customers include those in the following tariff classes:

— small business

- large business – LV
- large business – HV
- Sub-transmission

These were forecast independently as described below

5.2.1 Small business models

For the small business tariff class, consumption forecasts were derived from two independent components:

1. customer number growth
2. consumption per customer.

The outputs of the two component models were multiplied together to provide the baseline forecast of consumption at the tariff class level.

The model used for forecasting the number of small business customers was as shown in equation (3).

$$ln(Small\ business\ customers)_t = \alpha + \beta_1 \times ln(GSP)_t + \varepsilon_t \qquad (3)$$

As equation (3) shows, the natural logarithm of the number of small business customers was modelled as a function of a constant and the natural logarithm of GSP. Separate yearly indicator variables are included in the model for the years 2004, 2005 and 2006. This was done to remove the impact of some discontinuities (due to errors) in the customer number data in these years as discussed in section 3.2.

The estimated coefficients for the model of the number of small business customers are presented in Table 16. The key result is the coefficient on GSP, which shows that for every one per cent increase in GSP the projected number of small business customers will increase by 0.38 per cent.

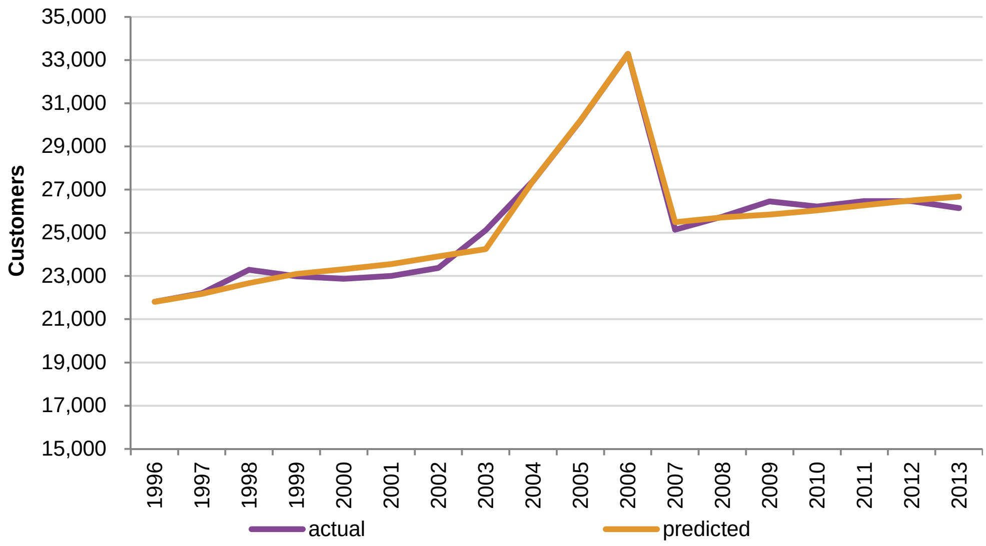
Table 16 **Small business customers regression results**

Variable	Coefficient	Std. Error	t-Statistic	Prob.
Constant	5.338	0.353	15.112	0.000
$ln(GSP)_t$	0.381	0.028	13.494	0.000
2004 $dummy_t$	0.108	0.020	5.493	0.000
2005 $dummy_t$	0.194	0.020	9.811	0.000
2006 $dummy_t$	0.280	0.020	14.130	0.000
R-squared	0.977			

Source: ACIL Allen Consulting

Figure 32 plots the actual historical small business customer numbers against the predicted (backcast) values. It shows that the historical actual number of residential customer numbers is well approximated by the model. This is consistent with the model parameters in Table 16, in particular the R^2 value, which shows that 98.1 per cent of the variation in customer numbers is explained by the GSP and the year dummies.

Figure 32 **Small business customer numbers, predicted versus actual**



Source: ACIL Allen Consulting

Small business consumption was modelled on a per customer basis as a function of GSP and the lagged real price of electricity as shown in equation (4).[7]

$$\ln\ consumption\ per\ customer_{\ t} = \alpha + \beta_1 \times \log\ GSP_{\ t} + \beta_2 \times log(Real\ price)_t + \varepsilon_t \tag{4}$$

The estimated coefficients for the model of small business consumption per customer are presented in Table 17. A key result is the coefficient on real price, which suggests that, for every on per cent increase in price, consumption per small business customer is forecast to decrease by 0.2 per cent. This suggests that small business customers are more price responsive than residential customers, which is consistent with theoretical expectations.

Table 17 **Small business consumption per customer regression results**

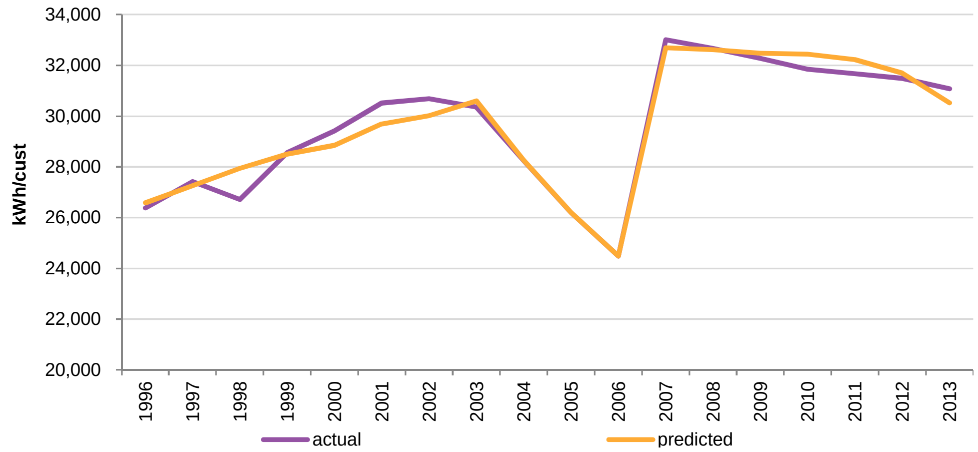
Variable	Coefficient	Std. Error	t-Statistic	Prob.
Constant	6.219	0.381	16.311	0.000
GSP_t	0.374	0.030	12.381	0.000
Small Business price $(real)_t$	-0.200	0.040	-5.044	0.000
2004 $dummy_t$	-0.098	0.022	-4.576	0.001
2005 $dummy_t$	-0.189	0.022	-8.666	0.000
2006 $dummy_t$	-0.275	0.022	-12.296	0.000
R-squared	0.963			

Source: ACIL Allen Consulting

[7] Indicator variables for 2004, 2005 and 2006 are also included in both the customer number and consumption per customer components, but are not shown here.

Figure 33 plots the actual historical small business consumption per customer against the predicted values. It shows that the historical actual number of residential customer numbers is well approximated by the model. This is consistent with the model parameters in Table 17, in particular the R^2 value, which shows that 96.3 per cent of the variation in customer numbers is explained by the GSP, price and the year dummies.

Figure 33 **Small business usage per customer, predicted versus actual**



Source: ACIL Allen Consulting

Total small business consumption was calculated as shown in equation (5).

$$Consumption = consumption\ per\ customer \times small\ business\ customers \qquad (5)$$

The results are in section 2.2.1.

5.2.2 Large business LV

Large LV consumption was modelled on an aggregate basis as a function of GSP and population. That is, unlike the residential and small business tariff classes, the model of Large LV customer numbers is independent of the model of large LV consumption. The model for large LV customer consumption is shown in equation (6).

$$ln(Consumption)_t = \alpha + \beta_1 \times log(GSP)_t + \beta_2 \times log(Population)_t + \varepsilon_t \qquad (6)$$

The estimated coefficients for the large business LV consumption model are presented in Table 18.

Table 18 **Large business LV consumption regression results**

Variable	Coefficient	Std. Error	t-Statistic	Prob.
Constant	5.768	2.011	2.869	0.012
GSP_t	0.140	0.113	1.246	0.232
POP_t	0.995	0.248	4.010	0.001
R-squared	0.947			

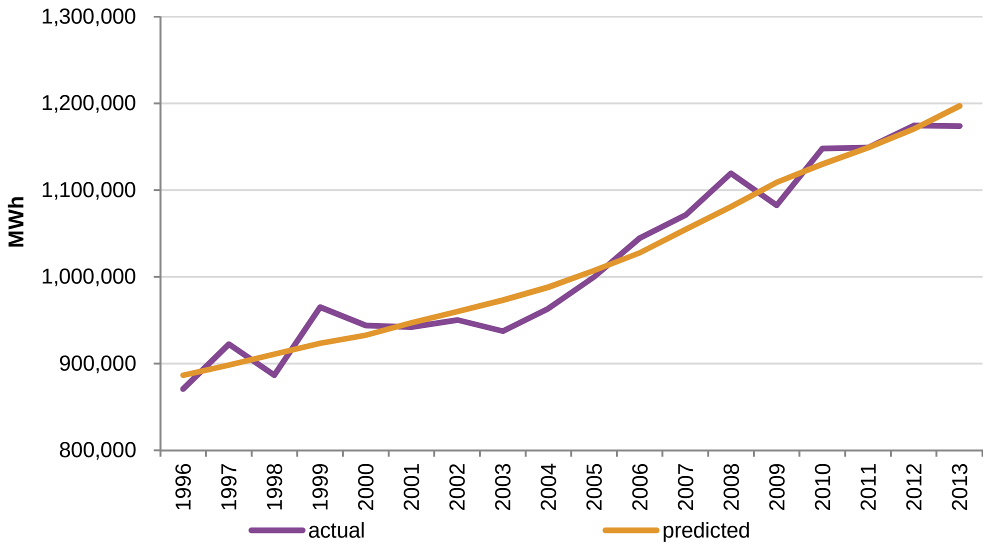
Source: ACIL Allen Consulting

It should be noted that there is a high degree of collinearity between the GSP and population explanatory variables. This means that, while these variables explain most of the variation in consumption when taken together, it is not possible to place a high degree of confidence in the individual estimated coefficients in the model. In other words it is difficult to split apart the impacts of each of the individual explanatory variables reliably.

For the purposes of forecasting this is not problematic as long as there isn't a significant divergence in the relationship between GSP and population in the forecast period relative to the past, which is neither expected nor likely

Figure 34 plots the actual historical large LV consumption against the predicted values. It shows that the historical actual number of residential customer numbers is well approximated by the model. This is consistent with the model parameters in Table 18, in particular the R^2 value, which shows that 94.7 per cent of the variation in large business LV consumption is explained by GSP and population.

Figure 34 **Large business LV consumption, predicted versus actual**



Source: ACIL Allen Consulting

Large LV customer numbers were modelled as a function of a constant and GSP. The model is shown in equation (7).

$$ln(Large\ LV\ customers)_t = \alpha + \beta_1 \times \ln(\mathrm{GSP})_t + \varepsilon_t \quad (7)$$

The estimated coefficients for large LV customer numbers are presented in Table 19.

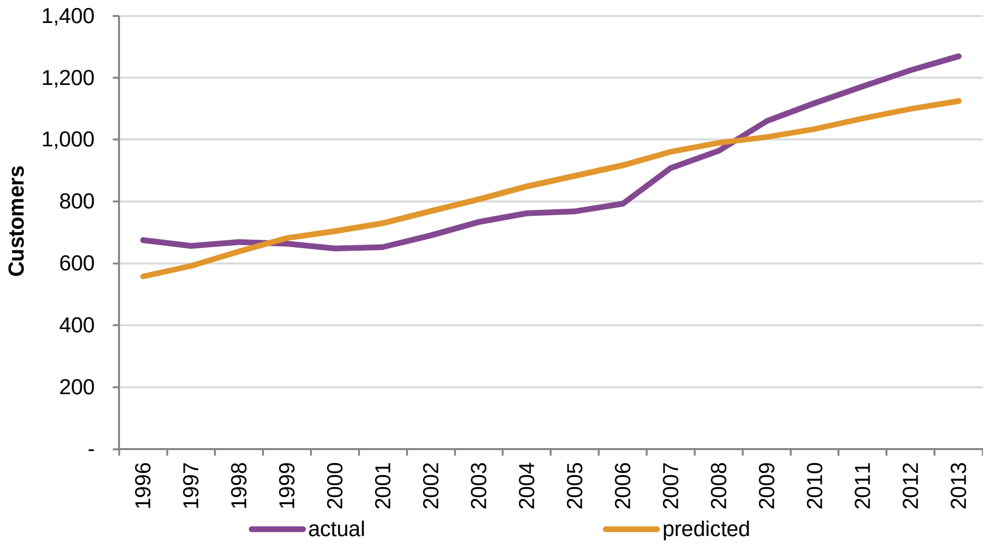
Table 19 **Large Business LV customer numbers regression results**

Variable	Coefficient	Std. Error	t-Statistic	Prob.
Constant	-9.879	1.993	-4.957	0.000
GSP_t	1.328	0.159	8.332	0.000
R-squared	0.813			

Source: ACIL Allen Consulting

Figure 34 plots the actual historical large LV customer numbers against the predicted values. In this case large LV consumption is not as well approximated by the model as was the case in the residential and small business tariff classes. This is reflected in the model parameters in Table 19, which show that this model explains 81 per cent of variation in large business LV consumption. This compares to R^2 values in excess of 95 per cent in many of the previous cases. Nonetheless, the approximation is strong.

Figure 35 **Large business LV customer numbers, predicted versus actual**



Source: ACIL Allen Consulting

5.2.3 Large business HV and subtransmission

Consumption and customer numbers were not modelled separately in the large HV and large ST tariff classes.

In the absence of a time series showing relationships between consumption, customer numbers and their drivers the most recent years' values were used as the starting point for the forecasts. An adjustment is then made for the anticipated closure of the Ford manufacturing plant in October 2016. No other adjustments were made.

5.3 Disaggregating forecasts to tariffs

The models described above operate at the tariff class level. They were disaggregated to individual tariffs by applying time trends to each tariff's share of the total value (customer numbers or consumption) in its tariff class.

Trends in these proportions were extrapolated into the forecast period in all cases. In some cases this suggested that there would be growth in the number of customers on a tariff which had been closed to new customers. In these cases the shares were changed to reflect the fact that new customers would be assigned to a different tariff. In this situation the new customers were assigned to the largest tariff in the tariff class.

5.4 Approach to forecasting contract demand

Contract demand was forecast for each tariff code by applying the percentage share of contract demand to total energy in 2013 for each tariff code, to the total energy forecast in each year. In this way the contract demand increases in line with growth in consumption across all the tariffs.

However, a one-off proportional adjustment is made to account for a demand reset in 2016 to account for JEN's planned tariff reassignment. The adjustment applied is shown below in Table 20.

Table 20 **Impact of demand reset in 2016**

Network Tariff	Demand (currently billed) (kW)	Demand (based on demand reset) (kW)	Adjustment (%)
A230	41,312	39,492	-4.40%
A270	13,775	12,673	-8.00%
A300	149,771	140,979	-5.87%
A30E	10,591	10,455	-1.28%
A320	171,573	162,835	-5.09%
A32E	11,942	11,484	-3.84%
A340	63,549	60,857	-4.24%
A34M	10,943	10,434	-4.65%
A34E	9,739	9,576	-1.67%
A370	22,279	18,677	-16.17%
A37M	31,598	27,847	-11.87%
A400	157,398	151,283	-3.89%
A40E	4,442	4,442	0.00%
A40R	22,488	22,238	-1.11%
A480	24,532	24,400	-0.54%
A500	23,122	23,122	0.00%
A50A	27,800	27,800	0.00%
A50E	15,000	15,000	0.00%

Source: JEN

6 Solar PV and battery storage

This section provides projections of the take up and impact of solar PV systems, both with and without battery storage systems, on electricity use in JEN's region. It provides an uptake projection, comprising:

1. the number of installations
2. the capacity of installations (per unit)
3. the total installed capacity.

It draws on that projection to estimate:

1. the impact on demand
2. the impact on consumption.

6.1 Model overview

The solar PV uptake projection is based on ACIL Allen's analysis of historical installation rates and its estimate of the financial return to solar PV system owners. Econometric techniques, in particular linear regression, were used to confirm and quantify that relationship from historical data and to project uptake into the future.

The analysis was conducted for the entire JEN region. Residential and non-residential customers were analysed together.

The possibility that customers might have a propensity to 'rush in' to install solar PV systems in advance of reductions in policy support was taken into account using a dichotomous (dummy) variable. This approach does not 'force' this propensity into the model, but allows it to be taken into account if it is present.

No other time series structure was adopted within the model. That is, it was assumed that the installation rate in any given quarter depends on the payback that would be earned from installing a system in that quarter and the 'rush-in' effect, but nothing else.

The regression model for uptake of solar PV is summarised in equation (8):

$$\begin{aligned} \ln Capacity_t \;&=\; 7.315 + \; 0.0004 * Payback_t \\ &+ 0.289 * Rush - in_t + \; 1.274 * Rush - in2_t + \; \varepsilon_t \end{aligned} \tag{8}$$

where:

$Capacity_t$	is the quantity of solar PV systems installed each quarter, measured in kW
$Payback_t$	is ACIL Allen's estimate of the net financial return per kW (in net present value terms) a typical customer would achieve by installing a solar PV system each quarter, measured in 2014-15 \$/kW installed
$Rush\text{-}in_t$	is a dichotomous variable accounting for changes in policy support. It was set to 1 when a policy change that would reduce support for solar PV was imminent in 2011, and 0 otherwise

Rush-in2_t is a second dichotomous variable accounting for changes in policy support. It was set to 1 when a policy change that would reduce support for solar PV was imminent in 2012, and 0 otherwise

ε_t is a random error term with an expected value of zero

t is a time index for each quarter from 1 July 2009 until 30 September 2013

The regression statistics for this regression model are set out in Table 21. They indicate that the explanatory power of the model and of each explanatory variable individually is moderately high. For example, 85.2 per cent of the variation in log-capacity is explained by the payback and rush-in variables.

Table 21 **Residential solar PV uptake model - regression statistics**

	Coefficient	Standard error	t-stat	p-value
Constant	7.315	0.089	82.190	0.000
Payback	0.000	0.000	6.050	0.000
Rush-in	0.289	0.225	1.286	0.218
Rush-in 2	1.274	0.244	5.225	0.000
Overall statistics				
R^2	0.851			

Source: ACIL Allen Consulting

To produce an estimate of installed capacity the model must be transformed from its logarithmic form as follows:

$$Capacity_t = \exp(7.315 + 0.0004 * Payback_t + 0.289 * rus\square - in_t + 1.274 * rus\square - in2_t + \varepsilon_t) \quad (9)$$

Therefore:

$$Capacity_t = 1503.04 * \exp(0.0004 * Payback_t) * \exp(0.289 * rus\square - in_t) * \exp(1.274 * rus\square - in2_t) * \exp(\varepsilon_t) \quad (10)$$

where the variables are as described above.

Projections of solar PV uptake by residential customers were produced by applying equation (10) to projections of estimated payback to installing a solar PV system. Historical data were obtained from 2009, when solar PV systems began to appear in JEN's region in substantial number, until early 2014. Projections are presented here for the period from 2014 to 2021.

The remainder of this chapter provides a detailed description of the data inputs upon which the projection was based and then the results of the projection.

Section 6.2 provides a description of the dependent variable used in the analysis.

There are three independent variables, namely 'payback', 'rush-in', and 'rush-in2'. The 'payback' variable is the result of detailed analysis and modelling by ACIL Allen, and is based on a number of inputs. Section 6.3 describes the way this variable was constructed, as well as the inputs to that process.

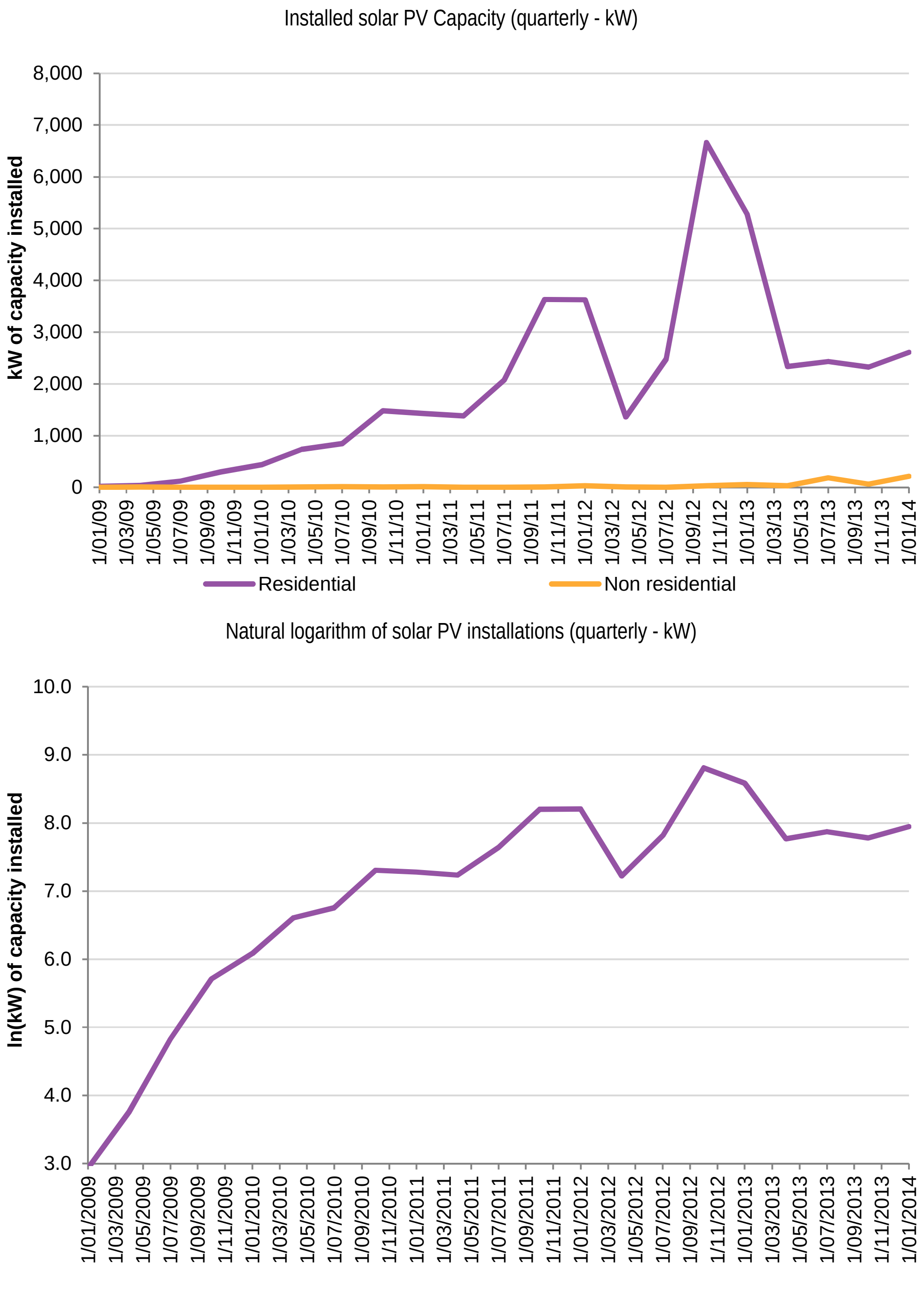
Section 6.4 provides a brief description of the 'rush-in' and rush-in2' independent variables.

6.2 Dependent variables – installed capacity

The dependent variables in the solar PV uptake models were the capacity of solar PV systems installed each quarter in JEN's region.

The variables were compiled by ACIL Allen from data supplied by JEN showing the capacity and installation date of each solar PV system installed in JEN's region. The data are summarised in Figure 36, which shows the level of capacity as well as its natural logarithm.

Figure 36 **Solar PV installations in JEN's region**



Source: ACIL Allen Consulting

Figure 36 shows that the vast majority of solar PV capacity currently installed in JEN's region is 'residential'. Although there has been some non-residential capacity installed in the region in 2013, the lack of substantial sample size for non-residential systems led to these systems being included in a single equation for solar PV capacity, rather than assessment of non-residential solar PV separate from residential. For the purposes of forecasting, all solar PV capacity is assumed to be residential.

6.3 Independent variable - payback

The payback variable is the difference, in net present value terms, between the benefit a customer can expect to accrue from their solar PV system and the cost of installing it. Therefore, the payback is the (net present) value of:

3. the payment received for electricity generated and exported to the grid
4. plus the value (avoided cost) of electricity generated and used on site
5. plus the value of any upfront payments received
6. less the upfront cost of installing the system.

Items 1 and 2 are paid over the life of the system. The analysis is based on the net present value of those two streams of payment. The other two items are upfront, so don't need to be discounted.

Formally, payback is as shown in equation (11)

$$\begin{aligned} Payback_{ct} = {} & upfront\,payment_{ct} - installation\,cost_{ct} \\ & + avoided\,retail_{ct} + export\,revenue_{ct} \end{aligned} \tag{11}$$

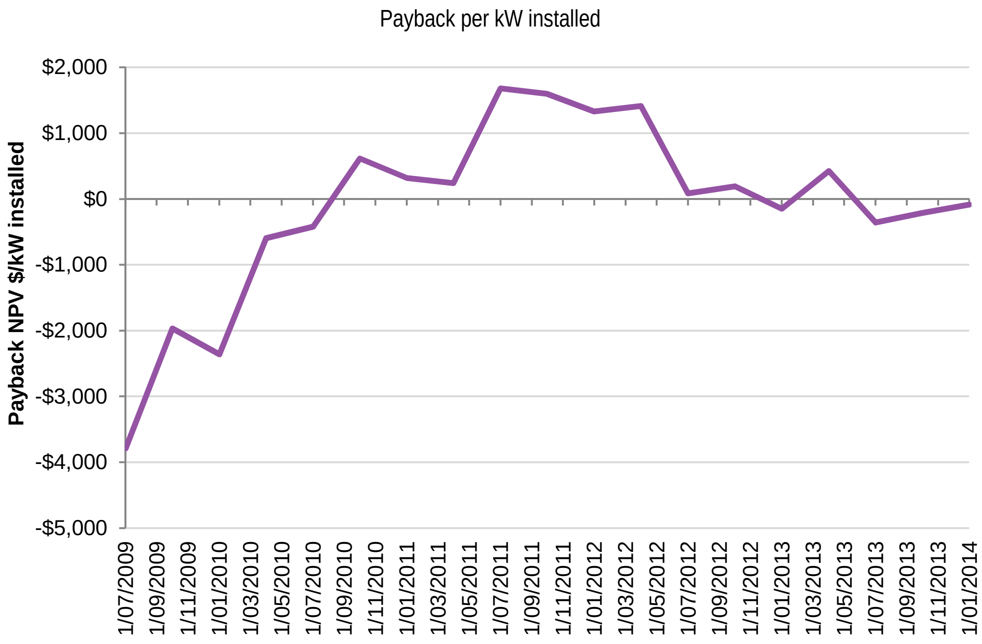
Where:

upfront $payment_{ct}$	is the value of any upfront payments to a customer for a solar PV system of size c installed in quarter t
installation $cost_{ct}$	is the cost, in JEN's region, of installing a solar PV system of capacity c in quarter t
avoided $retail_{ct}$	is the value (opportunity cost) of electricity that a customer who installs a system of size c expects to avoid buying by using electricity generated by their solar PV system
export $revenue_{ct}$	is the value of the payments to the customer for electricity generated and exported to the grid by a solar PV system of size c installed in quarter t
c	is capacity of the solar PV system, either 1.5, 2, 3, 4 or 5 kW (or 66kW in the non-residential model)
t	is a quarterly time index beginning in quarter 1 2009

A description of the way each variable was constructed and projected is provided in the sections that follow.

The resulting estimate of payback on a solar PV system is shown in Figure 37, normalised to show payback per kW installed.

Figure 37 **Solar PV paybacks per kW installed – 2009 to 2013, JEN region**



Source: ACIL Allen Consulting

6.3.1 Upfront payments

Three sources of upfront payments for solar PV installations were taken into account. Two applied during the historical period and one is expected to apply during the projection. They are:

1. the former Solar Homes and Communities Program (SHCP), which provided an upfront cash rebate
2. the indirect subsidy provided by the creation of 'Small-scale Technology Certificates' (STCs)[8] under the Small-scale Renewable Energy Scheme (SRES), including the creation of additional STCs through the 'Solar Credits multiplier'

Under SHCP, customers who installed solar PV systems received an upfront rebate of $8,000. SHCP was in place from the beginning of the historical data until the second half of 2009.

In addition to the upfront payment through SHCP solar PV systems are eligible to create certificates for the renewable electricity they generate. This was the case in the historical period and is assumed to continue into the projection period.

The details, and names, of the policies that underpinned those certificates have changed over time, as has the name of the certificates. However, the underlying concept has remained the same. solar PV systems have always been deemed to generate a certain amount of electricity over their lifetime and, therefore, have always been able to create a certain number of certificates. There has always been a market for those certificates and by selling those certificates the owner of the solar PV system has always been able to 'extract' value from their solar PV system. In practice, certificates have usually been assigned to the supplier of the solar PV system, making them equivalent to an upfront payment.

[8] STCs were formerly known as 'Renewable Energy Certificates', or RECs, and are still widely referred to this way.

The value of this upfront payment has always depended on system size and certificate price. From 1 July 2009 until 31 December 2012, it also depended on the 'solar credit multiplier'. While the multiplier was greater than one, eligible customers who installed solar PV systems were deemed to create more than one certificate for each MWh of electricity their system was deemed to generate. The multiplier was originally 5, meaning that a solar PV system would create 5 solar credits for every MWh of electricity it was deemed to generate, for the first 1.5 kW of capacity installed. The multiplier then declined over time.

The SHCP was phased out in favour of the solar credit multiplier in the second half of 2009. Customers could benefit from either the SHCP or the STC multiplier, but not both.[9]

To address the overlap between these two policies, 50 per cent of solar PV installations in quarter 3 2009, and 20 per cent in quarter 4 2009 were assumed to receive the SHCP rebate. The remainder were assumed to use the Solar Credits multiplier to generate extra STCs (then RECs).

The solar multiplier and certificate values factored into the analysis are shown in Table 22. In effect, a solar PV system installed in 2009 was assumed to receive part of the SHCP grant and part of its entitlement to solar credits, which is an average summary of the reality that some systems received one, while others received the other.

Table 22 **Solar Credits multiplier**

	Until July 2009	Q3 2009	Q4 2009	Q1 2010 – Q2 2011	Q3 2011 – Q2 2012	Q3 & Q4 2012	From January 2013
Solar Credits multiplier	1	3.0	4.2	5	3	2	1
SHCP value	$8,000	$4,000	$1,600	$0	$0	$0	$0

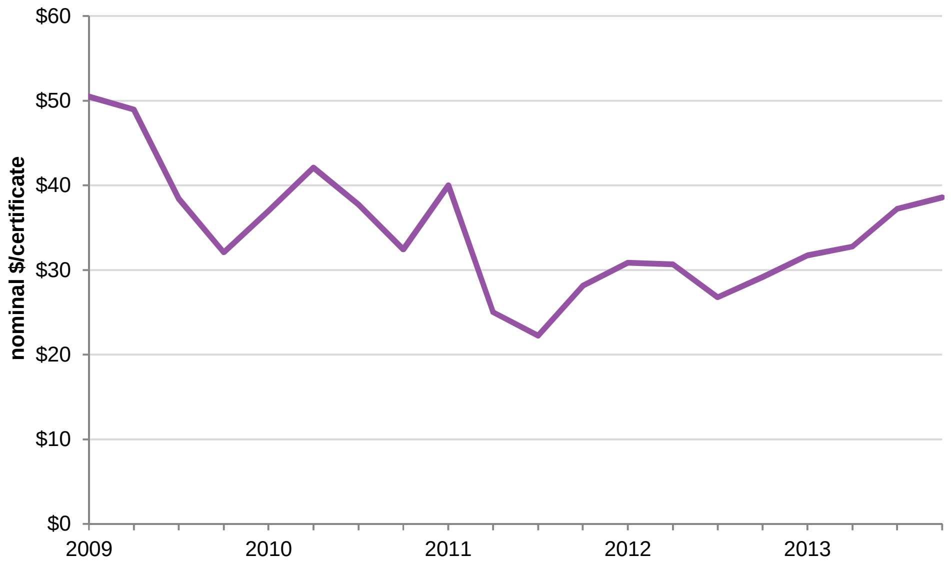
Note: Q3 2009 and Q4 2009 multipliers are 'implicit' multipliers based on relative uptake of Solar Credits and the SHCP rebate. Years and quarters are shown on a calendar year basis.
Source: ACIL Allen Consulting; *Renewable Energy (Electricity) Regulations 2001*

Unlike the SHCP payment, the value of certificates varied over time independently of the multiplier. The assumed values from 2009 to the present are shown in Figure 38.[10] Beyond 2013 the certificate price and multiplier were assumed to remain constant (in nominal terms), at $39 per certificate, which is just below the legislated maximum.

[9] Customers who received the SHCP rebate received the value of certificates as if the multiplier was 1.

[10] Note that until 2011 solar PV installations were deemed to create Renewable Energy Certificates, which could then be sold to electricity retailers at a price determined in the market. Beginning in January 2011, small solar PV installations were no longer eligible for RECs and began to be eligible for a rebate based on the price of a Small Technology Certificate instead. This price is legislated to be $40 but can fall well below this level in wholesale trade. From a modelling perspective the difference in the two certificates is immaterial other than through the difference in value.

Figure 38 **REC/STC prices (nominal $/certificate)**



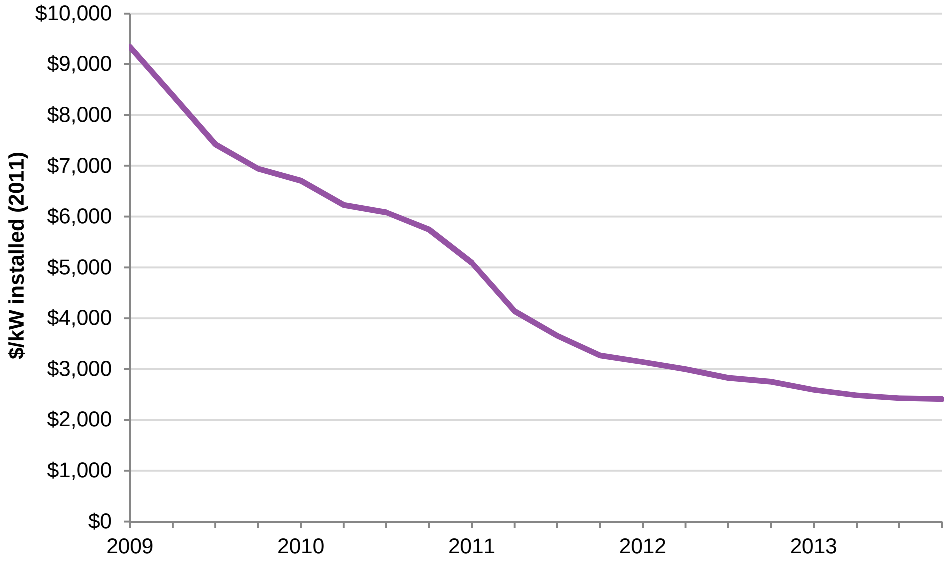
Note: REC prices prior to Q1 2011, STC prices subsequently.
Source: AFMA; ACIL Allen Consulting

6.3.2 Installation cost

The cost of installing a solar PV system has varied over time. ACIL Allen's estimates of system cost in JEN's region were derived by taking a national average system cost which was scaled to account for differences in cost due to system size and to account for differences in system costs in Victoria when compared to other parts of the country. No allowance was made for the cost of inverter replacement or for ongoing system maintenance costs.

The national average system cost values are summarised in Figure 39.

Figure 39 **National average historic solar PV installation cost (2011$/kW)**



Note: Cost excludes rebates, subsidies, and GST
Source: AECOM; ACIL Allen Consulting; SolarChoice

ACIL Allen's cost estimates were based on the best available data for each time period. They are described here beginning with the most recent.

October 2012 to December 2013

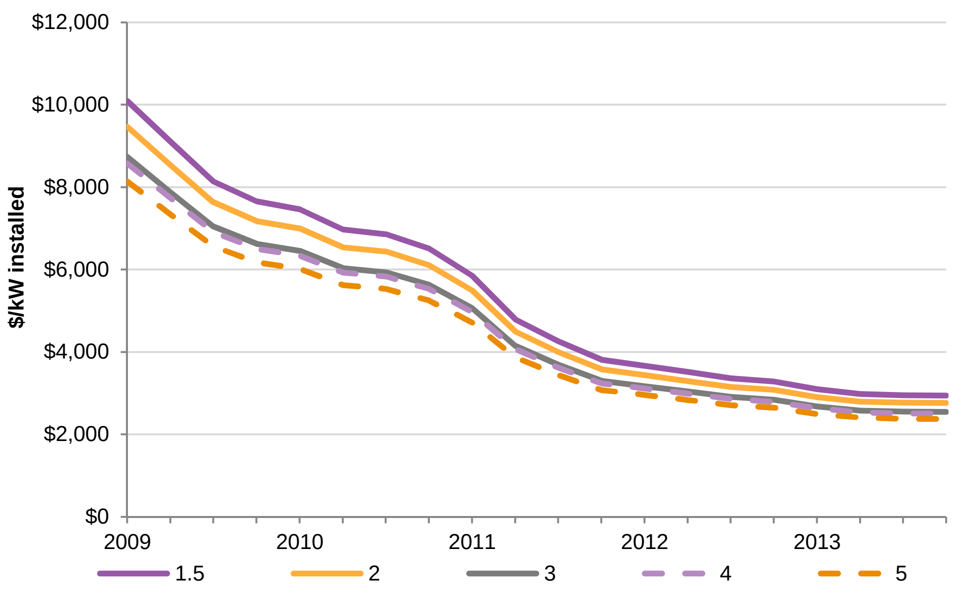
For the period from October 2012 to December 2013 (inclusive) the national average cost of installing a solar PV system in JEN's region was based on SolarChoice's "solar PV Price Check" publication.[11]

That publication sets out prices for systems of different sizes in each state, which were adjusted for GST and Small-scale Technology Certificate (STC) values to estimate an underlying system cost.

While "solar PV Price Check" provides a Victorian system cost estimate, this was not adopted directly as doing so would have ignored information on system costs from other states, and so would be more susceptible to sampling error in the construction of the Victorian price index.

Rather, state-level costs were aggregated into a national average and a cost premium or discount was developed for each state based on averaged variations across the period. Similarly, smaller and larger systems were given a premium or discount based on observed variation from the average. This approach gives 'smoother' solar PV costs curves that will produce less arbitrary variation in solar PV financial returns over time. The cost curves are shown in Figure 40.

Figure 40 **Estimated cost of installing solar PV systems in JEN's region by system size – 2009 to 2013**



Source: ACIL Allen Consulting

This analysis suggested that the cost of installing a solar PV system in Victoria is approximately 3.4 per cent more than the national average.

[11] See www.solarchoice.net.au. These are also published from time to time in sources such as Climate Spectator. See for example, http://www.businessspectator.com.au/article/2013/12/13/solar-energy/solar-solar PV-price-check-%E2%80%93-december

SolarChoice data also indicates that smaller systems are more expensive per kilowatt than larger systems once STC discounts were taken into account. The relative premia/discounts associated with different sized systems relative to the cost of the average Victorian system are set out in Table 23.

Table 23 **Solar PV installation premium/discount by system size**

System size (kW)	1.5	2	3	4	5
Premium/discount	12.1%	5.2%	-3.0%	-4.7%	-9.6%

Note: Positive values refer to a premium, and negative values refer to a discount.
Source: ACIL Allen Consulting analysis of SolarChoice data

Before December 2012

Before December 2012, solar PV Price Check was unavailable, so different data sources were used. The estimated national average cost of installing a solar PV system between January 2009 and September 2012 (inclusive) was based on:

- from 2009 to mid 2010 - AECOM analysis of solar PV system costs for the NSW Government (published October 2010),
- from 2010 to November 2011, ACIL Allen (then ACIL Tasman) reviews of internet quotes for solar PV systems undertaken as part of analysis for the Clean Energy Regulator (late 2010, mid 2011, late 2011)
- between November 2011 and September 2012 the cost was assumed to move in a linear fashion between ACIL Allen's last estimate and the values shown in "solar PV Price Check"[12].

During this period the premia/discounts associated with different system sizes and described in Table 23 were retained.

6.3.3 Avoided retail and export revenue

The avoided retail and export revenue variables relate to the value the owner of a solar PV system obtains from the electricity the system generates. There are two variables because the source, and amount, of value differs. Specifically:

- the value of the electricity that is used on site is the retail price of electricity at the time, because that is what the customer would have paid for that electricity if it had not been generated by the solar PV system
- the value of electricity the customer exports to the grid is the payment they receive for it, which is referred to as the 'export price'. This varies depending on the policy settings when the solar PV system was installed.

It follows from this that the value a solar PV customer obtains from the electricity their solar PV system generates depends on the following four factors, which are discussed in turn below:

3. the system output, or the amount of electricity that the solar PV system generates
4. the export rate, or proportion of that electricity that is exported rather than used 'on site'
5. the retail price of electricity
6. the 'export price'.

[12] This approximation is appropriate due to the modest rate of decline in costs over that period.

System output

System output was estimated in the same way that it is estimated by the Clean Energy Regulator (CER) in the context of the SRES and other schemes before it. The CER deems the annual output of solar PV systems in JEN's region to be 1182 MWh of electricity for each kW installed.[13]

Therefore, the estimated annual system output was as shown in Table 24.

Table 24 **Estimated output of solar PV systems of various sizes in JEN's region**

System size	Estimated output
kW	MWh per annum
1.5	1.78
2	2.37
3	3.56
4	4.74
5	5.93

Source: ACIL Allen Consulting

Export rates

Export rates in JEN's region were estimated based on data relating to a sample of 580 of JEN's residential customers who are not on tariffs with a feed-in component (i.e. are on tariffs A100, A10X, or A10I). These rates were estimated by distributing the solar power generation by half hour block, using solar insolation data collected by the Bureau of Meteorology at Melbourne Airport, and comparing this to the observed consumption of each individual in the sample. Excess generation is assumed to be exported.

The average export rates for customers within the sample are shown in the 'Unmatched demand' column of Table 25. Export rates vary between 50 per cent for the smallest system size, to 77 per cent for the largest residential system size.

However, this is likely to overstate the export rates for many systems, as within the current policy environment, consumers are better off using solar capacity to offset their own usage, rather exporting excess capacity to the grid. Therefore, customers are likely to engage in behaviour that 'matches' their solar PV capacity to their usage levels. In particular, customers are unlikely to install systems that are too large for their consumption levels. A series of assumptions have been made regarding the minimum level of consumption required in order for a customer to install each system size. These assumptions and the corresponding export rates are also shown in Table 25.

[13] This amount was determined by the Clean Energy Regulator (then Renewable Energy Regulator). The value is based on the postcode where the solar PV system is installed, though all of JEN's area, and in fact the vast majority of Victoria, has the same value.

Table 25 **Estimated export rates (per cent of energy generated)**

System size (kW)	Unmatched demand export rates	Minimum consumption level	Matched demand export rates
1.5	50%	1 MWh/Year	49%
2	57%	1.5 MWh/Year	55%
3	67%	2.5 MWh/Year	61%
4	73%	3.5 MWh/Year	65%
5	77%	4.5 MWh/Year	67%

Note: Unmatched demand export rates are rates calculated across all customer demand sizes. Matched demand export rates filters out demand profiles which are considered too low for the customer to consider each respective PV system size.

Source: ACIL Allen Consulting

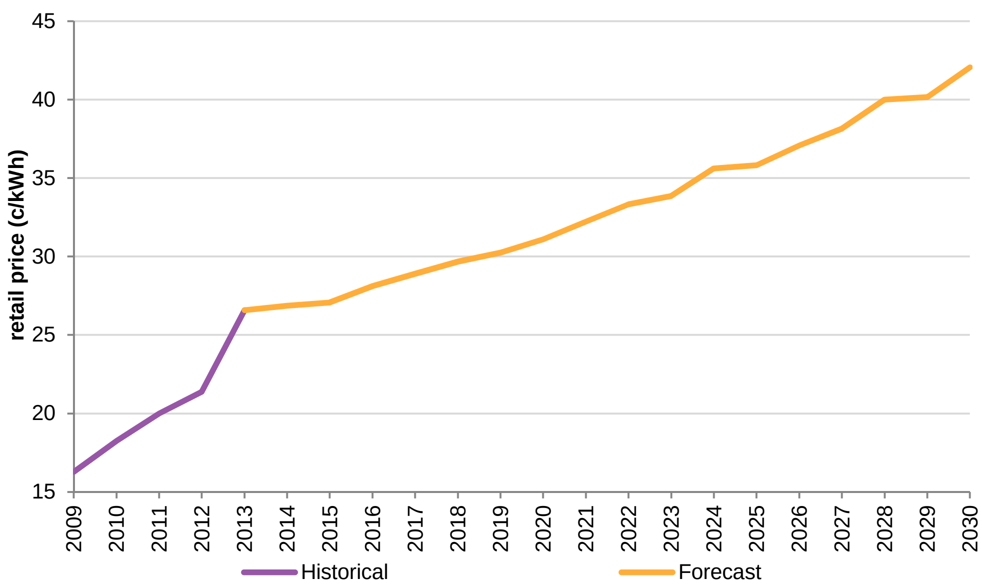
By assuming a minimum consumption level required in order to install each system size, the proportion of energy exported for each storage size is less variable across system sizes. These export rates were used to inform the relative payback for each system size, by assuming that paybacks for all customers that install each system size are identical.

Retail electricity prices

The average retail price of electricity avoided was assumed to be the average standing offer price for JEN's region as published by the Essential Services Commission. Therefore, the value of electricity generated and used 'on site' was assumed to be the standing contract price of electricity at the time.

In the forecast period, retail electricity prices were assumed to grow in line with the method outlined in Section 4.4. Empirical and projected retail electricity prices are shown in Figure 41.

Figure 41 **Electricity retail price series**



Source: ACIL Allen Consulting

Export price

The export price payable to a customer with a solar PV system consists of two parts, each of which has varied over time.

The two parts are:

- premium Feed-in Tariffs (FiTs), which are funded by electricity customers through distribution charges and have been equal to or greater than the retail price of electricity
- buy back rates, which are funded by electricity retailers and are set periodically by the Essential Services Commission to reflect the wholesale price of electricity.

Premium FiTs were in place in Victoria from the beginning of the period analysed until September 2012. The rates were:

- the retail price of electricity until 31 August 2009
- 60 c/kWh from 1 September 2009 until 31 December 2011, payable from the date of installation until 30 June 2024[14]
- 25 c/kWh between 1 January and 30 September 2012, payable from the date of installation until 30 June 2016
- no premium FiT after 1 October 2012.

In addition to these FiTs, which are funded by electricity customers, Victorian electricity retailers also pay a 'buy-back' rate for electricity exported to them by their customers.

The 'buy-back' rate was assumed to be 8.5 c/kWh for 2013, which is slightly higher than the regulated minimum rate of 8 c/kWh.

In the forecast period it was assumed that there will be no premium FiT and that buyback rates would increase in line with retail prices. This is a simplifying assumption that might reasonably be made by a household at the time of installation given that customers will not have full visibility of the trajectory of 'buy-back' rates.

6.4 Independent variables – 'rush-in' and 'rush-in 2'

Between 2009 and 2013 the degree of policy support varied significantly. Most of the time, when policies changed there was advance warning. At these times customers would 'rush in' to install a solar PV system before the change took effect. The tendency for householders to 'rush in' to installing solar PV systems just before supportive policies are removed was taken into account using two indicator variables. The first was set to '1' in the following periods (and '0' in all other periods):

- Quarter 2 2011, reflecting the imminent reduction in the Solar Credits multiplier from 5 to 3 from 30 June 2011
- Quarters 3 and 4 2011, reflecting the imminent closure of the 60 c/kWh FiT scheme (with the final 'rush' of installations continuing through until the end of 2011

The second 'rush in' variable was set to '1', in the following periods (and '0' in all other periods).

- Quarter 3 2012, reflecting a lagged response in installations to the reduction in the Solar Credits multiplier from 3 to 2.

[14] The 60c/kWh FiT ended on 30 September 2011, but customers who had applied for it before that date were still eligible even if their systems were not installed by that date. Therefore, it was assumed that systems installed later in 2011 also received this FiT. This was supported by empirical analysis showing an improved regression fit with this assumption that without it.

— Quarter 4 2012, reflecting a lagged response in installations to the closure of the 25 c/kWh FiT scheme, as well as the imminent reduction in the Solar Credits multiplier from 2 to 1.

Two rush in variables were used in order to reflect differences in the scale of the 'rush-in' effect in each of these sets of policy changes.

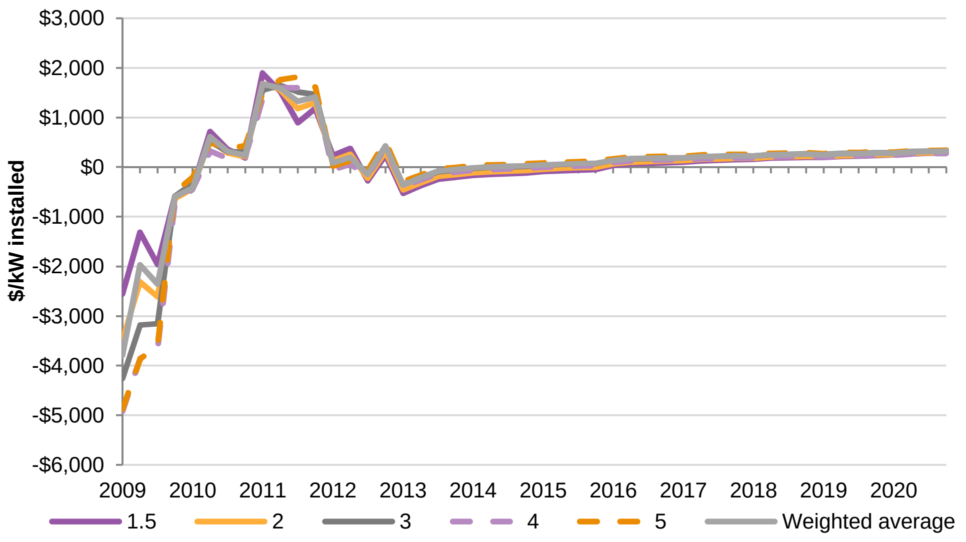
6.5 Results

6.5.1 Payback

The return on solar PV systems of various sizes is shown in Figure 42 (NB in the historical period the weighted average is the same as shown in Figure 37).

Figure 42 shows that, for residential customers, financial returns on solar PV systems were substantially negative until the introduction of FiTs and the dramatic reduction in solar PV capital costs through the period 2009 to 2011. However, despite the removal of FiTs and reduction in other forms of government assistance (primarily the 'Solar Credits' policy), falling system costs and rising electricity prices result in projected positive returns on all sizes of solar PV system.

Figure 42 **Net financial returns per kilowatt (real $2013-14)**



Source: ACIL Allen Consulting

In the forecast period, the projected return is quite flat, and the net present value of returns is around zero for most systems. This is mainly because:

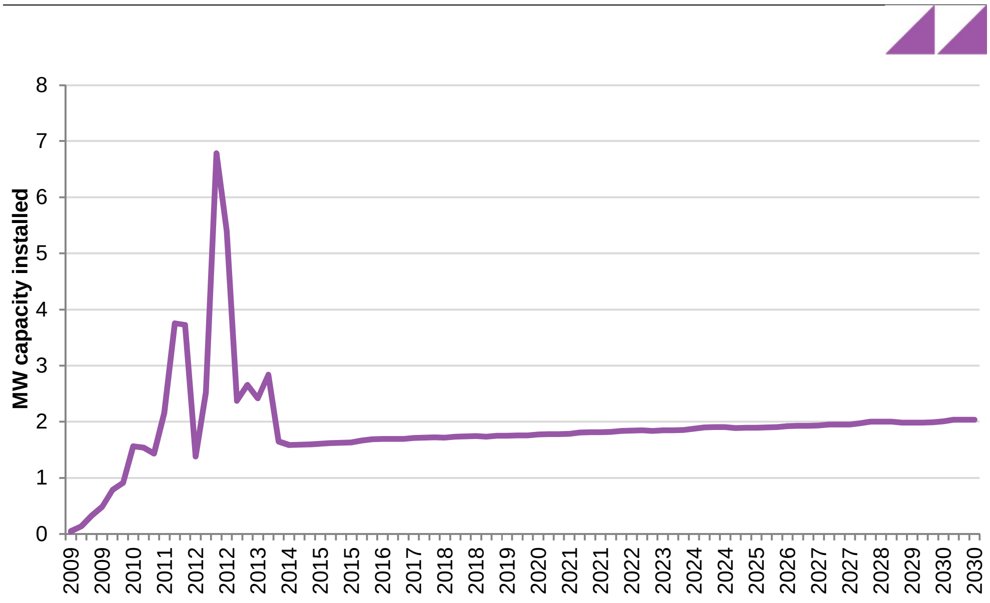
— electricity prices remain relatively stable

— the decrease in system costs broadly offsets the decline in policy support that arises from the declining deeming period under SRES.

The same pattern that is seen in the financial returns is also seen in the installation rates shown in Figure 43, which shows the capacity of solar PV systems installed in JEN's region on a quarterly basis since 2009 and through the projection period.

Consistent with the payback it shows high rate of installation between 2010 and early 2013, when it begins to taper off. The projection is that systems will continue to be installed at approximately 1.7 MW per quarter, which is a strong rate, though not nearly as strong as was observed when policy support was at its strongest and when consumers were 'rushing in' to take advantage of policy support before it was withdrawn. The projection is relatively stable at this level because the financial return to installing systems is forecast to be stable.

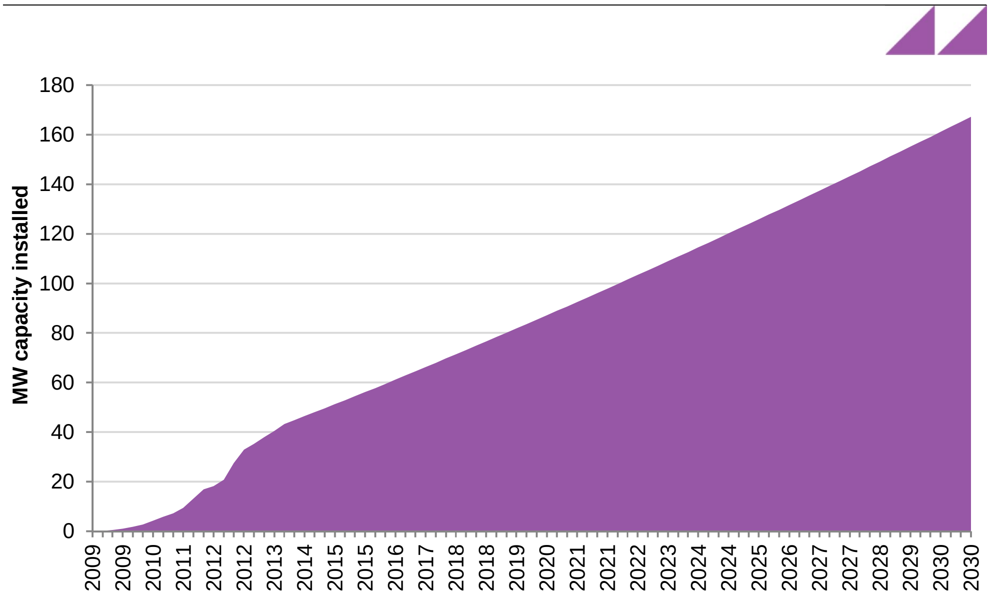
Figure 43 **Quarterly solar PV system installations**



Source: ACIL Allen Consulting

The total projected capacity of solar PV systems, showing residential and commercial systems separately, in JEN's region is shown in Figure 44.

Figure 44 **Cumulative capacity of installed solar PV systems by system type**

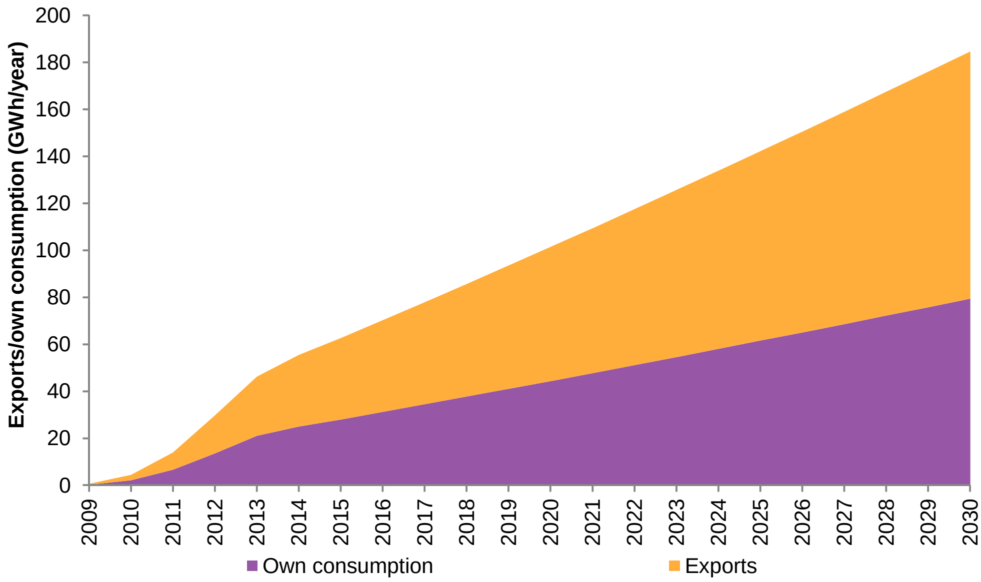


Source: ACIL Allen Consulting

6.5.2 Energy impacts

The impact of solar PV systems on energy forecasts needs to account for both the output of systems and the level of exports from each system. Exported electricity is ultimately consumed by customers other than the owner of the solar PV system, and is therefore levied network charges. Therefore, only 'own consumption' energy affects network volumes and revenues. Noting this, the progressive increase of both electricity exports and own consumption are presented in Figure 45 below.

Figure 45 **Energy exports and own consumption**



Source: ACIL Allen Consulting

6.6 Solar PV systems with storage

The analysis also considers the potential uptake of solar PV systems with battery storage capability. The approach taken was conceptually linked to that used to project solar PV uptake. The main difference is that a battery storage system allows a customer with a solar PV system to reduce their export rate and, therefore, maximise the benefit from avoided retail costs. The other difference is that the installation cost is larger to account for the storage system.

A more detailed description of these changes is provided in sections 6.6.1 and 6.6.2.

The changes were only made during the forecast period. Storage has not been adopted in any meaningful volume by households in Australia. This means that storage systems were not taken into account during the historical period and no adjustment was necessary.

The results of this analysis are in Figure 46, which shows the return on solar PV systems of various sizes with and without storage.[15] It shows that adding battery storage to a solar PV system is expected to reduce the return on the solar PV system throughout the regulatory period. In other words ACIL Allen projects that customers will achieve financially better returns from solar PV systems without storage than with storage during the regulatory period.

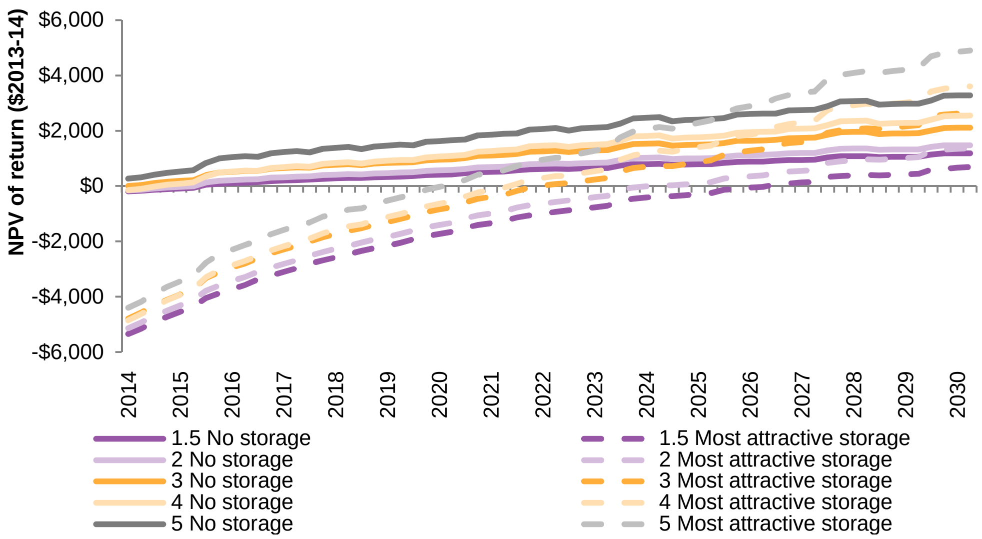
This result holds for all solar PV system sizes and for all storage sizes. The conclusion is, therefore that a strictly rational customer would not choose to add a storage system.

15 The 'with storage' results assume that the customer chooses a storage system of a size that delivers the best incremental return. The particular size of that storage system varies with system size and from quarter to quarter.

It should be noted, though, that the return on solar PV systems with storage is projected to become positive after the conclusion of the regulatory period. This may be sufficient to motivate some customers to add install solar PV systems with storage, notwithstanding that they would receive a larger return if they did not.

It would be overreaching to interpret this conclusion that a rational customer would not add storage to a solar PV system to mean that no such systems will be installed, as clearly some customers do not act solely on rational motives. In addition, there is a degree of heterogeneity in customer consumption patterns that is not accounted for within the model. Hence, there may be customers that could get a positive financial return from battery storage, that aren't considered explicitly within the model. Nevertheless, the financial analysis presented here leads us to project very limited uptake of storage systems. Accordingly, the core solar PV projections presented in section 6.5.2 were not adjusted to account for uptake of storage systems.

Figure 46 **Financial returns to Solar PV and storage systems**



Source: ACIL Allen Consulting

It is important to emphasise that these conclusions are sensitive to the battery cost trajectory outlined in section 6.6.2.

6.6.1 Export rates and storage systems

This section describes ACIL Allen's analysis of the way that export rates would be affected by the existence of a storage system. The underlying assumption is that customers will derive more value by consuming the electricity from their solar PV system 'on site' than by exporting it. This is consistent with the current situation where the value of 'on site' use is the retail price, which is significantly more than the based buyback rate. This is because the latter is based on the wholesale price of electricity while the former includes network costs.

Therefore, ACIL Allen assumed that customers with a storage system of a given size would use the output of their solar PV system to charge a battery system whenever its output exceeded their on-site use, as long as there was capacity in the battery to do so.

Export rates for systems with storage were estimated based on the same sample of 580 JEN customers as used for the estimation of export rates for systems without storage. Storage sizes were considered in 2 MWh increments, up to a maximum of 10MWh. For each customer in the sample:

- solar PV energy generation was compared to consumption in each half hour block.
- If generation is greater than consumption, the excess is stored in the battery (up to the battery capacity). Any excess over the battery capacity is exported.
- If generation is less than consumption, energy in the battery is used (until the battery is drained completely).

This produces a matrix of export rates for solar PV systems and batteries of different sizes, which is set out in Table 26. That table shows, for example, that a customer with a 3 kW solar PV system, who uses at least 2.5 MWh of electricity each year (from Table 25) and has no battery storage, will export, on average, 61 per cent of the output of their solar PV system. If the same customer was to install a 4 kWh battery storage system, they would reduce their exports to 31 per cent of the total output of their system. There is a declining return to storage size as well. This is due to the fact that some customers exhibit large levels of demand, or have demand curves that are well aligned to the solar output profile, and hence achieve a zero export rate at a much lower storage size than other customers.

Those storage rates were carried into the payback analysis using the same retail and export prices discussed above.

Table 26 **Estimated export rates (per cent of energy generated)**

	solar PV system size (kW)				
Storage capacity	1.5	2	3	4	5
No storage	49.3%	55.1%	61.0%	64.6%	66.6%
2 kWh	22.3%	31.5%	42.8%	50.1%	54.5%
4 kWh	13.0%	20.5%	31.4%	39.7%	45.1%
6 kWh	10.8%	16.5%	25.3%	33.1%	38.4%
8 kWh	10.1%	15.1%	22.6%	29.5%	34.2%
10 kWh	9.7%	14.5%	21.3%	27.7%	31.9%

Source: ACIL Allen Consulting

6.6.2 Forecasting battery prices and returns to storage

The other difference between the analysis of solar PV systems with and without storage is the cost of the storage system itself. The estimate of storage system cost was based on upfront battery installation costs and expected battery replacement costs.

The upfront cost of storage was calibrated based on a July 2013 presentation by ZEN Energy on its Freedom PowerBank product. This presentation indicated current battery costs for a 20 kWh system of:

- $1500 per kWh of storage capacity,
- $5000 in installation costs.

ACIL Allen assumed that 80 per cent of the installation cost of the storage system would vary with the size of the system, with this cost being $4000 for a 20 kWh system, or $200 per kWh of storage capacity. ACIL Allen further assumed a flat $1000 for an installation of any size.

Battery costs per kWh were assumed to be insensitive to system size due to the modular nature of battery installations (in practice installers may offer some discount for larger installations, but this appears difficult to predict at this stage).

Real installation costs were assumed to decline at 1 per cent per year (reflecting limited scope for reductions and relatively fixed costs associated with wiring), whereas battery costs were assumed to reduce at 15 per cent per year (reflecting large scope for improvement, not least due to the electric vehicle industry). Battery life was assumed to be 12 years or, for simplicity, one replacement during the 25 year life of the combined solar PV/storage system. The replacement cost was calculated as the net present value of the (reduced) installation cost 12 years after the initial battery installation.

The financial benefit of storage systems comes from the fact that the customer can avoid exporting electricity. The benefit is the difference between the buyback rate and the retail price each year. For example, at present prices, a customer would receive a benefit of approximately 19.5 c/kWh by using electricity from their solar PV system on site instead of exporting it because the retail price of electricity, which includes the cost of network services, is substantially higher than the buyback rate, which is based on the value of the energy alone.[16]

[16] 19.5 c/kWh is approximately the difference between the 2013 standing contract retail tariff, which was 27.65 c/kWh and the mandatory buyback rate in 2013, which was 8 c/kWh.

7 Smart meters and flexible pricing

In recent years smart meters have been rolled out to Victorian households. At the time of writing this rollout was in large part complete, with only a very small number of JEN's residential customers yet to have their meter replaced.

Smart meters will impact the way that DNSPs like JEN operate their networks in many ways. This includes changing the way meters are read, and allowing DNSPs to receive, and therefore respond to and share, much more detailed information about power outages than was possible with older metering technology. However, these aspects of smart metering are not expected to alter electricity demand or consumption.

The expected impact on demand and consumption will not be caused by smart meters as such, but by pricing structures that they enable. The fundamental characteristic of a smart meter is that it records the amount of electricity a customer uses in 30 minute blocks. By contrast, the meters that were replaced in Victoria, and remain in use in other states, only measure the amount of electricity used since the last time the meter was read.

With the information provided by smart meters, it is possible to charge different prices for electricity at different times of day. In Victoria this is known as 'flexible pricing'. This became permissible in Victoria in late 2013.

The particular tariffs that will be available to customers are unknown. In the competitive retail market in Victoria retailers have very broad discretion to set tariffs. A few flexible tariffs are available in Victoria at the time of writing this report, though JEN has advised that very few customers have chosen to take them up as yet. As time passes and flexible pricing matures it is likely that more customers will 'migrate' to flexible tariffs. It is also likely that retailers will innovate and develop new tariff structures.

7.1 Model overview

The model developed by ACIL Allen estimates the impact on demand and consumption as customers migrate from flat to flexible tariffs. It does this by estimating the impact on demand and consumption of a single customer in each half hour of the year and multiplying this by the number of customers assumed to migrate.

The conceptual basis of the model is that customers have a choice between a flat rate and a flexible tariff. When a customer chooses to move from the flat rate to the flexible tariff they choose to pay a price that depends on the time of day that the electricity is used.

The impact that flexible pricing will have on demand and consumption was estimated by applying an estimate of the price elasticity of demand to difference between:

1. the price the customer would pay if they remain on a flat tariff
2. the price they would pay if they migrated to a flexible tariff.

This estimate was prepared for each half hour of the year independently. Results can be aggregated to provide estimates of the impact on:

- demand in each half hour and therefore on maximum periodic demand
- consumption over a specified time period
- JEN's revenue.

The inputs to the model are:

— the load profile of the representative customer, which is discussed in section 7.2
— the tariffs available to that customer, which are discussed in section 7.3
— the price elasticity of demand, which is discussed in section 0
— the rate at which customers are expected to shift from flat to flexible tariffs (migration rate), which is discussed in section 7.5.

Results are provided in section 7.6.

While all of the above inputs are important in the model, perhaps the most uncertain are the price elasticity of demand and the migration rate.

The assumed price elasticity of demand is based on a literature review. That review, shows that there are gaps in the relevant literature. In particular, it seems widely accepted that, at least in the short term, demand for electricity is less responsive to price on very hot days than it is at other times, due to air conditioning use. However, how much less responsive it is has not been quantified. It would be unreasonable, in our view, to apply the full price elasticity on very hot days as at other times. Therefore, ACIL Allen made an assumption about the nature of that relationship in the main modelling based on its analysis of the relationship between demand and temperature in JEN's region.

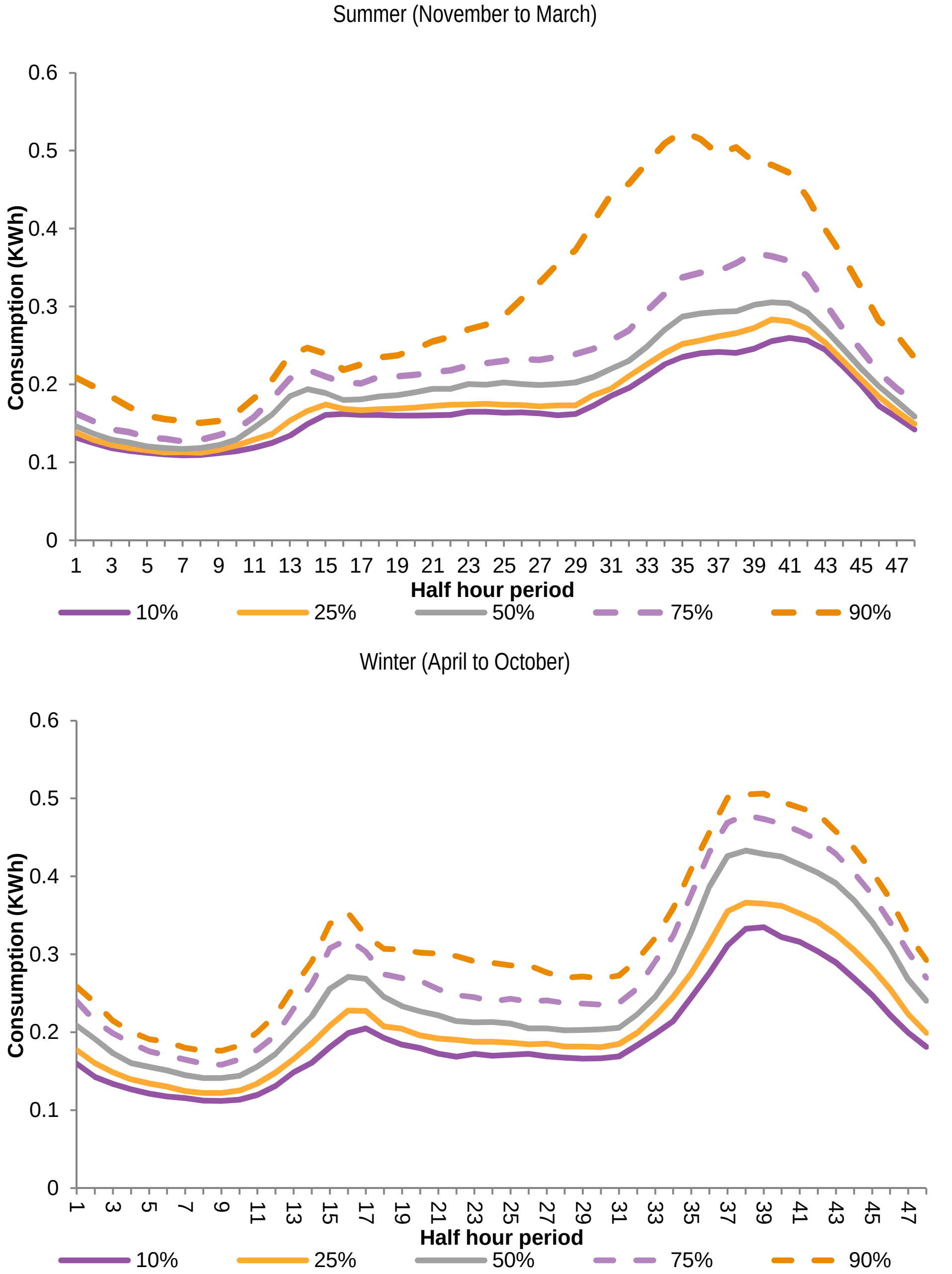
7.2 The representative customer

The starting point of the model is the load profile of a representative customer on a flat tariff based.

JEN provided half hourly consumption data from calendar 2013 for a sample of 1,000 customers, of which 500 were on the A100 tariff. That sample was averaged to provide a single, half hourly load profile that was taken to be representative of JEN's A100 tariff customers.

This half hourly load profile, which formed the basis of the modelling, is summarised in Figure 47, which shows the spread of daily loads in summer and winter periods.

Figure 47 **Base year (2013) load profile, by percentile**



Source: ACIL Allen Consulting analysis of JEN customer sample

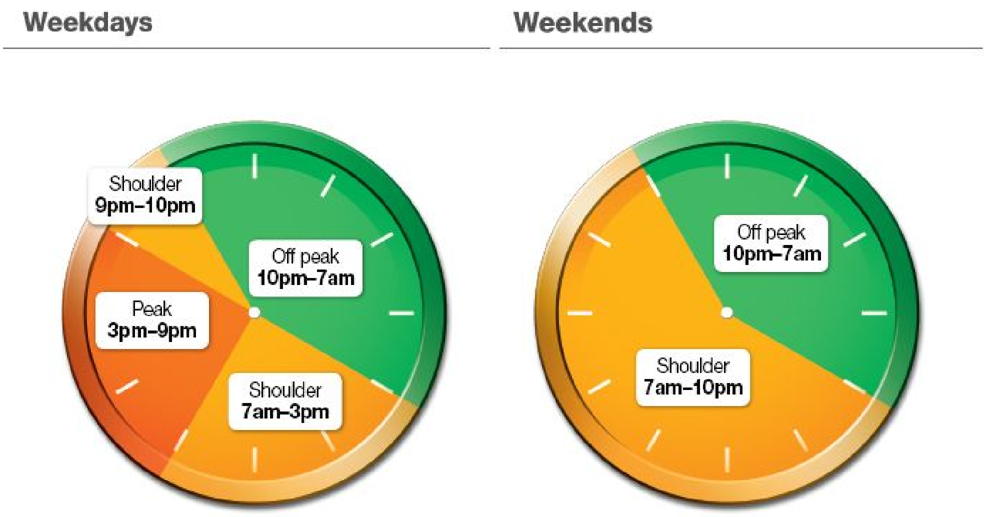
The same load shape was replicated for each of the ten forecast years, with the overall level scaled to reflect changes in consumption developed through the consumption forecast model.

The base year is, therefore, a matrix of load readings which is 364 (52 weeks by 7 days) days 'high' and 48 half hourly periods 'wide'. The 'structure' of the base year was replicated in each forecast year. Public holidays, days of the week, and weekends, reflect 2013 rather than the actual future year. Leap years are disregarded.

7.3 Flexible pricing – tariffs

Broadly, it is expected that flexible tariffs will be structured as shown in Figure 48, which was adapted from a Victorian Government website. It shows that tariffs are expected to have three pricing bands, with different prices applying at off peak, shoulder and peak times. The figure shows when the different pricing bands are expected to be applied.

Figure 48 **Illustrative flexible tariff**



Peak: The price of electricity is higher during the ‘peak’, typically on weekday afternoons and evenings, when the demand for electricity is the highest.

Shoulder: The price of electricity is lower than the peak rate and higher than the off-peak rate, when there is a reduced demand for electricity.

Off-peak: The price of electricity is lowest, when the demand for electricity is the lowest.

Source: http://www.switchon.vic.gov.au/flexible-pricing/how-flexible-pricing-works

With flexible pricing it is likely that the price of electricity will be:

- highest during peak times, on weekday afternoons
- lowest at off-peak times, overnight
- between these two levels at shoulder times.

However, the specific price of electricity at any given time will be determined in the competitive market. Retailers will decide the prices they will offer as well as the timing and number of pricing bands, and customers will choose which offer to accept.

For modelling purposes ACIL Allen reviewed the flexible tariffs that were being offered by large retailers in the market at the time of writing. That review of the retail market in Victoria showed that the three largest retailers offer the flexible prices summarised in Table 27. JEN’s corresponding Network Use of System (NUOS) tariffs are included to illustrate the difference between distribution and retail tariffs.

Table 27 **Observed flexible pricing offers**

	Peak	Shoulder	Off peak	Daily
	c/kWh	c/kWh	c/kWh	c/day
AGL (Summer[a])	39.402	26.466	20.977	100.947
Origin	43.43	25.949	20.581	110.539
Energy Australia	40.15	20.79	19.8	105.9
	c/kWh	c/kWh	c/kWh	c/day
JEN (A10X)	14.201	8.900	4.275	n/a

Note: all prices are GST inclusive

Source: for retail prices - AGL and Origin websites, accessed 31 January 2014 and telephone conversation with Energy Australia on 31 January 2014. For NUOS – JEN

For modelling purposes ACIL Allen constructed a single representative tariff. This was based on JEN's A10X tariff with mark ups applied to each component as shown Table 28. The mark ups were based on ACIL Allen's review of retail prices in the market.

The result was a tariff that:

— reflect's JEN's existing time of use NUOS tariff
— is similar to those available in the market (as set out in Table 27)
— is not necessarily the same as the tariff offered by any given retailer.

Note that A10X has a lower peak charge in winter than in summer. Of the three largest retailers, only AGL appears to offer different prices in winter than summer. JEN's tariff has this structure, so it is also present in the modelling.

The modelling is based on the difference between the two tariffs available to the customer, i.e. a flexible pricing option and a flat tariff so it was also necessary to construct a flat tariff for comparison, which is also shown in Table 28. This was based on JEN's A100 tariff with a mark-up at a level based on ACIL Allen's observations of retail price offers.

All tariff mark-ups were held constant in nominal terms throughout the projection period, which is appropriate because the objective here is to model the impact of the differences between the flat and flexible tariffs. The impact of rising average prices is dealt with separately through the models described in chapter 5.

Table 28 **Assumed retail tariffs for modelling**

	Peak	Shoulder	Off Peak
	c/kWh	c/kWh	c/kWh
		Flexible tariff	
NUOS	14.201	8.900	4.275
Mark-up	24.000	18.000	17.000
Total	38.201	26.900	21.275
		Flat tariff	
NUOS		8.900	
Mark-up		19.000	
Total		27.900	

Source: ACIL Allen Consulting

7.4 Price elasticity of demand

In the model, the impact on consumption and demand is the result of changes in the load profile of the representative customer that are aggregated to account for the number of customers who migrate.

The changes in the load profile are driven by the difference between the tariffs shown in Table 28 and estimates of the price elasticity of demand.

Rather than a single value for price elasticity, a table of own and cross price elasticities is used. These reflect the results of Energy Australia's[17] TOU Tariff Study. The elasticities also differ between summer and winter. The elasticities are shown in Table 29.

Table 29 **Price elasticity of demand**

	Off peak	Shoulder	Peak
Off peak	0.00	0.00	0.00
Shoulder	0.00	-0.10	0.00
Peak	0.10	0.08	-0.30 (-0.47)

Note: Change in price is denoted by the row tariff type, while the change in demand is denoted by column tariff type. Values in parentheses are applicable in winter.

Source: ACIL Allen Consulting

These elasticities in Table 29 imply that:

- for every one percent increase in the price of electricity in the peak period relative to the flat tariff demand for electricity:
  - increases by 0.1 per cent in the off-peak period
  - increases by 0.08 per cent in the shoulder period
  - decreases by 0.3 per cent in the peak period in summer, and by 0.47 per cent in winter.
- for every one percent increase in the price of electricity in the shoulder period, relative to the flat tariff, demand for electricity decreases by 0.1 percent in the shoulder period
- the price of off peak demand on a flexible pricing tariff, relative to the flat tariff, has no impact on demand in any period

Therefore, consistent with the relative prices, the result is that electricity usage:

- increases in off peak and winter shoulder periods
- decreases in peak and summer shoulder periods.

7.4.1 The interaction between price elasticity and extreme temperature

As mentioned above, it appears to be accepted that electricity demand is less responsive to price on very hot days than at other times, at least in the short run. However, the extent of this has not been quantified in the literature. This was addressed in the model by distinguishing between 'heat sensitive' and 'non heat sensitive' demand.

To do this ACIL Allen estimated the portion of total demand that was heat sensitive as a function of the maximum temperature observed during each day in 2013 at the Melbourne Airport Weather Station.

This was done by regression analysis using the base year dataset describe above and temperature observed in 2013 at the Melbourne Airport weather station. The regression used a combination of temperature and non-temperature related variables, including time of day, workday and seasonal dummy variables. The proportion of explained variation that the

[17] This refers to the former name of Ausgrid, the New South Wales DNSP. It should not be confused with the company currently names Energy Australia, which is a generator and retailer formerly known as TRU Energy.

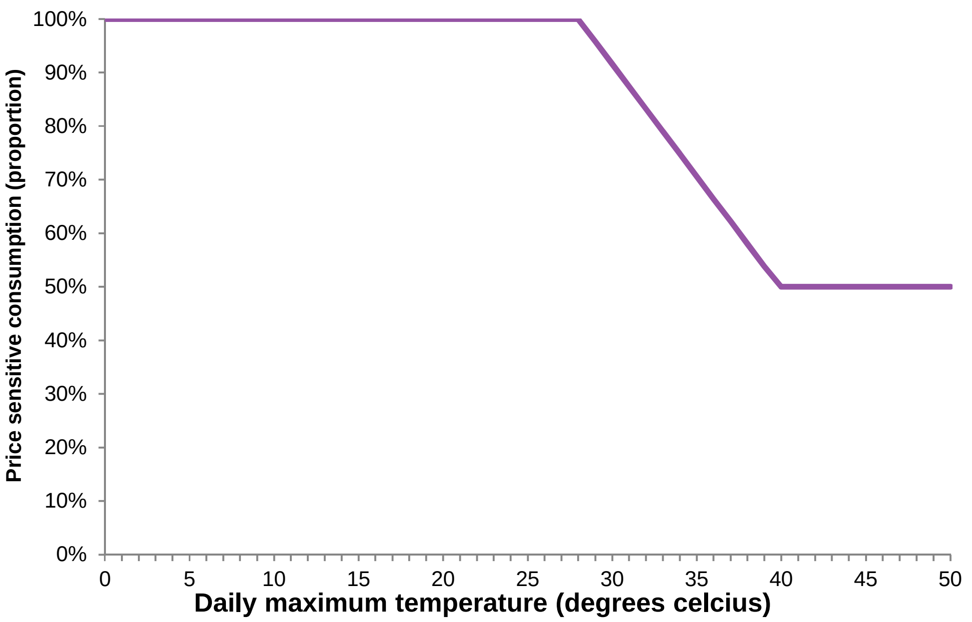
temperature-related variables accounted for was then used as a proxy for the price-inelastic temperature-influenced demand.

This information was aggregated to determine the proportion of demand which is price sensitive for days with various temperatures, which was in turn used to inform the elasticity adjustment curve. The estimated elasticity adjustment curve was consistent with previous analyses ACIL Allen has conducted, with heat

In effect, the implication is that, for every one degree increase in temperature over 28 degrees, the proportion of demand that is heat-sensitive, and hence price-insensitive, increases by 4.2 percentage points. This is bound at fifty per cent (at 40 degrees maximum temperature) to reflect the view that heat-sensitive demand reaches a saturation point at around 50 per cent.[18]

The assumed relationship is illustrated in Figure 49.

Figure 49 **Portion of consumption which is non-heat sensitive**



Source: ACIL Allen Consulting

The percentage of consumption categorised as 'heat sensitive' through this process was 'quarantined' from the price elasticity.

As shown in Figure 49, the portion of heat sensitive load varies from zero, when the daily maximum temperature is 28C or less, to 50 per cent when the daily maximum temperature is 40C or above. When this is applied to the model it amounts to an assumption that consumption is

- price elastic as shown in Table 29 when maximum temperature is no greater than 28C
- half as price elastic as shown in Table 29 when maximum temperature is 40C or higher
- between these two levels when maximum temperature is between 28C and 40C.

18 Australian Energy Market Operator, "South Australian Supply Demand Outlook", 31 March 2011, p. 15

7.5 Migration rate

The next step was to account for the number of customers who would change from a flat tariff to a flexible tariff.

When this modelling was conducted flexible pricing had been available in Victoria for approximately eleven months and only a very small number of customers had migrated. At this early stage retailers do not appear to be actively seeking to persuade customers to change to flexible tariffs.

In all likelihood the rate at which customers change to flexible tariffs will increase as the new tariffs 'bed down' in the market. However, it is not possible to make a firm prediction of the rate at which this will happen. For modelling purposes it was assumed that there would be 1,000 customers on flexible tariffs in JEN's region in 2014 and that 100 customers would migrate to flexible tariffs each following year throughout the regulatory period.

7.6 Results

The results presented are estimates of the impact of migration from flat to flexible tariffs on:

- residential maximum periodic consumption - section 7.6.1
- residential consumption - section 7.6.2
- revenue from residential customers -section 7.6.3.

7.6.1 Residential maximum periodic consumption

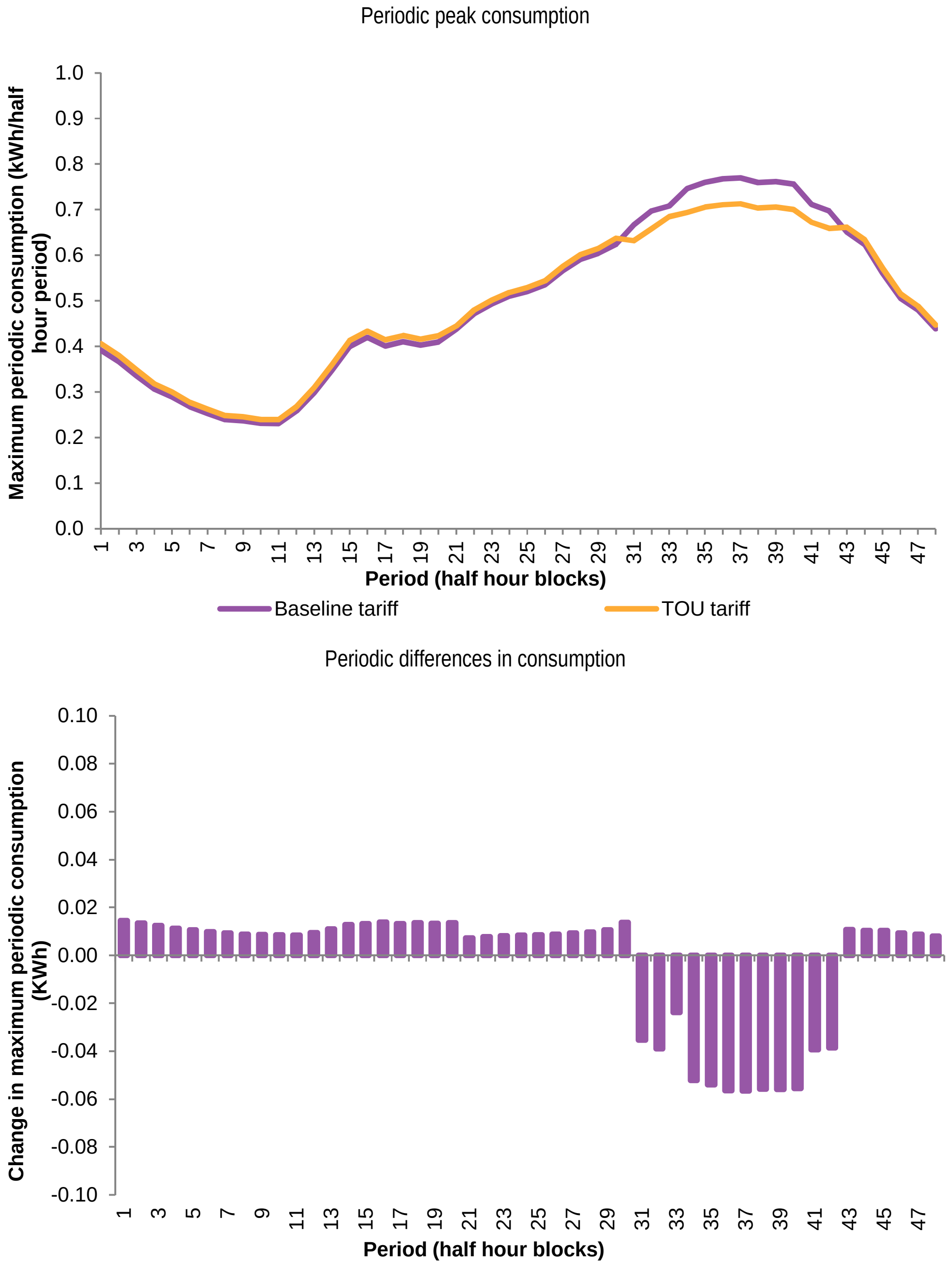
The estimated reduction in maximum periodic consumption from an individual customer who switches from a flat to a flexible tariff is shown in Figure 50.

Figure 50 shows what appears to be a load profile, but is not. Rather than being the load observed on a single day, this figure shows the difference between the load of these two customers when baseline load is highest. In other words, the curves show the maximum load observed in each of the 48 periods for a customer under a flat tariff structure, compared to that of a customer under a flexible tariff structure. The loads corresponding to each time period will not necessarily occur on the same day.

The reduction in maximum periodic consumption is small. The reason for this varies between the different time periods:

- in peak periods it is mainly due to the heat sensitivity assumption discussed in section 0. At peak times maximum demand occurs mainly on very hot days when consumption is assumed to be less responsive to price than at other times
- in off peak and shoulder periods the impact on maximum periodic consumption is small because the elasticity is small.

Figure 50 **Impact of migrating to flexible pricing for a representative customer, in 2020**



Source: ACIL Allen Consulting

Figure 50 relates to a single representative customer changing from a flat tariff, to a flexible pricing tariff. The estimated impact on JEN's customer base as a whole is presented in Figure 51. The levels shown in Figure 51 are the weighted sum of the load of those customers on the A100 tariff, and those on the A10X pricing tariff, in this case in the seventh forecast year (2020), when approximately 45 per cent of JEN's customers are assumed to have migrated to flexible pricing.

The changes exhibited in Figure 51 are difficult to discern, mainly due to the fact that the assumed migration rate to flexible tariffs is very low.

Figure 51 **Aggregate changes to customer loads at 2020**

Source: ACIL Allen Consulting

7.6.2 Residential consumption

The figures in section 7.6.1 only relate to the periods when demand is at its maximum. The impact on consumption is driven by all periods.

Given the parameters discussed above, ACIL Allen projects the impact of flexible pricing on consumption by residential customers will be as shown in Table 30.

Table 30 **Estimated impact of flexible pricing on consumption by year and tariff component**

	2016	2017	2018	2019	2020
	GWh	GWh	GWh	GWh	GWh
Summer					
Peak	-0.022	-0.027	-0.033	-0.038	-0.043
Shoulder	0.012	0.015	0.018	0.021	0.024
Off Peak	0.008	0.010	0.012	0.014	0.015
Non-summer					
Peak	-0.042	-0.051	-0.061	-0.071	-0.081
Shoulder	0.015	0.019	0.022	0.026	0.030
Off Peak	0.011	0.013	0.015	0.018	0.021

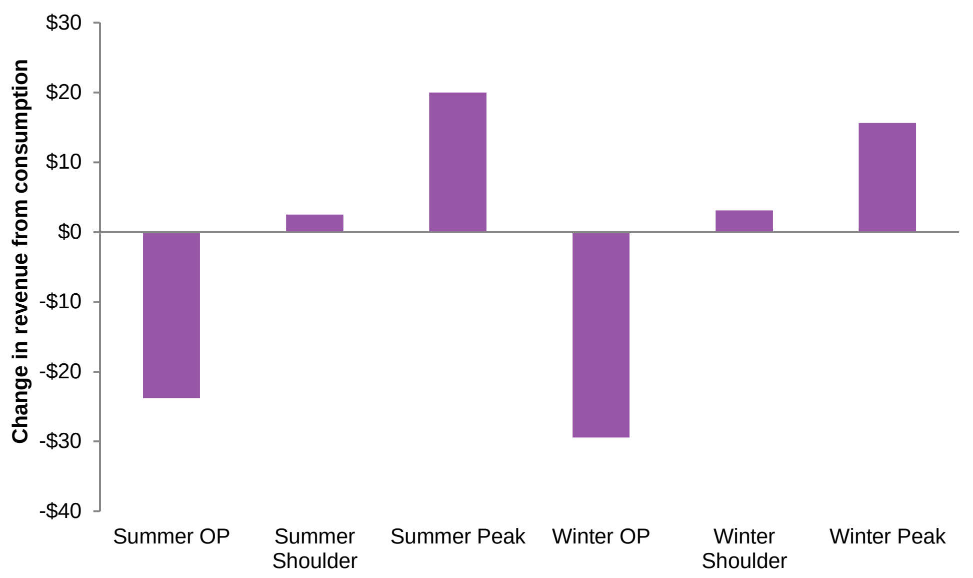
Source: ACIL Allen Consulting

7.6.3 Revenue from residential customers

The modelling indicates that, using 2013 tariff levels, and assuming that price elasticity is sensitive to temperature as described above, the representative JEN customer who switches will save $18.86 per annum on their retail bill. However, JEN's revenue is only a portion of total retail spending. With the particular assumptions made here, JEN can expect to forego $11.92 in revenue (once again, using 2013 tariff levels) for each customer who chooses to migrate in 2020 on average. However, this assumes that customers that migrate have consumption that is representative of JEN's overall residential consumption profile. In practice, the impact may be more than this if customers choose to migrate based on whether, with their individual usage profile, they can expect to save money by doing so.

Figure 52 shows the impact on JEN's revenue broken down by 'price band'. It shows that migrating customers are estimated to yield around $24 less for off-peak electricity in summer, and $20 more for peak period electricity. In winter, these figures change to $29 less for off-peak, and $16 more for peak. Shoulder periods would raise $3 per switching customer per summer/winter ($6 per year overall).

Figure 52 **Change to JEN revenue for representative migrating customer, 2020**



Source: ACIL Allen Consulting

The gross impact on JEN's revenue will be driven by the rate at which customers choose to migrate and by the DUOS tariffs that apply. Given that DUOS tariffs are a function of demand, they have not been projected for the purpose of analysis of TOU pricing.

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