Jemena Electricity Networks (Vic) Ltd

2016-20 Electricity Distribution Price Review Regulatory Proposal

Attachment 3-1

Electricity demand forecasts report

Public

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ACIL ALLEN CONSULTING

A REPORT TO
JEMENA ELECTRICITY NETWORKS

20 NOVEMBER 2014

ELECTRICITY DEMAND FORECASTS

REPORT

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Executive summary

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 seven terminal stations and 23 zone substations owned by JEN.

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 maximum demand, 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 demand. A separate report relates to consumption and customer numbers.

The results presented in this report were prepared using econometric techniques using the methodology ACIL Allen prepared for the Australian Energy Market Operator to use in forecasting demand at the terminal station (connection point) level.

In summary:

- regression models were estimated to quantify the relationship between electricity demand and its drivers
- those models were used with projections of the drivers to produce baseline forecasts.
- separate models were prepared for each terminal station (bottom up) and for demand in JEN's region as a whole (top down) and the terminal station forecasts were reconciled with the system level forecasts

A post model adjustment was made to the residential forecasts to account for the impact of ongoing take-up of solar PV systems. That impact was calculated in separate models described in this report.

Adjustments were also made to the terminal station models before reconciliation to account for a small number of large loads anticipated in certain parts of JEN's network.

The process was conducted separately for summer and winter to produce independent forecasts of maximum demand in these seasons.

A summary of the key summer results follows. Winter results are presented in the body of the report.

Maximum summer demand – system level

The forecasts of maximum demand at the system level are shown in Table ES 1. This shows the raw forecasts, the amount of solar PV, and the final forecasts, which are net of the output of solar PV.

Table ES 1**System maximum demand forecasts, 2014-15 to 2023-24**

	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	CAGR
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%
10 POE – raw	1021.4	1036.5	1052.1	1070.4	1087.1	1104.7	1122.3	1136.9	1160.2	1176.6	1.58
50 POE – raw	938.4	950.3	965.3	980.8	995.5	1010.7	1026.2	1043.6	1060.3	1072.4	1.49
90 POE – raw	870.8	880.7	895.6	906.7	926.2	936.1	949.1	963.3	982.6	989.3	1.43
Solar PV (impact of new systems only)	2.21	3.72	5.77	7.86	10.00	9.04	10.69	12.37	14.08	15.81	24.44
10 POE - final	1019.2	1032.8	1046.3	1062.6	1077.1	1095.7	1111.6	1124.5	1146.1	1160.8	1.46
50 POE – final	936.2	946.6	959.5	973.0	985.5	1001.7	1015.5	1031.2	1046.2	1056.6	1.35
90 POE - final	868.5	877.0	889.8	898.8	916.2	927.1	938.4	951.0	968.5	973.5	1.28

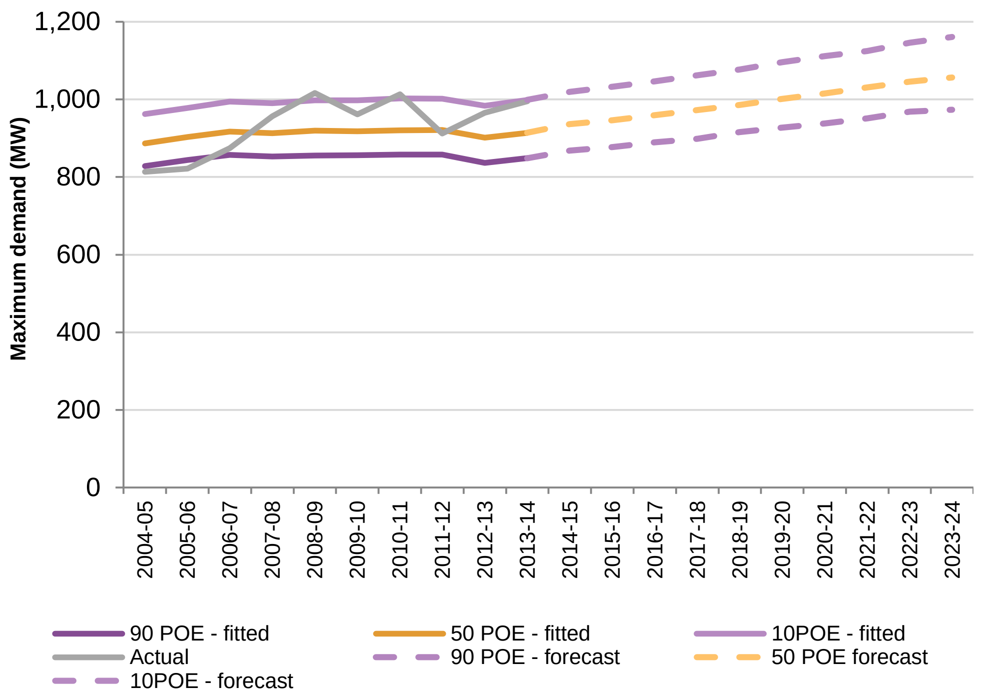
Note: the impact of solar PV at peak times shown here is for new systems only so it comes off a very low base. This exaggerates the solar PV Compound Annual Growth Rate (CAGR). If the existing solar PV systems are taken into account for the purpose of the CAGR calculation, growth (CAGR) in the impact of solar PV is approximately 4.4% over the forecast period. Also note that this is not the forecast capacity of PV systems, but the forecast impact at peak times.

Source: ACIL Allen Consulting

Figure ES 1 shows the forecasts from Table 2 in graphical form. To place these in context it also shows historical maximum demand, both actual and weather normalised.

As Table ES 1 and Figure ES 1 show, maximum demand is forecast to grow over the forecast period largely driven by a projected return to trend GDP growth and a stabilisation of electricity prices. At the 50 POE level the projection is for annual growth of 1.35 per cent.

Figure ES 1 **JEN system level maximum summer demand – actual and forecast, 2004-05 to 2023-24**



Source: ACIL Allen Consulting

Maximum summer demand – terminal station level

The forecasts of non-coincident maximum demand at the terminal station level are shown in Table ES 2 and, graphically, in Figure ES 2 (50 POE) and Figure ES 3 (10 POE).

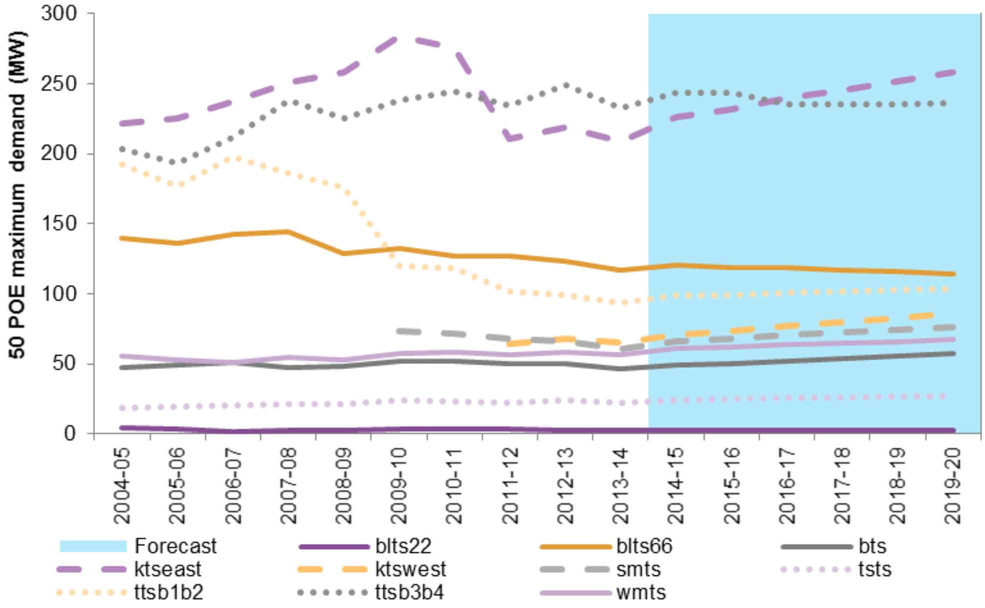
As is shown, the projection is that demand growth at the terminal station level will be quite flat. Averaged across all terminal stations the projected growth rate is 1.53 per cent per annum (at the 50 POE level).

Table ES 2**Terminal station non-coincident maximum demand forecasts, summer 2014-15 to 2023-24**

Terminal station	POE	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	CAGR
	%	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%
BLTS22	10	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	0.00%
	50	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	0.00%
	90	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	0.00%
BLTS66	10	128.7	127.5	127.5	126.3	124.9	124.0	122.8	121.2	120.4	118.9	-0.88%
	50	120.6	119.0	118.9	117.4	115.8	114.6	113.1	111.8	110.4	108.4	-1.18%
	90	113.8	112.0	112.1	110.2	109.3	107.6	105.9	104.4	103.4	100.9	-1.32%
BTS	10	54.5	55.7	58.1	60.7	62.6	64.1	65.5	66.1	67.1	67.8	2.45%
	50	48.9	49.8	52.0	54.3	55.9	57.2	58.3	58.8	59.3	59.6	2.22%
	90	43.8	44.5	46.5	48.4	50.2	51.0	51.8	52.0	52.5	52.3	1.99%
KTS East[a]	10	247.8	252.8	260.3	265.7	270.8	277.1	282.8	287.8	295.2	300.7	2.17%
	50	226.4	231.6	240.1	245.8	251.6	258.4	264.7	271.7	278.5	284.1	2.56%
	90	207.4	212.7	221.7	226.9	234.4	240.5	246.7	253.4	261.5	266.3	2.82%
KTS West	10	79.6	82.5	86.3	89.5	92.7	96.5	100.1	103.6	108.1	112.1	3.87%
	50	70.9	73.5	77.1	80.0	83.0	86.5	89.9	93.7	97.5	101.0	4.01%
	90	63.3	65.7	69.2	71.7	75.1	78.0	81.1	84.5	88.5	91.5	4.17%
SMTS	10	69.4	71.5	74.4	76.6	78.8	81.4	83.8	86.0	88.9	91.3	3.10%
	50	65.8	67.6	70.4	72.4	74.4	76.7	78.8	81.2	83.5	85.4	2.94%
	90	63.1	64.8	67.6	69.3	71.6	73.5	75.5	77.6	80.1	81.6	2.90%
TSTS	10	27.3	27.9	28.8	29.5	30.1	30.9	31.6	32.3	33.2	33.9	2.44%
	50	24.2	24.7	25.5	26.1	26.6	27.2	27.8	28.5	29.1	29.6	2.25%
	90	21.5	21.9	22.6	22.9	23.4	23.8	24.2	24.6	25.2	25.4	1.86%
TTSB1B2	10	107.0	107.8	109.6	110.5	111.3	112.6	113.5	114.2	115.8	116.6	0.96%
	50	99.0	99.5	101.2	101.8	102.4	103.4	104.1	105.1	105.9	106.3	0.79%
	90	92.4	92.7	94.6	94.8	95.9	96.4	96.9	97.6	98.8	98.7	0.74%
TTSB3B4	10	264.1	265.4	258.3	259.7	260.7	262.8	264.3	265.1	267.8	268.9	0.20%
	50	243.5	243.4	235.5	235.6	235.7	236.6	236.9	237.8	238.3	237.8	-0.26%
	90	230.2	229.5	221.5	220.4	221.4	220.9	220.5	220.4	221.4	219.4	-0.53%
WMTS	10	66.9	68.3	70.3	71.8	73.2	75.0	76.5	78.0	80.0	81.5	2.22%
	50	60.8	61.8	63.6	64.7	65.8	67.2	68.5	69.9	71.2	72.3	1.94%
	90	54.9	55.5	57.0	57.6	58.7	59.4	60.2	61.1	62.3	62.7	1.48%

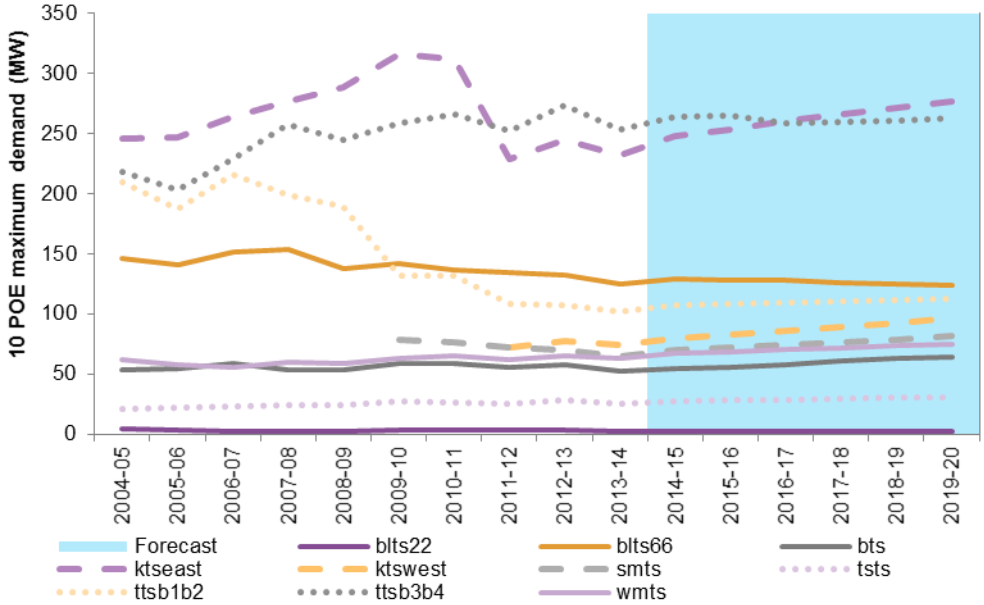
Source: ACIL Allen Consulting

Figure ES 2 **Terminal station non-coincident maximum demand 50 POE fitted and forecast data, summer 2004-05 to 2023-24**



Source: ACIL Allen Consulting

Figure ES 3 **Terminal station non-coincident maximum demand 10 POE fitted and forecast data, summer 2004-05 to 2023-24**



Source: ACIL Allen Consulting

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1 Introduction

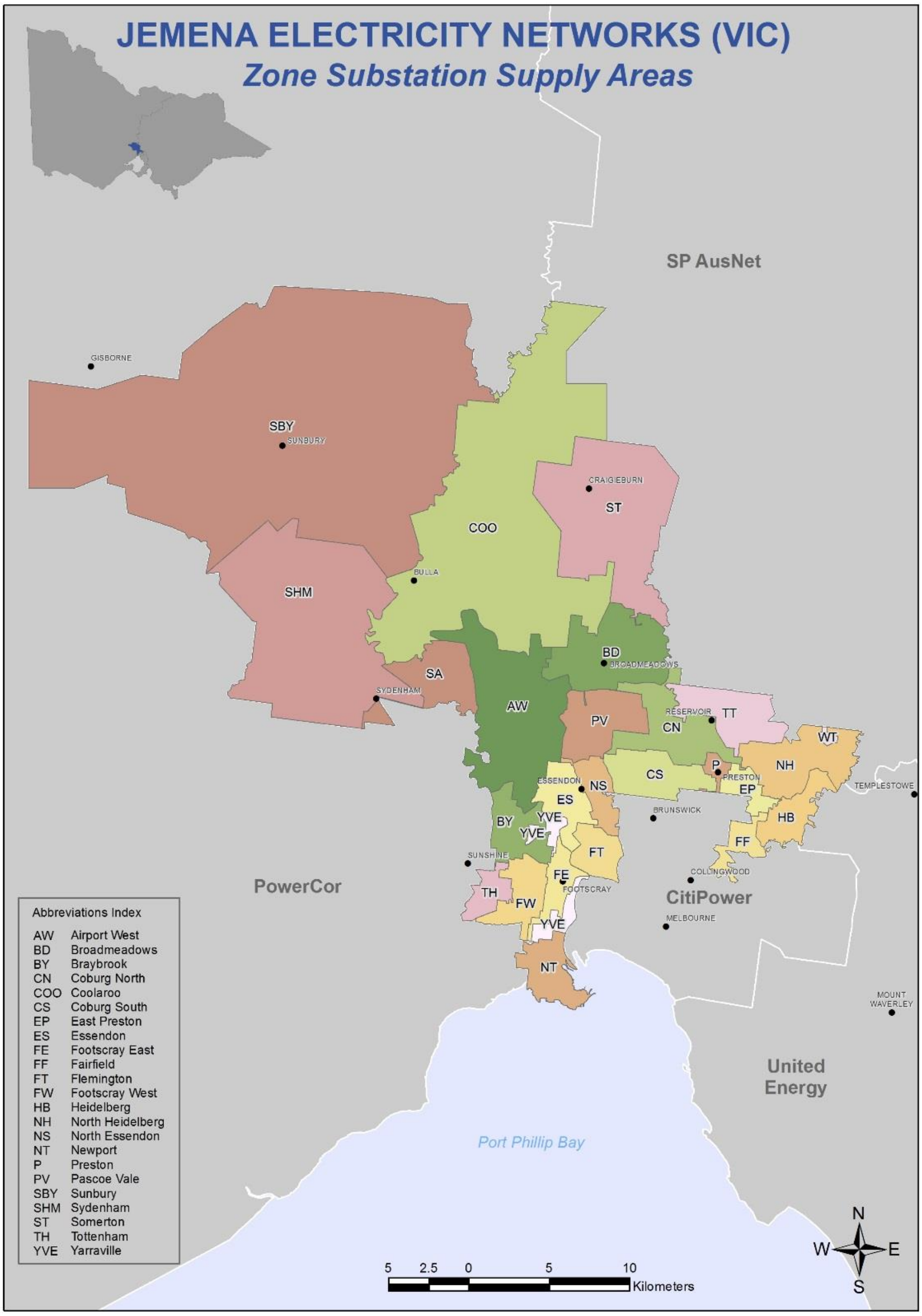
Jemena Electricity Networks (JEN) is an electricity Distribution Network Service Provider (DNSP). It distributes electricity to over 300,000 customers throughout the north-west of Melbourne. JEN's network comprises seven terminal stations and 23 zone substations owned by JEN as shown in Figure 1.

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 maximum demand, 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. 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 concepts.

This report contains forecasts of maximum demand. Projections of consumption and customer numbers are presented in a separate report. To prevent confusion, these terms and others are defined in section 1.1.

Figure 1 **JEN distribution region**



Data source: JEN Distribution Annual Planning Report 2013

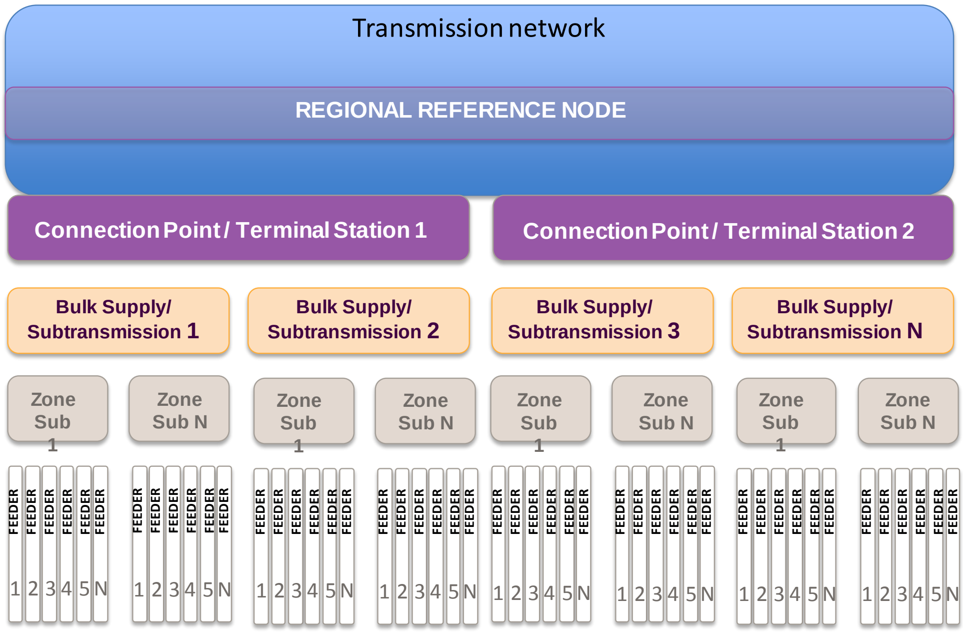
1.1 Definitions

The general configuration of an electricity network is illustrated in Figure 2.

- electricity is generated and transferred on a transmission network at high voltage
- a transmission network meets a distribution network at a terminal station

- a distribution network transfers electricity from a terminal station to a zone substation at a lower voltage[1]
- a distribution network transfers electricity to small customers at a further reduced voltage on a feeder.

Figure 2 **Typical hierarchy of electricity distribution network**



This following are definitions of important terms used in this report.

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[2] (at the network level, usually gigawatt hours, or GWh). Mathematically, consumption is equal to average demand multiplied by the number of hours over which demand is measured.

Demand refers to the rate of electrical power flow 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). Demand is measured at a particular point in the network. It may be less than latent demand due to the influence of embedded generation.

Latent demand is the total demand at a given time, including that which does not pass through the network element where demand is measured. It may be greater than demand due to an embedded generator(s) which supplies electricity to customers in a way that is not reflected in demand as measured at a given network element.

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[1] Some networks have sub-transmission stations between these two levels.

[2] Joules can also be used.

Terminal station is a physical point at which JEN's network is connected to the electricity transmission network. There are seven terminal stations with a total of 10 independent bus groups supplying JEN's network, listed in Table 1.

Table 1 **JEN terminal stations**

Terminal station	Abbreviation
Brooklyn TS 22kV	blts22
Brooklyn TS 66kV	blts66
Brunswick TS	bts
Keilor TS East	ktseast
Keilor TS West	ktswest
South Morang TS	smts
Templestowe TS	tsts
Thomastown TS	ttsb1b2
Thomastown TS	ttsb3b4
West Melbourne TS	wmts

Source: JEN

System level demand is the sum of the demand observed at each of JEN's terminal stations at any given time.

Coincident maximum demand exists at a given element of the network, either a terminal station or zone substation. It is the demand observed at that element when system level demand is at its maximum (that is, when the sum of demand at all network elements is at its maximum). Coincident maximum demand can be equal to or less than non-coincident maximum demand for that network element.

Non-coincident maximum demand is the maximum demand observed at a given element of the network. It may be equal to or greater than coincident maximum demand. It can be identified without regard to system level demand, and can occur at a different time to system level maximum demand.

Coincidence factor is the ratio of coincident to non-coincident demand.

Diversity factor is the reciprocal of coincidence factor.

Probability of exceedence (POE) refers to the likelihood that a given level of maximum demand will be met or exceeded:

– 50 POE maximum demand is the level of annual demand that is expected to be exceeded one year in two.
– 10 POE maximum demand is expected to be exceeded one year in ten.
– 90 POE maximum demand will be exceeded nine years in ten.

Summer is the period from 1 November to 31 March each year.

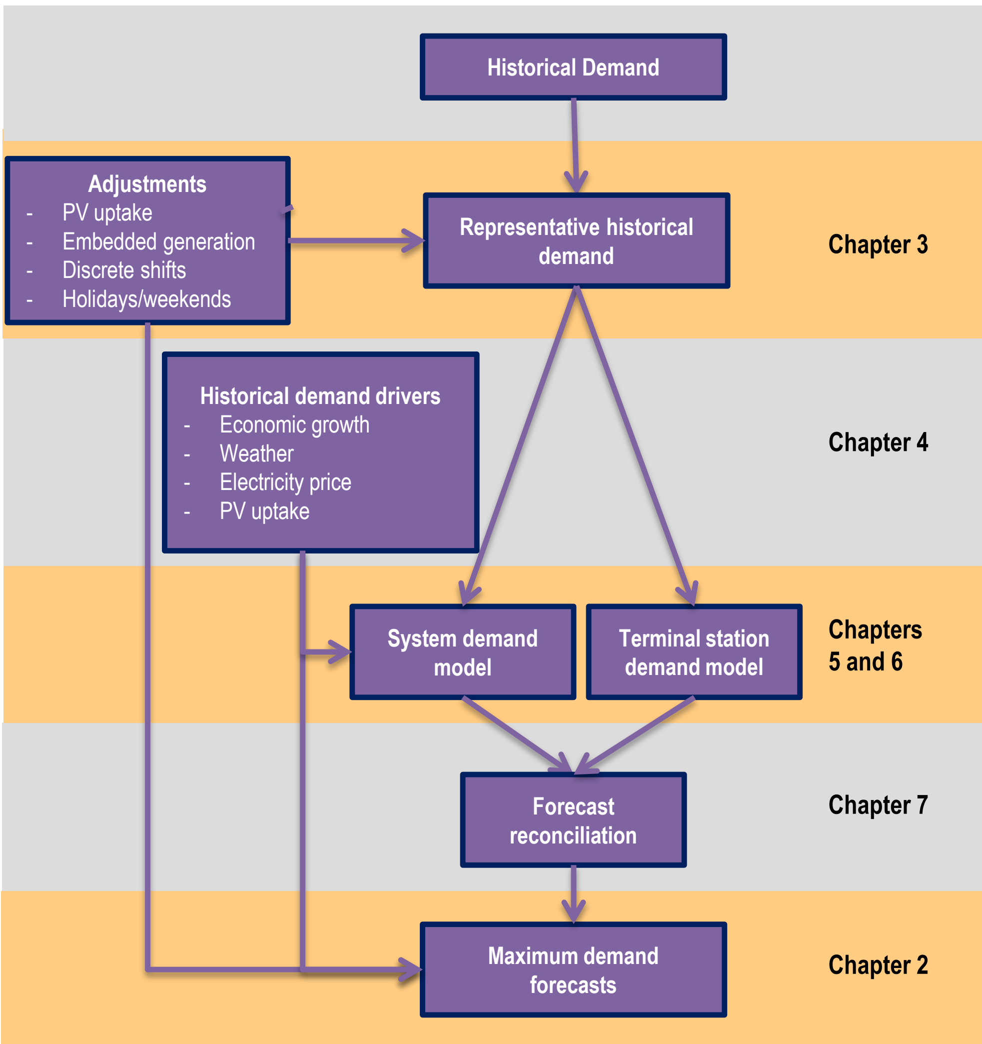
Winter is the period from 1 April to 31 October each year.

1.2 Overview of methodology and report structure

The methodology by which the forecasts were produced is illustrated in Figure 3. The steps were:

1. obtain historical data pertaining to maximum demand at each terminal station and at the system level
2. make adjustments to these data to approximate 'latent' demand by 'adding back' the impact of embedded generation and remove outliers and non-working days:
3. estimate regression models to relate demand to its drivers
4. forecast maximum demand using these regression models and projections of drivers
5. bootstrapping historical weather data to produce 10, 50 and 90 POE forecasts
6. reconcile the terminal station and system level forecasts
7. add back the (negative) effect of existing embedded generators and discrete demand shifts
8. make a post model adjustment to account for additional solar photovoltaic (PV) capacity.

Figure 3 **Conceptual diagram of maximum demand forecasting**



Source: ACIL Allen Consulting

This report is structured as follows.

The forecasts themselves are presented first, in chapter 2.

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

- Chapter 3 provides an overview of the history of demand within the JEN region.
- Chapter 4 provides an overview of the history of the drivers of demand.
- Chapter 5 provides a detailed description of the methodology by which the forecasts were prepared
- Chapter 6 describes the methodology used to project the uptake of solar PV capacity

Demand forecasts were prepared at each terminal station and at the system level independently of one another. The terminal station forecasts were then reconciled to the system level forecast.

Forecasts were prepared for summer and winter independently. The forecast periods are:

- for summer, 2014-15 to 2023-24
- for winter, 2014 to 2023

2 Demand forecasts

This chapter summarises the forecasts at both the system and terminal station level.

Section 2.1 relates to forecasts of maximum demand in summer.

Section 2.2 relates to forecasts of maximum demand in winter.

2.1 Summer forecasts

This section presents forecasts of maximum demand each summer from 2014-15 to 2023-24:

- section 2.1.1 provides forecasts of maximum demand at the system level
- section 2.1.2 provides forecasts of non-coincident maximum demand at the terminal station level
- section 2.1.3 provides forecasts of coincident maximum demand at the terminal station level.

The forecasts presented here have not been adjusted for the impact of embedded generators other than solar PV. This was done to allow JEN to incorporate its own view of the likely peak demand impact of those generators at the distribution feeder level.

2.1.1 System maximum demand forecasts

The forecasts of maximum demand at the system level are shown in Table 2. This shows the raw forecasts, the amount of solar PV, and the final forecasts, which are net of the output of solar PV.

Table 2 **System maximum demand forecasts, 2014-15 to 2023-24**

	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	CAGR
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%
10 POE – raw	1021.4	1036.5	1052.1	1070.4	1087.1	1104.7	1122.3	1136.9	1160.2	1176.6	1.58
50 POE – raw	938.4	950.3	965.3	980.8	995.5	1010.7	1026.2	1043.6	1060.3	1072.4	1.49
90 POE – raw	870.8	880.7	895.6	906.7	926.2	936.1	949.1	963.3	982.6	989.3	1.43
Solar PV (impact of new systems only)	2.21	3.72	5.77	7.86	10.00	9.04	10.69	12.37	14.08	15.81	24.44
10 POE - final	1019.2	1032.8	1046.3	1062.6	1077.1	1095.7	1111.6	1124.5	1146.1	1160.8	1.46
50 POE – final	936.2	946.6	959.5	973.0	985.5	1001.7	1015.5	1031.2	1046.2	1056.6	1.35
90 POE - final	868.5	877.0	889.8	898.8	916.2	927.1	938.4	951.0	968.5	973.5	1.28

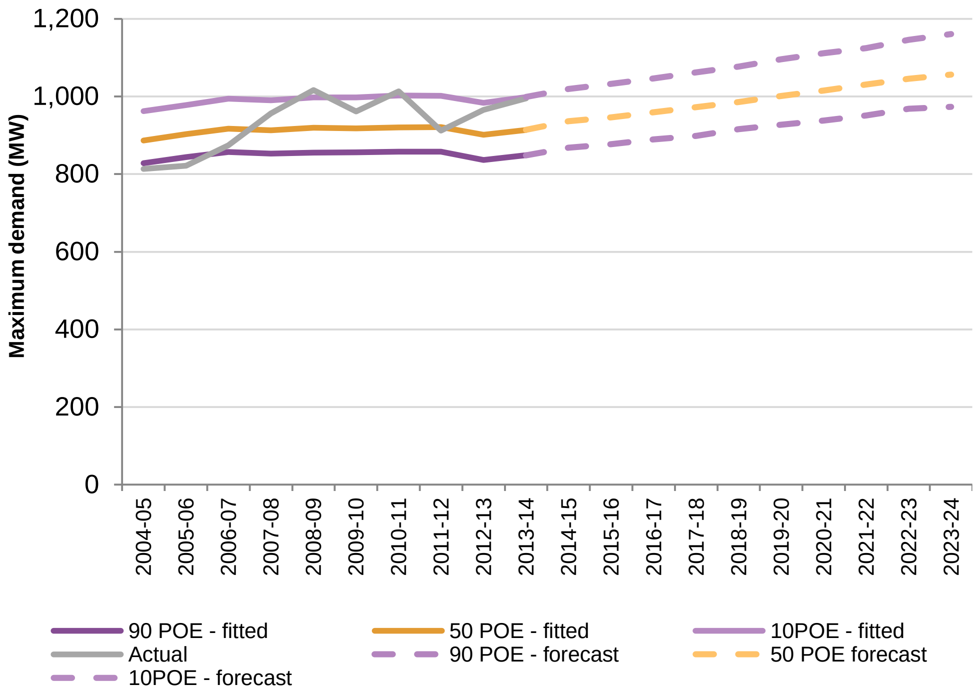
Note: the impact of solar PV at peak times shown here is for new systems only so it comes off a very low base. This exaggerates the solar PV Compound Annual Growth Rate (CAGR). If the existing solar PV systems are taken into account for the purpose of the CAGR calculation, growth (CAGR) in the impact of solar PV is approximately 4.4% over the forecast period. Also note that this is not the forecast capacity of PV systems, but the forecast impact at peak times.

Source: ACIL Allen Consulting

Figure 4 shows the forecasts from Table 2 in graphical form. To place these in context it also shows historical maximum demand, both actual and weather normalised.

As Table 2 and Figure 4 show, maximum demand is forecast to grow over the forecast period largely driven by a projected return to trend GDP growth and a stabilisation of electricity prices as discussed in chapter 4. At the 50 POE level the projection is for annual growth of 1.35 per cent.

Figure 4 **JEN system level maximum summer demand – actual and forecast, 2004-05 to 2023-24**



Source: ACIL Allen Consulting

2.1.2 Terminal station non-coincident summer maximum demand forecasts

The forecasts of non-coincident maximum demand at the terminal station level are shown in Table 3 and, graphically, in Figure 5 (50 POE) and Figure 6 (10 POE).

As is shown, the projection is that demand growth at the terminal station level will be quite flat. Averaged across all terminal stations the projected growth rate is 1.53 per cent per annum (at the 50 POE level

Table 3 **Terminal station non-coincident maximum demand forecasts, summer 2014-15 to 2023-24**

Terminal station	POE	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	CAGR
	%	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%
BLTS22	10	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	0.00%
	50	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	0.00%
	90	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	0.00%
BLTS66	10	128.7	127.5	127.5	126.3	124.9	124.0	122.8	121.2	120.4	118.9	-0.88%
	50	120.6	119.0	118.9	117.4	115.8	114.6	113.1	111.8	110.4	108.4	-1.18%
	90	113.8	112.0	112.1	110.2	109.3	107.6	105.9	104.4	103.4	100.9	-1.32%
BTS	10	54.5	55.7	58.1	60.7	62.6	64.1	65.5	66.1	67.1	67.8	2.45%
	50	48.9	49.8	52.0	54.3	55.9	57.2	58.3	58.8	59.3	59.6	2.22%
	90	43.8	44.5	46.5	48.4	50.2	51.0	51.8	52.0	52.5	52.3	1.99%
KTS East[a]	10	247.8	252.8	260.3	265.7	270.8	277.1	282.8	287.8	295.2	300.7	2.17%
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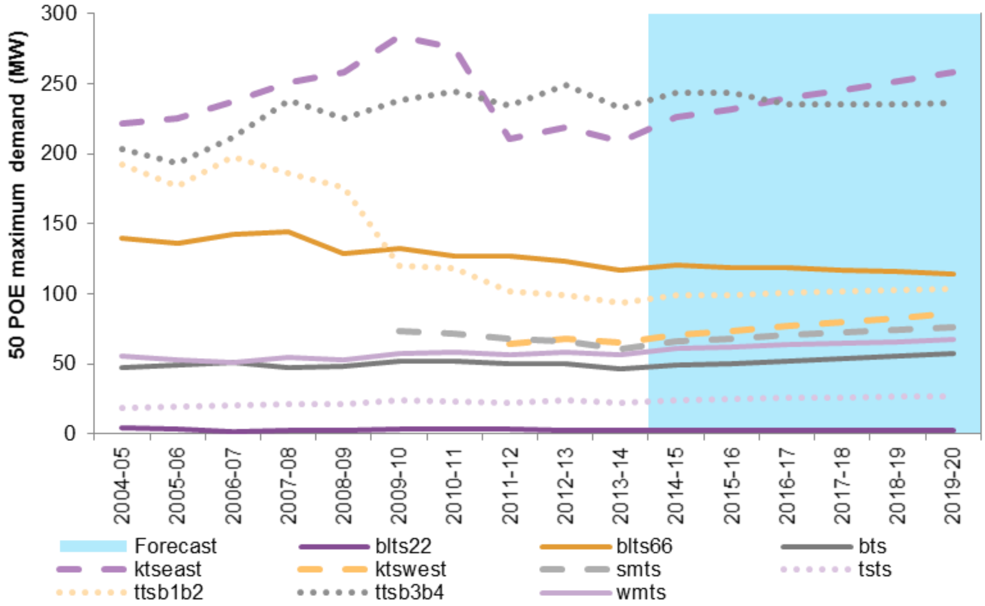
	90	63.3	65.7	69.2	71.7	75.1	78.0	81.1	84.5	88.5	91.5	4.17%
SMTS	10	69.4	71.5	74.4	76.6	78.8	81.4	83.8	86.0	88.9	91.3	3.10%
	50	65.8	67.6	70.4	72.4	74.4	76.7	78.8	81.2	83.5	85.4	2.94%
	90	63.1	64.8	67.6	69.3	71.6	73.5	75.5	77.6	80.1	81.6	2.90%
TSTS	10	27.3	27.9	28.8	29.5	30.1	30.9	31.6	32.3	33.2	33.9	2.44%
	50	24.2	24.7	25.5	26.1	26.6	27.2	27.8	28.5	29.1	29.6	2.25%
	90	21.5	21.9	22.6	22.9	23.4	23.8	24.2	24.6	25.2	25.4	1.86%
TTSB1B2	10	107.0	107.8	109.6	110.5	111.3	112.6	113.5	114.2	115.8	116.6	0.96%
	50	99.0	99.5	101.2	101.8	102.4	103.4	104.1	105.1	105.9	106.3	0.79%
	90	92.4	92.7	94.6	94.8	95.9	96.4	96.9	97.6	98.8	98.7	0.74%
TTSB3B4	10	264.1	265.4	258.3	259.7	260.7	262.8	264.3	265.1	267.8	268.9	0.20%
	50	243.5	243.4	235.5	235.6	235.7	236.6	236.9	237.8	238.3	237.8	-0.26%
	90	230.2	229.5	221.5	220.4	221.4	220.9	220.5	220.4	221.4	219.4	-0.53%
WMTS	10	66.9	68.3	70.3	71.8	73.2	75.0	76.5	78.0	80.0	81.5	2.22%
	50	60.8	61.8	63.6	64.7	65.8	67.2	68.5	69.9	71.2	72.3	1.94%
	90	54.9	55.5	57.0	57.6	58.7	59.4	60.2	61.1	62.3	62.7	1.48%

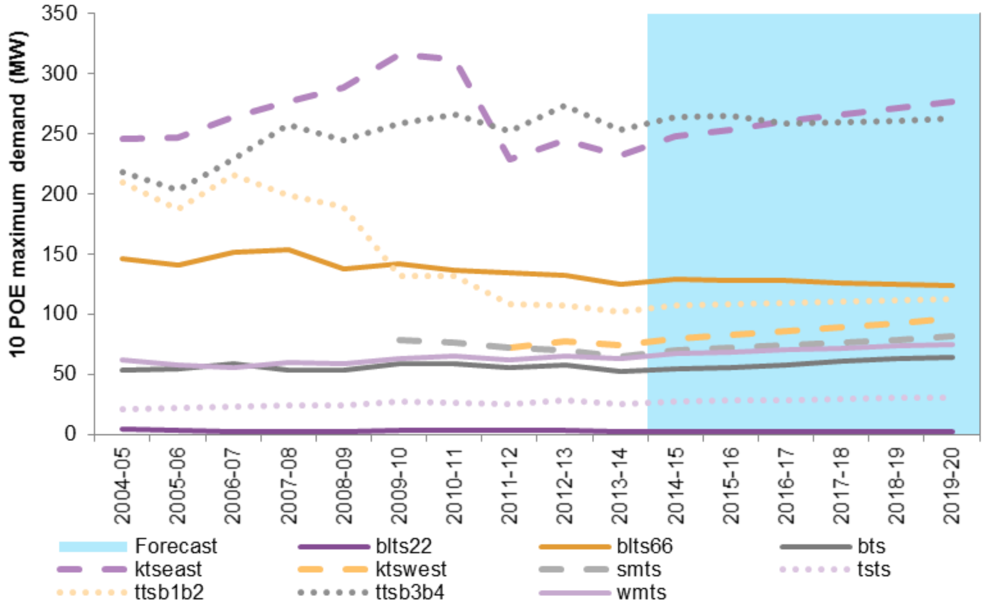
Source: ACIL Allen Consulting

Figure 5 **Terminal station non-coincident maximum demand 50 POE fitted and forecast data, summer 2004-05 to 2019-20**



Source: ACIL Allen Consulting

Figure 6 **Terminal station non-coincident maximum demand 10 POE fitted and forecast data, summer 2004-05 to 2019-20**



Source: ACIL Allen Consulting

2.1.3 Terminal station coincident summer maximum demand forecasts

The forecasts of coincident maximum demand at the terminal station level are shown in Table 4.

As with the non-coincident forecasts the projection is that demand growth at the terminal station level will be quite flat.

Table 4 **Terminal station coincident maximum demand forecasts, summer 2014-15 to 2023-24**

Terminal station	POE	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	CAGR
	%	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%
BLTS22	10	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	0.00%
	50	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	0.00%
	90	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	0.00%
BLTS66	10	120.4	119.3	119.2	118.1	116.9	116.0	114.8	113.3	112.6	111.2	-0.88%
	50	112.8	111.3	111.2	109.8	108.3	107.2	105.8	104.6	103.2	101.4	-1.18%
	90	106.4	104.8	104.9	103.1	102.2	100.6	99.1	97.7	96.7	94.4	-1.32%
BTS	10	52.5	53.7	56.0	58.5	60.3	61.8	63.1	63.7	64.7	65.3	2.45%
	50	47.1	48.0	50.1	52.3	53.9	55.1	56.1	56.7	57.2	57.4	2.22%
	90	42.2	42.8	44.8	46.7	48.4	49.1	49.9	50.1	50.6	50.4	1.99%
KTS East	10	247.3	252.2	259.7	265.1	270.2	276.5	282.2	287.2	294.5	300.1	2.17%
	50	225.9	231.1	239.5	245.3	251.0	257.8	264.1	271.1	277.9	283.5	2.56%
	90	207.0	212.2	221.2	226.4	233.9	239.9	246.1	252.9	261.0	265.7	2.82%
KTS West	10	72.5	75.1	78.6	81.5	84.5	87.9	91.2	94.4	98.5	102.1	3.87%
	50	64.6	66.9	70.3	72.9	75.6	78.8	81.9	85.3	88.8	92.0	4.01%
	90	57.7	59.8	63.1	65.3	68.4	71.1	73.9	77.0	80.6	83.3	4.17%
SMTS	10	65.7	67.7	70.4	72.6	74.7	77.1	79.4	81.5	84.2	86.5	3.10%
	50	62.3	64.0	66.7	68.5	70.4	72.6	74.6	76.8	79.0	80.9	2.94%
	90	59.8	61.4	64.0	65.6	67.8	69.6	71.5	73.5	75.9	77.3	2.90%
TSTS	10	26.3	26.9	27.8	28.4	29.0	29.8	30.5	31.1	32.0	32.7	2.44%
	50	23.4	23.8	24.6	25.1	25.6	26.3	26.8	27.5	28.1	28.6	2.25%
	90	20.8	21.1	21.7	22.0	22.5	22.9	23.3	23.7	24.3	24.5	1.86%
TTSB1B2	10	104.4	105.1	106.9	107.8	108.6	109.8	110.7	111.4	112.9	113.7	0.96%
	50	96.6	97.0	98.8	99.3	99.9	100.9	101.6	102.5	103.3	103.7	0.79%
	90	90.1	90.4	92.2	92.4	93.5	94.0	94.5	95.2	96.4	96.3	0.74%
TTSB3B4	10	263.1	264.4	257.3	258.7	259.7	261.9	263.3	264.1	266.8	267.9	0.20%
	50	242.5	242.5	234.6	234.7	234.8	235.7	236.0	236.9	237.5	236.9	-0.26%
	90	229.4	228.7	220.6	219.5	220.6	220.1	219.7	219.6	220.6	218.6	-0.53%
WMTS	10	65.9	67.2	69.2	70.7	72.1	73.8	75.3	76.7	78.7	80.2	2.22%
	50	59.8	60.8	62.6	63.7	64.8	66.2	67.4	68.8	70.1	71.1	1.94%
	90	54.0	54.6	56.1	56.7	57.8	58.5	59.2	60.1	61.3	61.7	1.48%

Source: ACIL Allen Consulting

2.2 Winter forecasts

This section presents forecasts of maximum demand for each winter from 2014 to 2023:

- section 2.2.1 provides forecasts of maximum winter demand at the system level
- section 2.2.2 provides forecasts of non-coincident maximum winter demand at the terminal station level

— section 2.2.3 provides forecasts of coincident maximum winter demand at the terminal station level.

2.2.1 System maximum demand forecasts

The forecasts of maximum winter demand at the system level are shown in Table 5.

Table 5 **System maximum demand forecasts, winter 2014 to 2023**

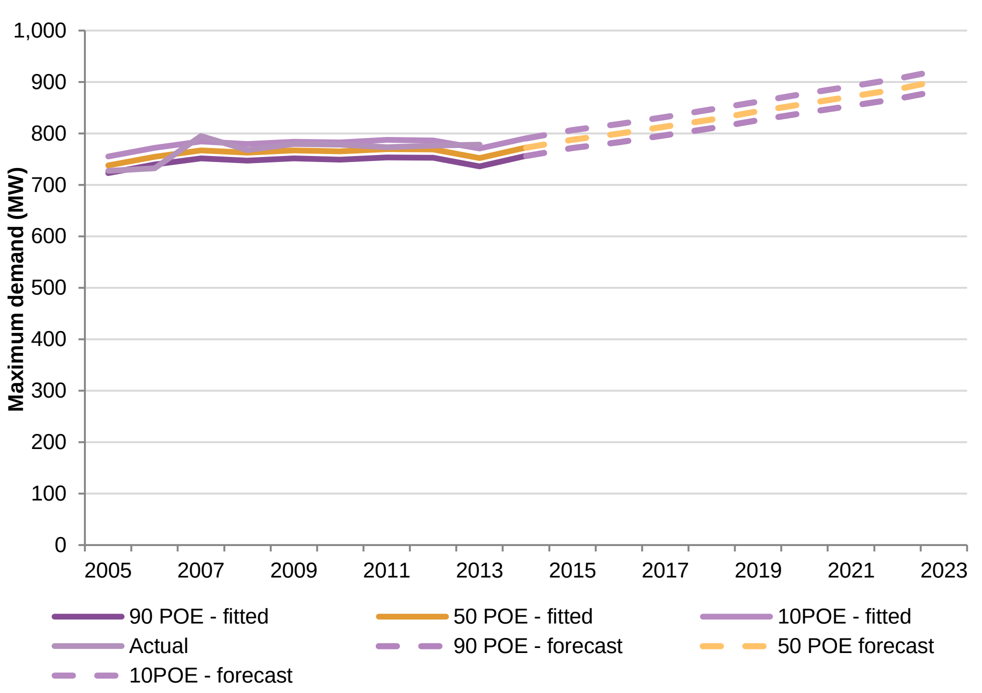
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	CAGR
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%
10 POE	790.8	806.5	818.3	832.3	846.8	862.0	877.5	891.8	906.9	925.0	1.76
50 POE	772.8	788.3	799.9	813.5	827.5	843.4	857.9	872.1	886.2	904.7	1.77
90 POE	756.6	771.9	783.0	796.7	810.4	825.9	840.1	854.1	867.8	885.0	1.76

Source: ACIL Allen Consulting

Figure 7shows the forecasts from Table 5 in graphical form. To place these in context it also shows historical, system level maximum winter demand both actual and weather normalised.

As Table 5 and Figure 7 show, maximum demand is forecast to increase throughout the forecast period at all POE levels. This is largely driven by a return to trend GDP growth, as well as a stabilisation of electricity prices over the period. At the 50 POE level the projection is for annual growth of 1.78 per cent. Winter MD growth is forecast to outstrip summer MD growth due largely to the impact of solar PV systems. Uptake of solar PV systems is forecast to continue growing (see chapter 6) but the forecast impact is constrained to summer because winter MD in JEN's region occurs either too early or too late in the day for solar PV to have a significant impact.

Figure 7 **JEN system level maximum winter demand – actual and forecast**



Source: ACIL Allen Consulting

2.2.2 Terminal station non-coincident winter maximum demand forecasts

The forecasts of non-coincident maximum demand at the terminal station level are shown in Table 6 and, graphically, in Figure 8 (50 POE) and Figure 9 (10 POE).

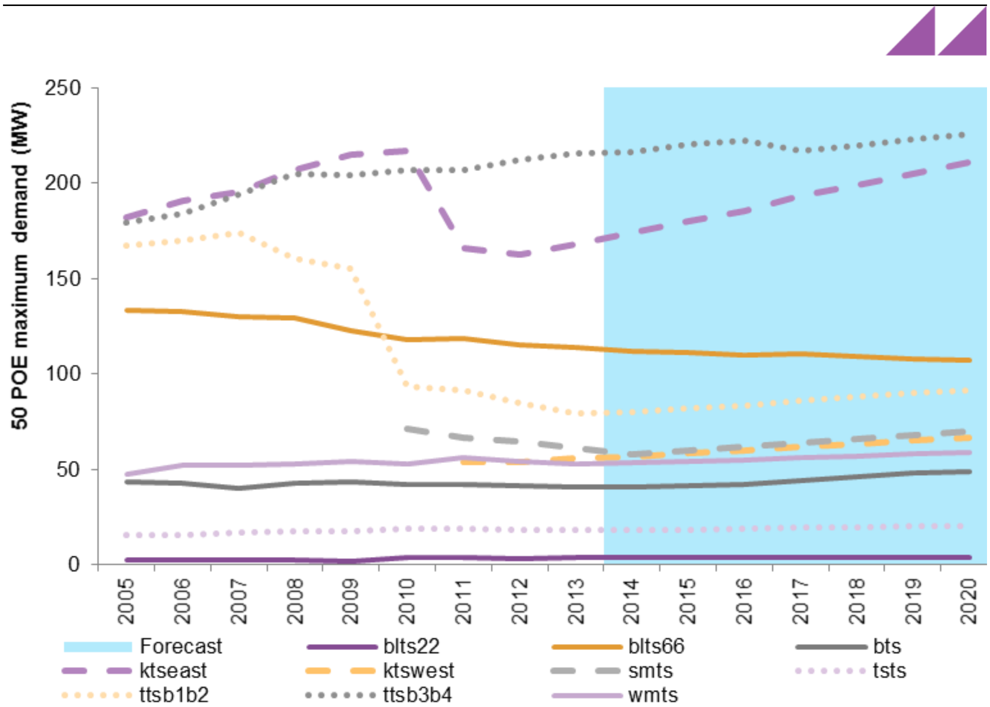
As is shown, the projection is that demand growth at the terminal station level will be quite flat. Averaged across all terminal stations the projected growth rate is 1.73 per cent per annum (at the 50 POE level).

Table 6 **Terminal station non-coincident maximum demand forecasts, winter 2014 to 2023**

Terminal station	POE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	CAGR
	%	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%
BLTS22	10	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	0.00%
	50	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	0.00%
	90	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	0.00%
BLTS66	10	114.3	113.7	112.5	112.8	111.7	110.6	109.6	108.5	107.4	106.6	-0.77%
	50	111.9	111.3	110.1	110.4	109.2	108.2	107.2	106.0	104.8	104.1	-0.80%
	90	109.9	109.3	107.9	108.3	107.0	106.1	104.9	103.7	102.5	101.7	-0.85%
BTS	10	42.2	42.7	43.5	45.6	47.7	49.4	50.4	51.4	51.8	52.4	2.42%
	50	41.0	41.4	42.2	44.3	46.5	48.1	49.1	50.1	50.5	51.1	2.47%
	90	39.9	40.3	41.1	43.2	45.3	47.0	47.9	48.9	49.2	49.8	2.49%
KTS East	10	177.6	183.7	188.8	196.8	202.4	208.4	214.5	220.5	226.8	233.9	3.10%
	50	173.9	180.1	185.3	193.3	198.9	205.1	211.2	217.2	223.4	230.8	3.19%
	90	170.4	176.6	181.7	189.9	195.5	201.8	207.8	213.9	220.1	227.2	3.25%
KTS West	10	58.3	60.0	61.4	63.7	65.2	66.8	68.5	70.1	71.9	73.8	2.65%
	50	56.8	58.5	59.9	62.2	63.7	65.3	67.0	68.6	70.2	72.3	2.71%
	90	55.5	57.2	58.5	60.8	62.3	63.9	65.6	67.2	68.8	70.7	2.73%
SMTS	10	59.9	61.7	63.2	65.8	67.5	69.3	71.3	73.2	75.2	77.5	2.91%
	50	58.2	60.1	61.7	64.3	66.0	68.0	69.9	71.9	73.9	76.4	3.05%
	90	57.0	59.0	60.6	63.2	65.1	67.1	69.1	71.2	73.3	75.8	3.21%
TSTS	10	18.8	19.3	19.6	20.2	20.5	20.9	21.3	21.6	22.0	22.5	1.99%
	50	18.3	18.7	19.0	19.6	19.9	20.3	20.6	21.0	21.3	21.8	1.97%
	90	17.8	18.2	18.5	19.1	19.4	19.7	20.1	20.4	20.8	21.2	1.93%
TTSB1B2	10	82.1	84.1	85.6	88.4	90.1	91.9	93.9	95.7	97.6	99.9	2.21%
	50	80.3	82.2	83.7	86.5	88.1	90.0	91.8	93.5	95.3	97.6	2.20%
	90	78.6	80.5	81.9	84.7	86.2	88.0	89.8	91.5	93.2	95.4	2.16%
TTSB3B4	10	221.0	224.7	227.2	222.4	225.2	228.2	231.5	234.5	237.8	241.8	1.00%
	50	216.6	220.1	222.4	217.3	219.8	223.0	225.8	228.6	231.5	235.5	0.93%
	90	212.5	215.9	217.8	212.7	215.0	217.8	220.5	223.1	225.7	229.2	0.84%
WMTS	10	55.2	56.2	56.9	58.5	59.3	60.1	61.1	61.9	62.9	64.0	1.65%
	50	53.4	54.3	55.0	56.4	57.1	58.0	58.8	59.6	60.4	61.5	1.59%
	90	51.7	52.6	53.2	54.6	55.3	56.1	56.8	57.6	58.3	59.3	1.52%

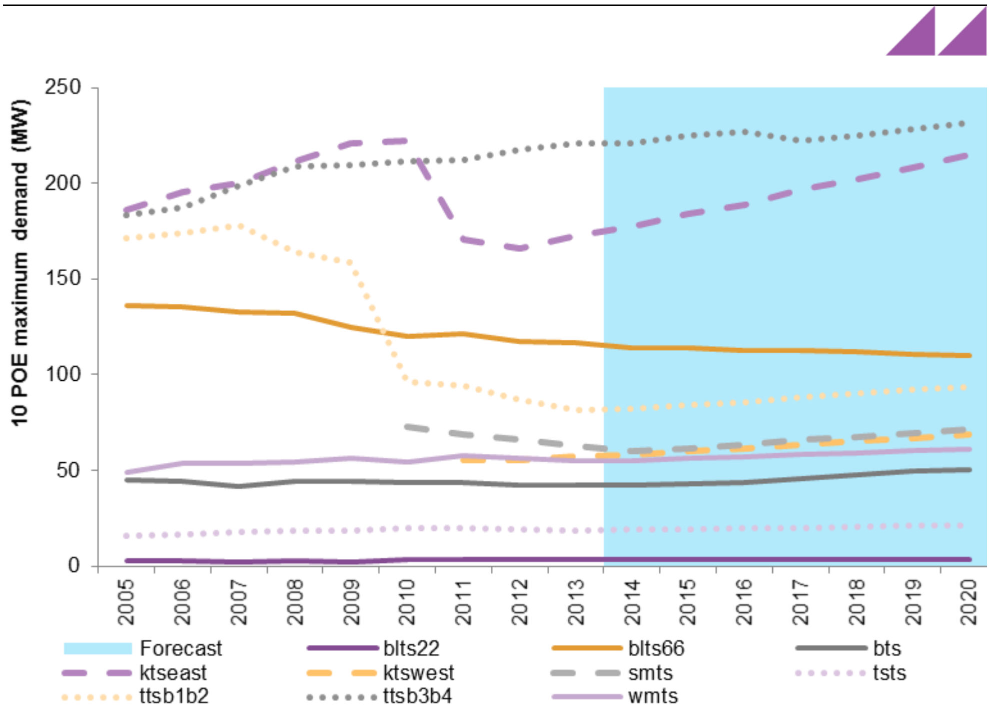
Source: ACIL Allen Consulting

Figure 8 **Terminal station non-coincident maximum demand 50 POE fitted and forecast data, winter 2005 to 2020**



Source: ACIL Allen Consulting

Figure 9 **Terminal station non-coincident maximum demand 10 POE fitted and forecast data, winter 2005 to 2020**



Source: ACIL Allen Consulting

2.2.3 Terminal station coincident winter maximum demand forecasts

The forecasts of coincident maximum demand at the terminal station level are shown in Table 7.

As with the non-coincident forecasts the projection is that demand growth at the terminal station level will be quite flat.

Table 7 **Terminal station coincident maximum demand forecasts, winter 2014 to 2023**

Terminal station	POE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	CAGR
	%	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%
BLTS22	10	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	0.00%
	50	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	0.00%
	90	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	0.00%
BLTS66	10	111.0	110.4	109.2	109.5	108.4	107.4	106.5	105.3	104.3	103.5	-0.77%
	50	108.7	108.1	106.9	107.2	106.0	105.1	104.1	102.9	101.8	101.1	-0.80%
	90	106.7	106.1	104.8	105.1	103.9	103.0	101.9	100.7	99.6	98.7	-0.85%
BTS	10	38.1	38.5	39.3	41.1	43.1	44.6	45.5	46.4	46.8	47.3	2.42%
	50	37.0	37.4	38.1	40.0	42.0	43.5	44.4	45.3	45.6	46.1	2.47%
	90	36.0	36.4	37.1	39.0	40.9	42.4	43.3	44.2	44.5	45.0	2.49%
KTS East[a]	10	175.4	181.4	186.4	194.3	199.9	205.7	211.8	217.7	223.9	230.9	3.10%
	50	171.7	177.8	182.9	190.9	196.4	202.5	208.5	214.5	220.6	227.9	3.19%
	90	168.2	174.3	179.4	187.5	193.1	199.2	205.2	211.2	217.3	224.3	3.25%
KTS West	10	37.8	38.9	39.8	41.3	42.3	43.3	44.4	45.5	46.6	47.9	2.65%
	50	36.8	37.9	38.8	40.3	41.3	42.4	43.4	44.5	45.5	46.9	2.71%
	90	36.0	37.1	37.9	39.4	40.4	41.5	42.5	43.6	44.6	45.9	2.73%
SMTS	10	58.2	60.0	61.4	63.9	65.6	67.4	69.2	71.1	73.1	75.3	2.91%
	50	56.6	58.4	59.9	62.4	64.1	66.0	67.9	69.8	71.8	74.2	3.05%
	90	55.4	57.3	58.9	61.4	63.2	65.2	67.2	69.2	71.2	73.6	3.21%
TSTS	10	17.3	17.7	18.0	18.5	18.8	19.2	19.5	19.9	20.2	20.7	1.99%
	50	16.8	17.2	17.4	18.0	18.3	18.6	18.9	19.3	19.6	20.0	1.97%
	90	16.4	16.7	17.0	17.5	17.8	18.1	18.4	18.8	19.1	19.5	1.93%
TTSB1B2	10	81.7	83.7	85.2	88.0	89.7	91.6	93.5	95.3	97.2	99.5	2.21%
	50	80.0	81.9	83.4	86.1	87.7	89.6	91.4	93.1	94.9	97.2	2.20%
	90	78.3	80.2	81.6	84.3	85.9	87.7	89.4	91.1	92.9	95.0	2.16%
TTSB3B4	10	220.8	224.5	227.0	222.2	225.0	228.1	231.3	234.3	237.6	241.6	1.00%
	50	216.4	219.9	222.2	217.2	219.7	222.8	225.7	228.5	231.3	235.3	0.93%
	90	212.3	215.7	217.7	212.5	214.8	217.7	220.3	222.9	225.5	229.0	0.84%
WMTS	10	49.2	50.1	50.7	52.1	52.8	53.6	54.4	55.2	56.0	57.0	1.65%
	50	47.6	48.4	49.0	50.3	50.9	51.7	52.4	53.1	53.8	54.8	1.59%
	90	46.1	46.9	47.4	48.6	49.2	49.9	50.6	51.3	51.9	52.8	1.52%

Source: ACIL Allen Consulting

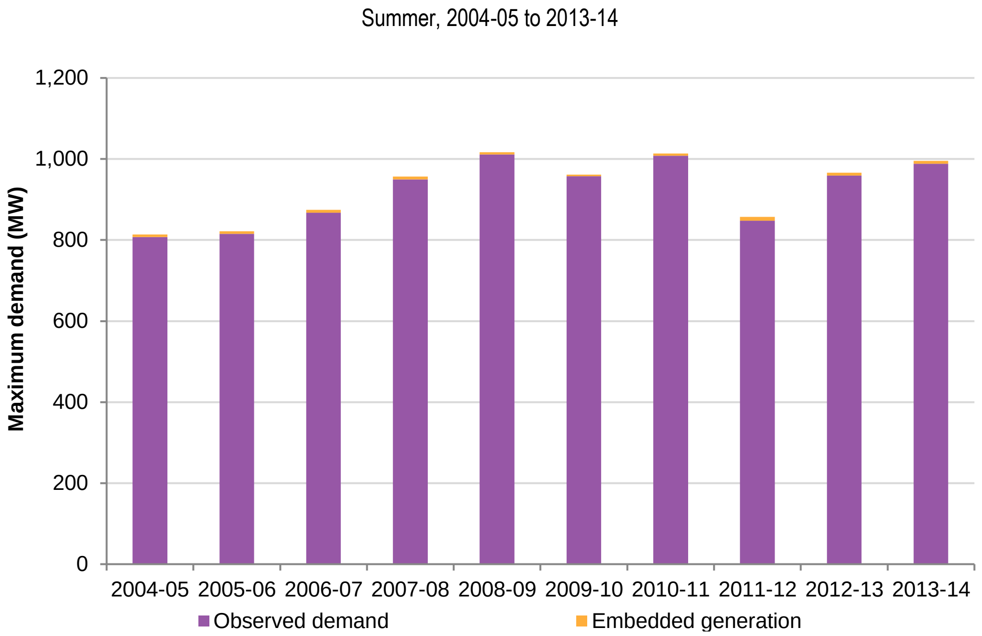
3 Historical demand data

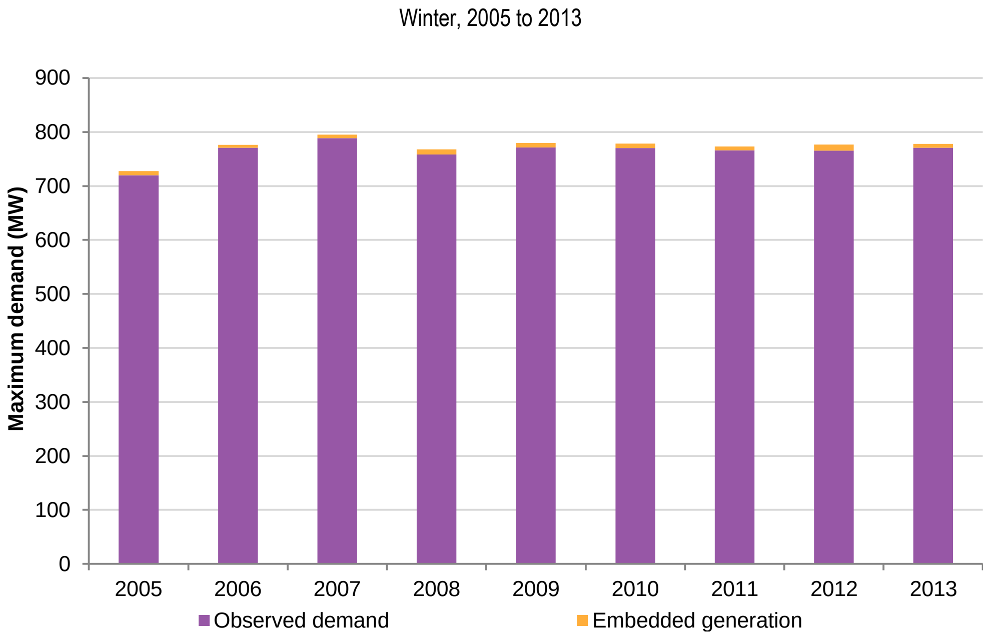
This chapter provides an overview of historical electricity demand in JEN's region. These data are the basis of the regression models in chapter 5.

Figure 10 shows maximum demand at the system level for summer (from 2004-05 to 2013-14) and winter (2005 to 2013). Generation is a relatively minor adjustment to observed demand, never contributing more than 11 MW at a time of maximum demand. Maximum demand in summer appears to exhibit a broad upward trend. In contrast, in winter it appears to be relatively steady.

The maximum demand levels considered in the forecasting process are temperature corrected. The maximum demand levels shown in Figure 10 are not temperature corrected.

Figure 10 **System latent maximum demand by component**





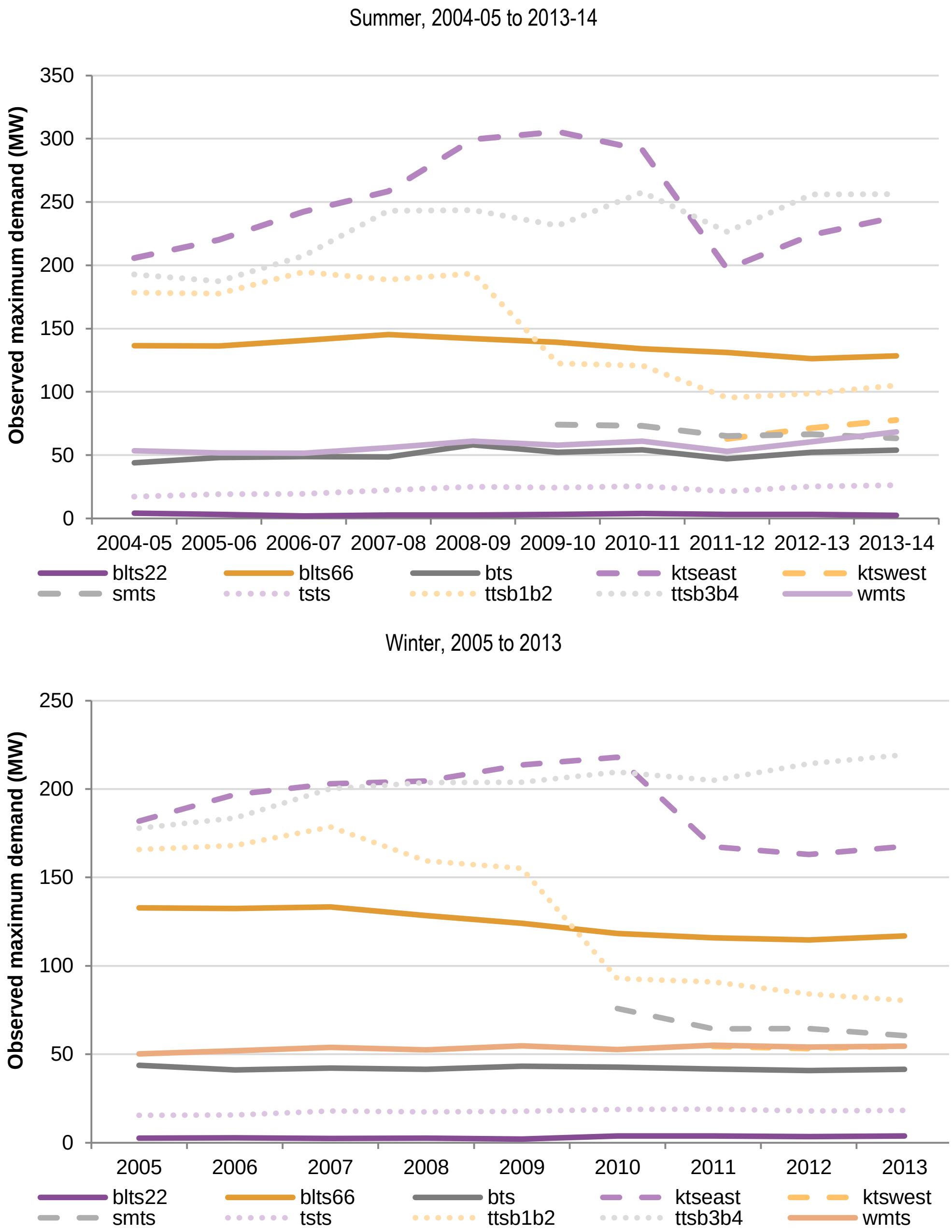
Note: Rooftop photovoltaic generation also contributes to latent demand, but is considered as an input variable in maximum demand forecasts, rather than as part of the dependent variable.

Source: ACIL Allen consulting analysis of JEN data

3.1 Terminal station demand

Figure 11 shows non-coincident maximum demand by terminal station, for summer (from 2004-05 to 2013-14) and winter (2005 to 2013). These are net of the impact of embedded generation, rooftop PV, and load transfers. Growth has been flat at most terminal stations, though this is obscured by the effect of weather and several transfers between terminal stations, in particular the commissioning of the South Morang Terminal station in 2010.

Figure 11 **Non-coincident observed maximum demand**

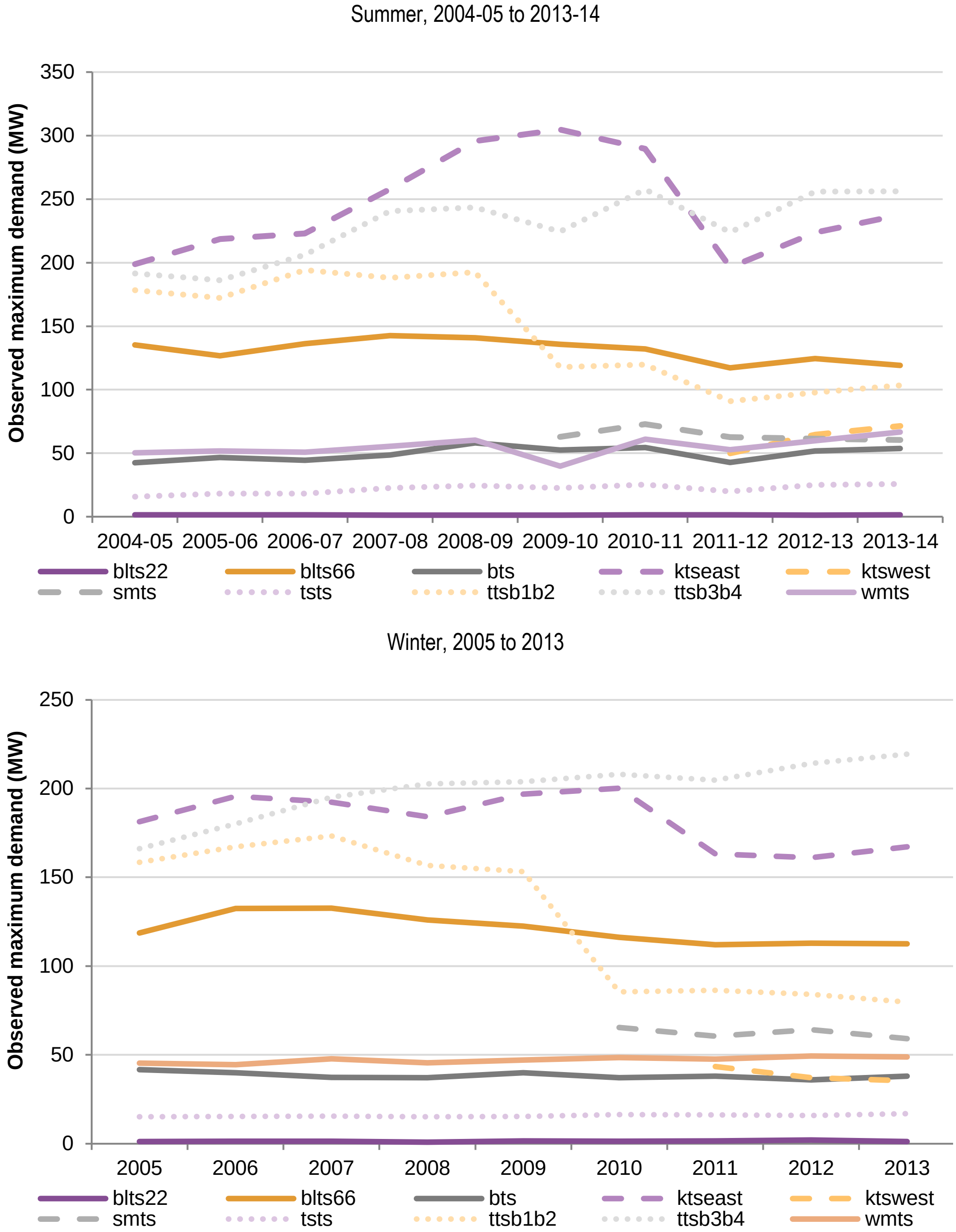


Note: Rooftop photovoltaic generation, other embedded generation, and load transfers, also contribute to latent demand, but are not shown here

Source: ACIL Allen consulting analysis of JEN data

Figure 12 shows coincident maximum demand by terminal station over the same period. Once again, these are net of the impact of embedded generation, rooftop PV, and load transfers.

Figure 12 **Coincident observed maximum demand**



Note: Rooftop photovoltaic generation, other embedded generation, and load transfers, also contribute to latent demand, but are not shown here

Source: ACIL Allen consulting analysis of JEN data

4 Drivers of demand

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

- economic activity - section 4.1
- photovoltaic (PV) generation capacity - in section 4.2
- electricity prices - section 4.3
- weather - in section 4.4.

The historical data series presented in these sections were used as the explanatory variables in the regression models described in chapter 5. The projections of drivers presented in this chapter were used as inputs into the maximum demand forecasts.

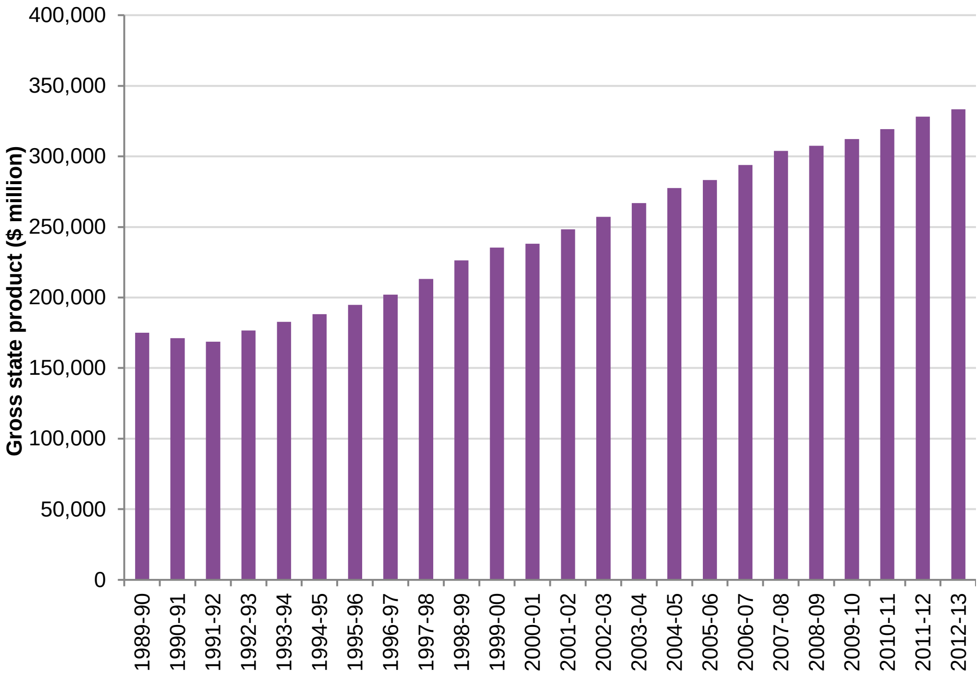
4.1 Economic activity

Growth in economic activity is a major driver of rising incomes. Demand for electricity is, in part, driven by the ownership of appliances that can be used in peak demand conditions. Two important examples are air-conditioners, and electric space heating. Economic activity is likely to interact with temperature in its impact on maximum demand.

Figure 13 shows the historical time series of Victorian economic activity, as measured by Gross State Product (GSP), from 1989-90 to 2012-13.[3]

[3] 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 13 **Victorian Gross State Product (GSP), 1989-90 to 2012-13, $m (chain volume measure)**



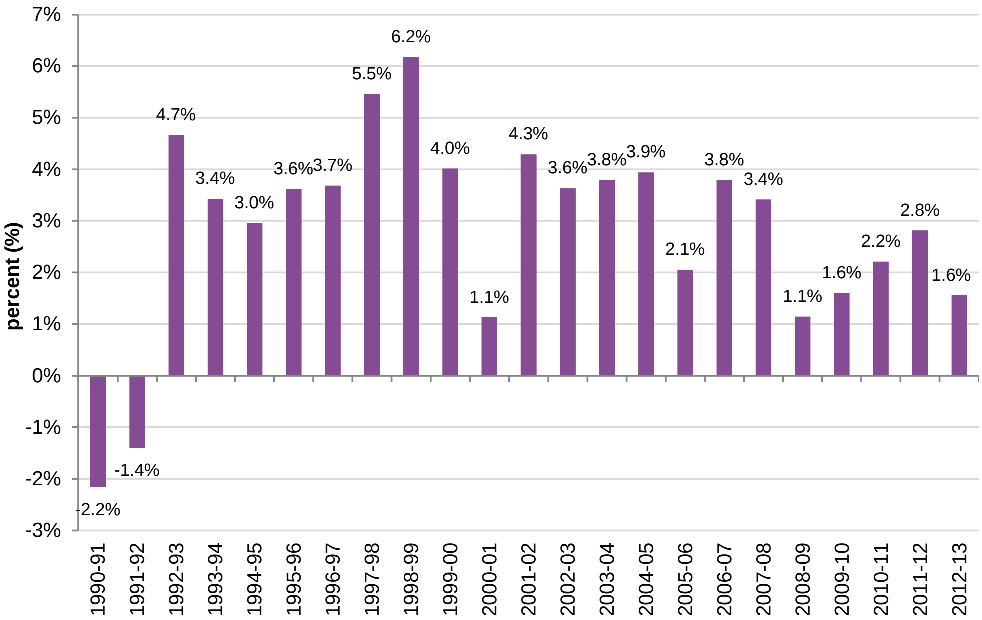
Note: GSP figures are for financial years. This was mapped to calendar years by taking an average of the appropriate financial years for each calendar year.

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 14).

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 14 **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 model developed for JEN. They are summarised in Table 8.

Table 8 **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%
AEMO 2014 National Electricity Forecasting Report	2.47%	3.57%	4.39%	4.59%
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:

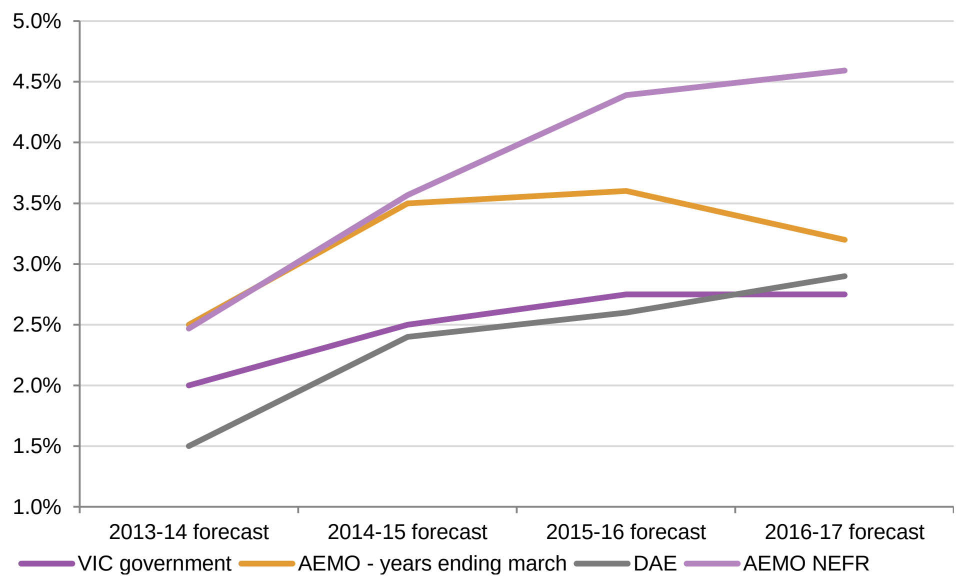
[a] *Economic outlook information paper*, Australian Energy Market Operator, 2013, page 5-24

[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 15 shows how forecasts from the Victorian Government, the Australian Energy Market Operator, and Deloitte Access Economics compare. The Victorian Government forecasts are towards the centre of the available forecasts so they were selected as the basis of GSP forecasts used in the consumption model.

Figure 15 **Victorian GSP growth forecasts, 2013-14 to 2016-17**



Sources:

Victorian government, budget outlook 2014

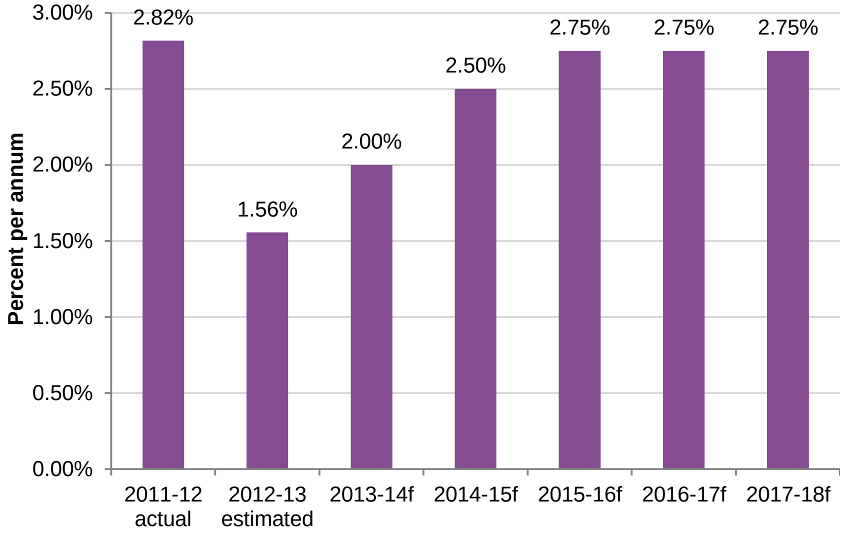
Economic outlook information paper, Australian Energy Market Operator, 2013

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



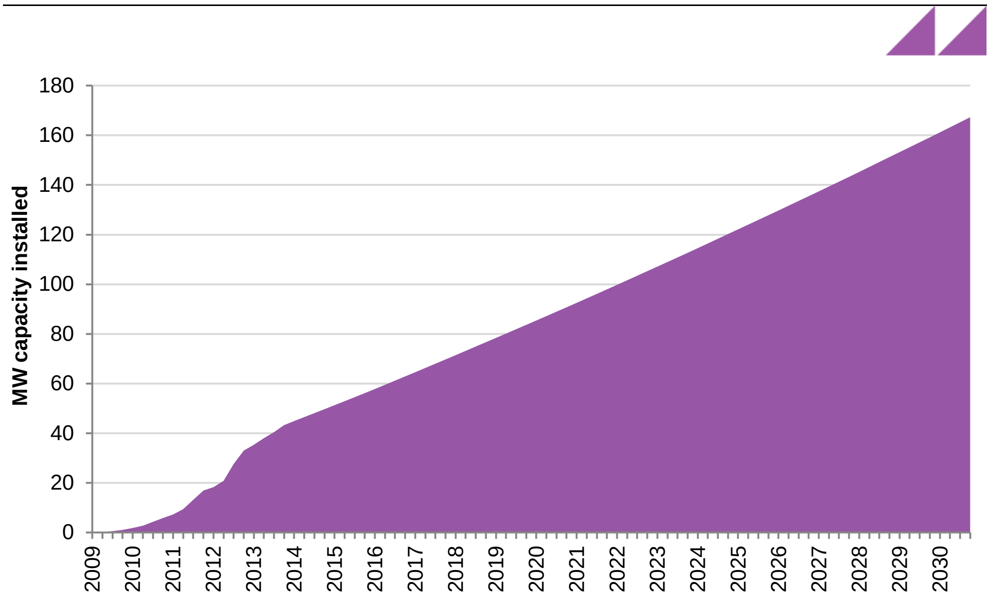
Source: Victorian Government, "Strategy and Outlook 2013-14"

4.2 PV generation capacity

The take-up and usage of rooftop PV systems has a negative impact on demand at the terminal station level. This is because energy generated from these systems is used to offset demand from the owner of the system. Excess energy generated from these systems is also exported to other households within JEN's distribution region without passing through a terminal station. Hence all generation from PV systems can be considered to offset demand. This is in contrast to measures of consumption, where the relevant measurement occurs at individual household meters.

Increased uptake of rooftop PV is a relatively recent phenomenon. Changes in the uptake level of rooftop PV can be attributed to the range of financial incentives households have been offered to install such systems from 2009 onwards. The model described in chapter 6 forecasts rooftop PV capacity into the forecast period, based on a set of assumptions around the financial incentives that are likely to apply. Figure 17 shows the cumulative level of PV capacity projected using this model.

Figure 17 **Cumulative capacity of installed solar PV systems**



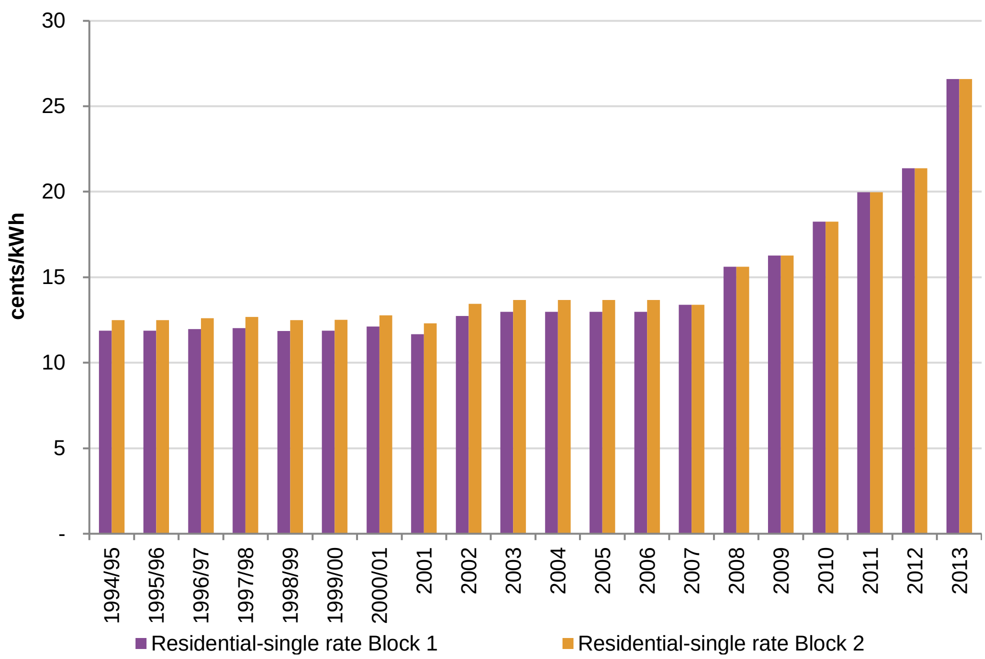
Source: ACIL Allen Consulting

4.3 Electricity prices

Another likely driver of demand is the price of electricity. Higher electricity prices would be expected to decrease maximum demand by creating incentives for customers to become more energy efficient (through appliances and housing design).

Figure 18 shows a time series for electricity prices for the residential tariffs from 1995 to 2013. Tariffs were relatively stable until 2007, 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 demand.

Figure 18 **Residential single rate tariff- Block 1 and 2**



Data source: Essential Services Commission

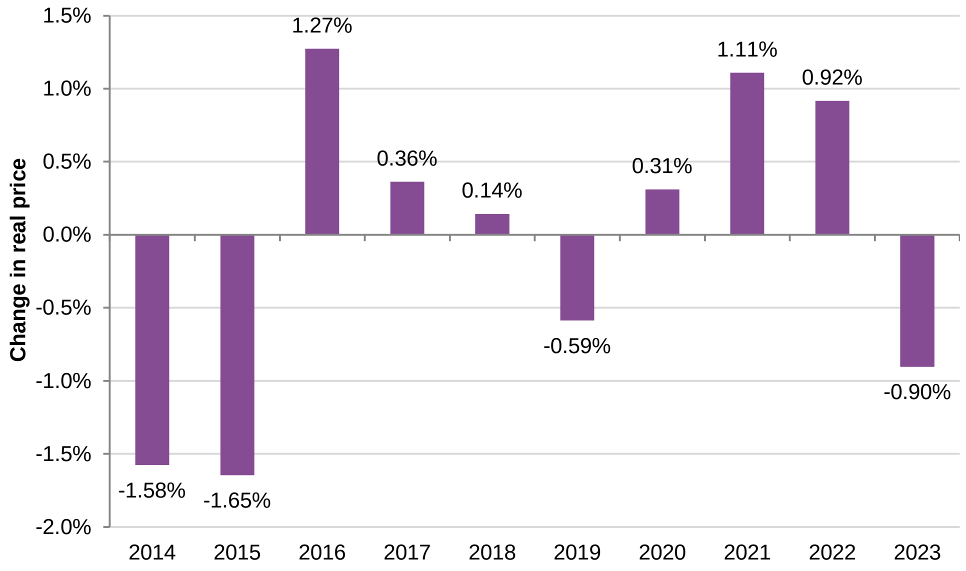
Forecast electricity price changes

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 are impacted by carbon pricing. Forecasts of these costs were generated using ACIL Allen's proprietary *Powermark* model, assuming the carbon tax is repealed in 2015
- **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 19.

Figure 19 **Forecast change in real electricity prices**



Source: ACIL Allen Consulting

4.4 Weather

The weather is a key driver of demand in both summer and winter.

In winter, demand that varies with weather conditions is driven primarily by the 'heating requirement'. Generally, cooler seasons would be associated with a greater heating requirement, and therefore a greater maximum demand. In summer this pattern is reversed, with cooling becoming the driver of weather-related demand.

The impact of weather is strongly related to the availability of appliances, and hence economic activity. The impact of weather may also change depending on whether the day's conditions are at the end of a warm or cool streak. Forecasts of weather are not used within the maximum demand forecasting. Rather, historical weather conditions since 1970 are used to develop a confidence interval around maximum demand forecasts.

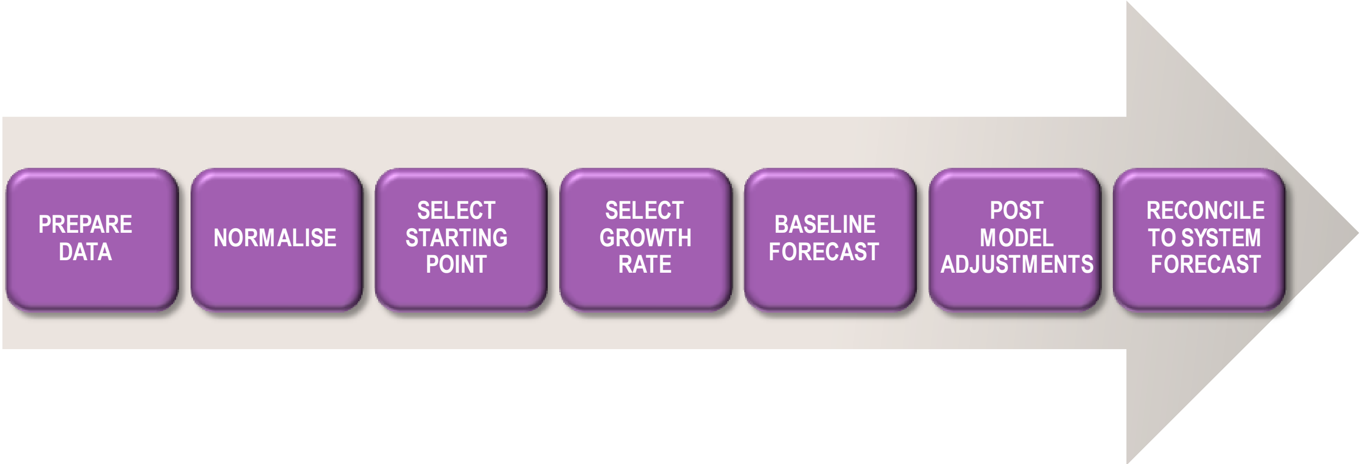
Weather measurements were taken from the Melbourne Airport weather station, as reported to the Bureau of Meteorology website.

5 Methodology

The maximum demand forecasts presented in this report were prepared separately for the system level and for the terminal station level using the methodology ACIL Allen developed for AEMO in 2013.[4] This chapter provides a brief summary of that methodology. More detail is provided in the report to AEMO.

The methodology consists of seven steps as illustrated in Figure 20. This chapter addresses each of the seven steps in turn.

Figure 20 **Forecasting methodology**



5.1 Prepare data

The first step in the methodology is to collect the necessary data and manage it appropriately.

The main dataset required is a time series of high frequency data (15 or 30 minute interval) of demand at each terminal station to be forecast. Ideally this time series should go back for at least 10 years.

These data should be well understood and should relate closely to what is being forecast. Three factors that may require adjustments to the historical data should be considered:

1. network configuration
2. block loads
3. output of embedded generation

JEN provided ACIL Allen with historical data showing demand at each terminal station with 15 minute frequency. The demand data covered the period from 1 June 2000 to 31 March 2014.

JEN also provided data showing the output of embedded generators in the same format, though these were not available before 31 August 2004. This was part way through a winter

[4] see ACIL Allen, "Connection point forecasting - a nationally consistent methodology for forecasting maximum electricity demand", 28 June 2013, available from www.aemo.gov.au

so the data series commenced from 1 November 2004 and ran for approximately nine and a half years until 31 March 2014.

Generation was added to demand at each terminal station to derive latent demand from Summer 2004-05 onwards. These series were used to identify latent daily maximum demand at both the terminal station and system levels. Coincident demands at the terminal stations were also identified.

It should be noted that the forecasts presented here are for latent demand. That is, the projected impact of embedded generators other than solar PV have not been deducted from the forecasts. This is to allow JEN to incorporate its own views regarding the likely future operation of those generators at the distribution feeder level.

The demand dataset was obtained from JEN's internal system and is understood to be an accurate reflection of demand at each terminal station.

Adjustments were made to the historical data to account for changes in network configuration as summarised in Table 9.

Table 9 **Historic block load and transfers - summer**

Terminal station	2009-10	2010-11	2011-12	2012-13	2013-14	Reason
Load transfers						
Keilor East			-63.0			[c-i-c]
South Morang			-7.0	-4.7	-3.7	
Thomastown b1b2	-74.0					
Thomastown b3b4			7.0	4.7		
Major customers						
Brooklyn TS 66kV		-6.20				[c-i-c]
Thomastown b1b2	-6.90					
				-5.10	-4.90	

Source: JEN

Table 10 **Historic block load and transfers - winter**

Terminal station	2009	2010	2011	2012	2013	Reason
Load transfers						
Keilor TS East			-55.0			[c-i-c]
South Morang TS			-7.0		-4.7	
Thomastown TS		-75.0				
Thomastown TS			7.0		4.7	
Major customers						
Brooklyn TS 66kV		-4.70				[c-i-c]
Thomastown b1b2	-7.70					
					-13.20	

Source: JEN

The next dataset to collect is weather data for normalisation. Daily maximum and minimum ambient temperature data were obtained from the Bureau of Meteorology for the Melbourne Airport weather station. It is summarised in Figure 21 below.

5.2 Normalise

The historical demand data were weather normalised using the 'regression and simulation' approach,[5] which comprises four steps:

1. prepare the dataset for normalisation
2. estimate the relationship between temperature and demand at the terminal station
3. create a distribution of maximum demands for each terminal station for each year
4. identify 'normal' maximum demand from that distribution.

The procedure was performed separately for each season and each year

The appropriate dataset to use for normalisation is a subset of the demand data collected at stage 1. Generally, it should:

1. reflect only the season of interest, i.e. summer or winter
2. be one year's data unless conditions were very mild or very extreme
3. be truncated to remove:
   a) demand on 'mild' days
   b) demand on non-working days.

The system level demand data (still including working days) are illustrated in Figure 21.[6]

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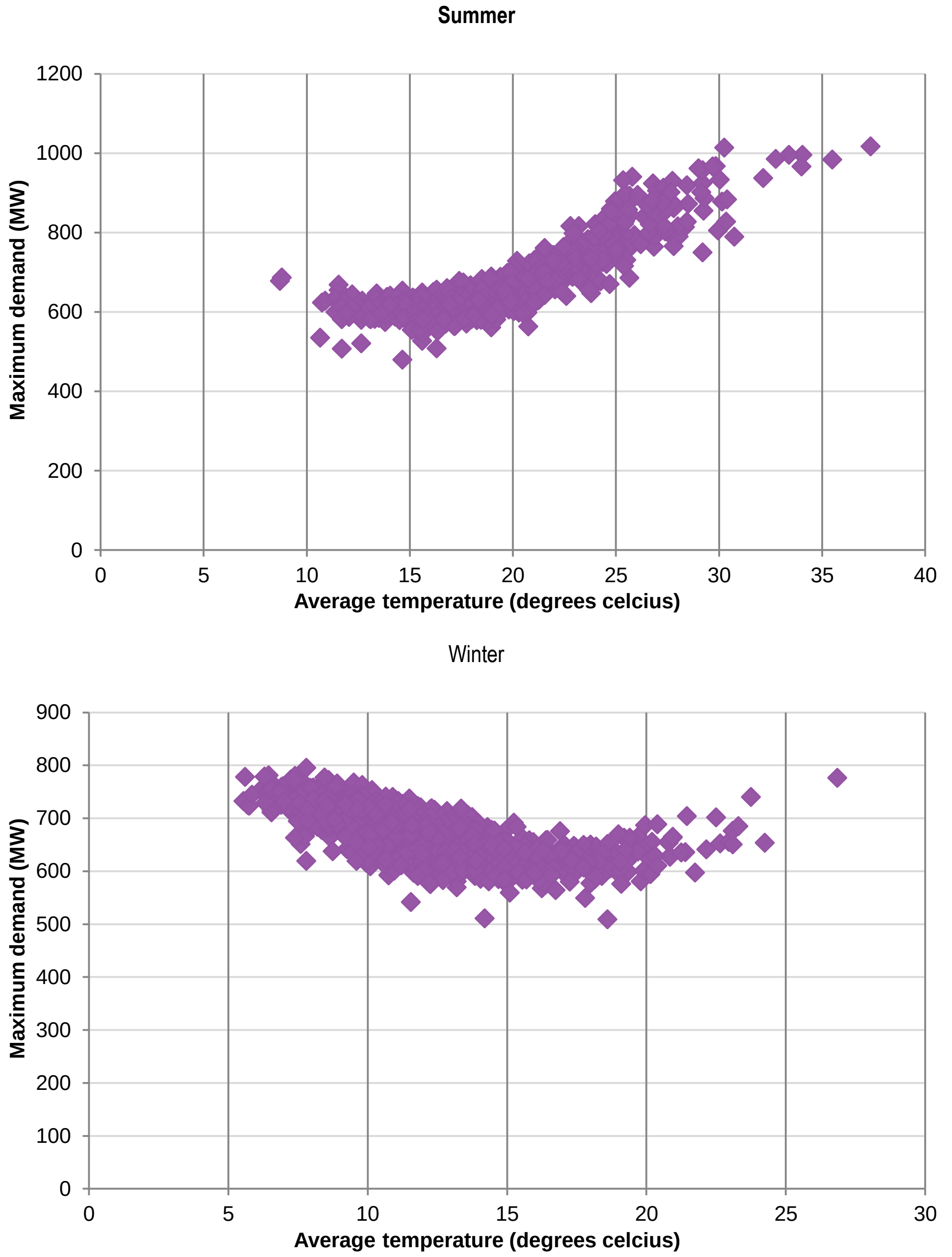
[5] see ACIL Allen's report to AEMO for a more detailed description.

[6] The figure shows demand pooled for all years. The weather normalisation was conducted on a year by year basis separately.

Figure 21 **Maximum demand and average daily temperature – working days, November 2004 to March 2013**



Note: Average daily temperatures calculated as the average of maximum and minimum temperature from the Melbourne Airport weather station
Source: ACIL Allen Consulting

The next step was to estimate a set of models for each terminal station that relate the dataset in Figure 21 (upper pane) to the following explanatory variables:

— Summer
  – **Min$_t$:** minimum daily temperature for the current day
  – **Max$_{t-1}$:** maximum daily temperature for the current day
  – **Max$_{t-1}$:** maximum daily temperature on the previous day
  – **Max$_{t-2}$:** maximum daily temperature on two days prior
  – **February$_t$:** indicator variable, equal to '1' if month is February, '0' otherwise
  – **Monday$_t$:** indicator variable, equal to '1' if day is Monday, '0' otherwise

– **Friday$_t$:** indicator variable, equal to '1' if day is Friday, '0' otherwise

— Winter

– **variables as per above**

This model was fit for each year from 2004-05 to 2013-14. Estimated coefficients for 2013-14 are shown in Table 11 (summer) and Table 12 (winter).

Table 11 **Terminal station maximum demand models (summer), 2013-14 estimated coefficients**

Variable	blts22	blts66	bts	ktseast	ktswest	smts	tsts	ttsb1b2	ttsb3b4	wmts
Constant	1.55**	41.48**	-11.18**	-12.4	-21.68**	33.84**	-7.62**	15.6**	69.58**	-3
Min$_t$		1.31**	1.12**	4.24**	1.89**	0.44**	0.6**	1.49**	2.9**	1.1**
Max$_t$		0.89**	0.48**	2.11**	0.48	0.44**	0.19**	0.76**	2.28**	0.62**
Max$_{t-1}$		0.16	0.03	0	-0.21	-0.04	0.01	0	-0.09	0.02
Max$_{t-2}$		-0.03	0.07	0.36	0.28*	0.06	0.06	0.12	0.11	0.11
February$_t$	-0.06	-0.13	-0.03	0.66	-1.61	0.53	-0.03	0.48	5.48*	-1.24
Monday$_t$	-0.05	-2.48	-1.23	-4.49	-1.84	-1.78**	-0.24	-1.41	-3.6	-1.5
Friday$_t$	0.12*	-1.48	0.98	-0.8	-0.07	-2.36**	0.29	-0.5	-4.82	-0.68

Note: **significant at the 1 per cent level. * significant at the 5 per cent level
Source: ACIL Allen Consulting

Table 12 **Terminal station maximum demand models (winter), 2013 estimated coefficients**

Variable	blts22	blts66	bts	ktseast	ktswest	smts	tsts	ttsb1b2	ttsb3b4	wmts
Constant	1.83**	122.02**	47.41**	189.39**	63.69**	62.99**	20.57**	85.27**	231.85**	56.81**
Min		-0.58**	-0.58**	-1.9**	-0.89**	-0.4**	-0.25**	-0.58**	-1.15**	-0.7**
Max		-0.54**	-0.24**	-0.65**	-0.11	-0.19*	-0.09**	-0.55**	-0.79**	-0.16*
Maxt-1		-0.14	-0.06	-0.17	-0.02	-0.07	-0.02	0.06	-0.48*	-0.1
Maxt-2		-0.32**	-0.06	-0.32*	-0.07	-0.05	-0.02	-0.2**	-0.49**	0.02
April	-0.05	-4.92**	-3.61**	-12.06**	-4.01**	-1.48	-1.17**	-4.03**	-14.45**	-1.04
June	-0.04	2.37**	-0.35	2.38*	0.89*	1.31*	0.35*	1.24*	3.78*	2.94**
September	0.3**	-2.86**	-2.75**	-7.03**	-3.07**	-0.6	-1.48**	-4.03**	-9.87**	-4.26**
October	-0.02	-4.05**	-5.02**	-11.33**	-7.91**	-0.24	-2.5**	-3.92**	-8.32**	-5.63**
Monday	0.01	-1.36*	0.29	-0.59	0.9*	-0.68	0.2	-0.62	-0.98	0.68
Friday	0.17**	-1.27	-0.94**	-1.58	-1.95**	-1.89**	-0.55**	-0.25	-4.55**	-3.07**

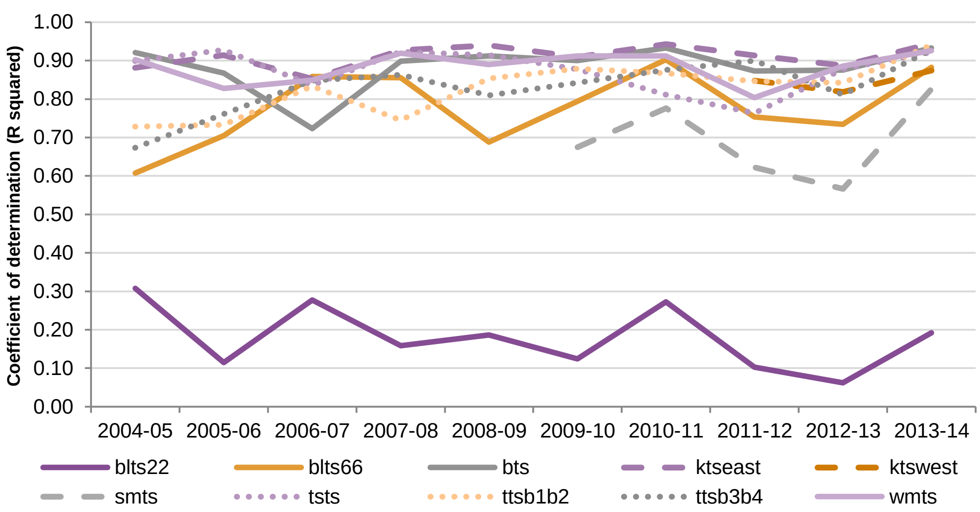
Note: **significant at the 1 per cent level. * significant at the 5 per cent level
Source: ACIL Allen Consulting

The directions of estimated coefficients for 2013-14 are largely consistent with those estimated for the system model (see section 5.8).

One terminal station that exhibited poor fit was BLTS22, which services Melbourne Water only. This terminal station does not display the same relationship between weather and demand as others, which is unsurprising given the load connected to it.

Model fit for all other terminal stations was high enough to justify using these models. Figure 22 shows the coefficient of determination (R^2) for each terminal station in each year.

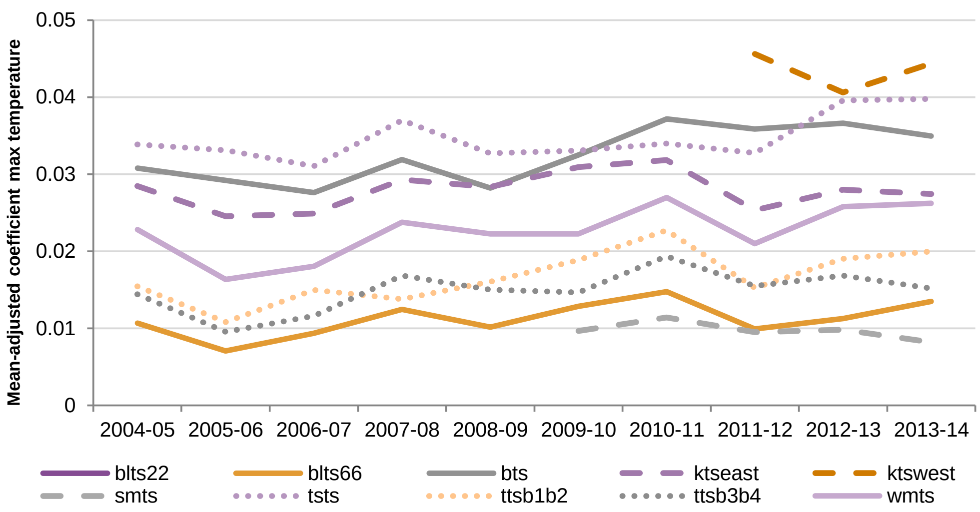
Figure 22 **Coefficient of determination for terminal station models in each year, summer 2004-05 to 2013-14**



Source: ACIL Allen Consulting

Figure 23 shows the estimated coefficients on maximum temperature, adjusted by the average daily maximum demand for each terminal station in each year. Keilor West appears to be the most temperature sensitive terminal station, while South Morang is the least temperature sensitive. The mean-adjusted temperature sensitivities of most terminal stations have been increasing over time.

Figure 23 **Mean-adjusted coefficients on maximum temperature for terminal station models in each year, summer 2004-05 to 2013-14**



Source: ACIL Allen Consulting

5.3 Selecting the starting point

When the historical data have been weather corrected the starting point for the forecasts can be selected. Conceptually, this is the weather normalised demand in the last year for which actual data are available.

Practically, two options are available and a judgement must be made.

The options are to define the starting:

- 'off the point' taking the simulated 50 (or 10 or 90) POE value for the last available year
- 'off the line' taking the value off a regression line fitted to the weather normalised history.

ACIL Allen compared the 'point' with the 'line' at each terminal station for summer and winter. In the summer models, the 'line' was above the point in all cases whereas in the absence of a statistical bias the distribution should be more even. For this reason ACIL Allen chose to take all of the terminal station forecasts off the point.

5.4 Select the initial growth rate

Growth rates are chosen based on the regression developed in choosing the starting point, though again some judgement is required.

Most terminal stations were assumed to grow at the rate exhibited in the weather normalised data over the past seven years, which is the period for which data were available. There were two exceptions.

The Brooklyn 22kV terminal station supplies Melbourne Water. ACIL Allen assumed that maximum demand at this terminal station would be flat for the forecast period as shown in Figure 24.

Figure 24 **Maximum demand at Brooklyn 22kV terminal station**

Source: ACIL Allen Consulting

The Keilor West terminal station is quite new. It was first established in Winter 2011 so there are only a very few years of data from which to estimate growth. Rather than relying on this limited data, growth at this terminal station was estimated using historical growth at the zone substations connected to it.

5.5 Baseline forecasts

Baseline forecasts were computed by applying the growth rate to the starting point and adding anticipated block loads and future network transfers.

Block load adjustments were made at the Brunswick terminal station as follows.

1. demand was added at Brunswick (BTS) to account for the redevelopment of the former Australian Paper site at Fairfield

2. demand was removed at Thomastown (TTSB3B4) to account for the closure of the Ford manufacturing plant at Broadmeadows in 2016

The adjustments themselves were as shown in Table 13 below. The same adjustments were made in both summer and winter.

Table 13 **Block load adjustments – incremental MW**

Region	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Brooklyn TS 66kV										
Brooklyn TS 22kV										
Brunswick TS		0.6	1.2	1.8	1.2	0.6	0.6			
Thomastown TS B3B4			-10.23							

Note: changes shown here are incremental.
Source: JEN

5.6 Post model adjustments

The baseline forecasts are now adjusted to account for changes in demand that have not otherwise been accounted for in the methodology.

A post model adjustment was made to account for the impact of increased penetration of solar PV.[7] The method by which that adjustment was estimated is discussed in chapter 6. Broadly, a financial model was used to estimate take up rates for PV systems. The output of those systems during likely peak demand times was estimated and subtracted from the projected latent demand.

It should be noted that no adjustment was made for the future impact of embedded generators other than PV. Further, no adjustment was made for other 'disruptive technologies'. While there may be impacts during the forecast period they are uncertain and have not been estimated here.

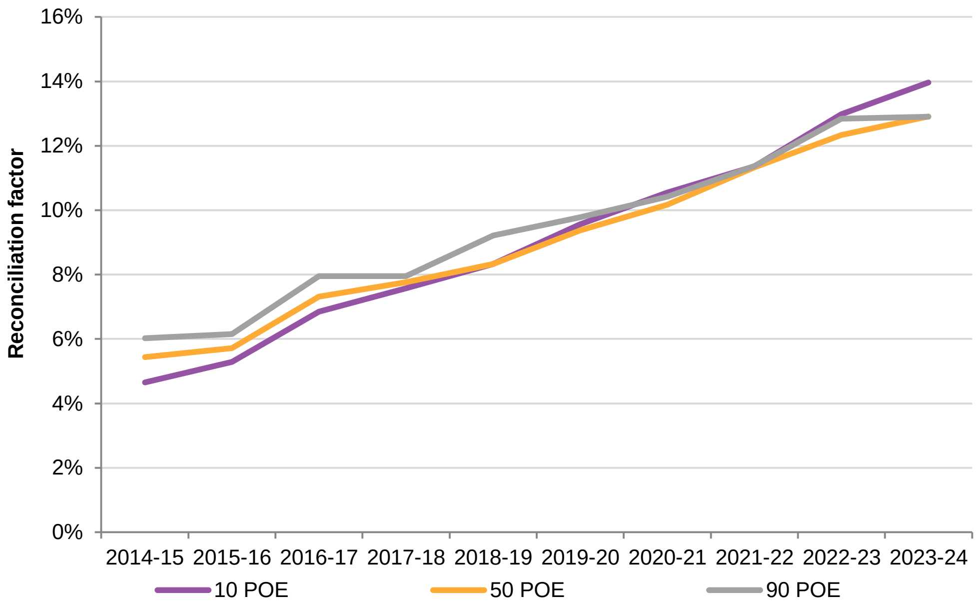
5.7 Reconciliation to system forecast

The final stage in the demand forecasting process is to reconcile the terminal station forecasts to the system forecast. The system forecast was prepared by the same process described above, though the block loads adjustment were not required to be made at the system level demand as this is reflected in the economic growth model.

Reconciliation of the system and terminal station level forecasts requires calculation of reconciliation factor. These factors are applied to each terminal station coincident demand forecast to obtain the final coincident demand forecasts. Figure 25 shows the reconciliation factors for each year.

[7] The ongoing impact of existing systems was also taken into account in the same way.

Figure 25 **Reconciliation factors by year, Summer, 2014-15 to 2023-24**



Source: ACIL Allen Consulting

5.8 System level forecasting methodology

The process for generating maximum demand forecasts at the system level was consistent with the terminal station methodology outlined above. Separate forecasts were developed for summer, and for winter.

Broadly, the approach to forecasting system level maximum demand was:

- estimate an econometric model relating daily maximum demand to the drivers considered in chapter 4
- for each forecast year, estimate maximum demand:
  - using temperature data from each day since 1980 (i.e. 3029 forecasts in summer, 5108 forecasts in winter)
  - using the values of other drivers relating to that forecast year (e.g. GSP, price, PV capacity)
  - generating a draw from the distribution of the error term
- store the maximum demand for each year of temperature data (35 observations for each forecast year)
- repeat this process 99 times (3,500 total simulated maximum demand values).

The 10, 50 and 90 PoE levels are then determined by considering percentiles of the 3,500 simulated maximum demand values.

Two factors were not included in the methodology that are worth noting, namely the price of gas (a substitute in some cases) and the impact of so called ‘disruptive technologies.

The price of gas could potentially influence demand for electricity. Conceptually this would be accounted for using a cross price elasticity. However, given that the parameter of interest in this report is maximum demand and that, particularly in summer, this is sensitive to cooling load, the relationship with gas prices was assumed to be zero. There may be some impact in winter, though we anexpect it would be small. In any case, JEN’s terminal stations are ‘summer peaking’, meaning that maximum demand in summer is higher than it is in winter. For this reason this factor was not considered in winter either.

Similarly, no explicit adjustment was made for disruptive technologies that are not yet present in JEN’s network.[8] The impact that these technologies may have on maximum demand is highly uncertain and subject to the way they are used. For example, charging load from electric cars would potentially increase electricity demand substantially, but this is unlikely to occur at peak times. In fact, the batteries in thes cars could be used to reduce peak demand, though this would require substantial coordination and planning.

5.8.1 System level maximum demand - summer

At the system level, summer maximum demand was modelled from a dataset showing daily maximum demand for all ‘non-mild’ days.[9] The model expresses daily maximum demand as a function of the following factors:

- **GSP_t:** gross state product
- **Min_t*GSP_t:** minimum daily temperature, multiplied by gross state product
- **Max_t*GSP_t:** maximum daily temperature, multiplied by gross state product
- **Max_{t-1}:** maximum daily temperature on the previous day
- **Max_{t-2}:** maximum daily temperature on two days prior
- **Maxgt34**: indicator variable set to 1 when maximum temperature (max_t) is greater than 34 C
- **$Price_t$:** retail electricity price
- **$February_t$:** indicator variable, equal to ‘1’ if month is February, ‘0’ otherwise
- **$Monday_t$:** indicator variable, equal to ‘1’ if day is Monday, ‘0’ otherwise
- **$Friday_t$:** indicator variable, equal to ‘1’ if day is Friday, ‘0’ otherwise

This specification provided a good balance between explanatory power, sensible coefficients, and model parsimony. The final model is shown in equation (1).

$$
\begin{aligned}
MD_t = 441.1 - 4.36 \times 10^{-4} \times GSP_t + 2.00 \times 10^{-5} \times Min_t \\
\times GSP_t + 3.96 \times 10^{-5} \times Max_t \times GSP_t + 1.76 \\
\times Max_{t-1} + 1.01 \times Max_{t-2} + 20.42 \\
\times MAXgt34 - 6.91 \times Price_t + 15.65 \\
\times February_t - 18.08 \times Friday_t + e_t
\end{aligned} \tag{1}
$$

Table 14 summarises the coefficients estimated using this specification.

[8] This does not apply to solar PV systems, which were taken into account in both the system and spatial forecasts.

[9] ‘non-mild’ days means that weekends, public holidays and days with mild temperatures were omitted as for the spatial models.

Table 14 **System maximum demand model (summer), estimated coefficients**

Variable	Coefficient	Standard error	t-statistic	p-value
Constant	441.1	43.02	10.25	0.00
GSP	-4.36E-04	1.97E-04	-2.22	0.03
MIN*GSP	2.00E-05	1.95E-06	10.25	0.00
MAX*GSP	3.96E-05	1.41E-06	28.06	0.00
MAX_{t-1}	1.76	0.42	4.18	0.00
MAX_{t-2}	1.07	0.32	3.30	0.00
MAXgt34	20.42	5.84	3.50	0.00
$PRICE_t$	-6.91	1.02	-6.77	0.00
FEB	15.65	3.33	4.70	0.00
FRI	-18.08	3.74	-4.84	0.00
R^2 (Adjusted):		0.87		
Standard error of regression:		32.6		

Source: ACIL Allen Consulting

The coefficients on lagged temperature are positive, meaning that as temperature increases maximum demand is forecast to increase also. The GSP coefficient must be interpreted in conjunction with the minimum and maximum temperature interactions. While the coefficient on GSP itself is negative, the interaction terms with temperature more than compensate. The positive coefficients on interactions between temperature and GSP suggest that sensitivity to temperature increases as economic growth continues. This is true for both daytime (the maximum temperature interaction) and night-time (minimum temperature interaction)

These coefficients were combined with:

- forecasts of the variables/drivers
- historical temperature data from 1980 to 2014
- simulated draws from a normal distribution, with a mean of zero, and standard deviation of 32.6.

The outputs were adjusted to account for the impact of solar PV systems forecast to be installed in future.[10] Consistent with the terminal station models, no adjustment was made for other forms of embedded generation or other disruptive technologies.

This was done by taking the capacity projections discussed in chapter 6 and multiplying by a 'capacity factor' to reflect the expected output of those systems during peak times. The capacity factor, which was calculated from AEMO's 2014 National Electricity Forecasting Report, varies over the forecast period as shown in Table 15.

Table 15 **Projected peak capacity factors for solar PV**

Year	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
PV peak capacity factor	34%	29%	29%	30%	30%	22%	23%	23%	23%	23%

Source: ACIL Allen calculations based on AEMO 2014 National Electricity Forecasting Report

10 The impact of existing systems was reflected in the data upon which the model was based. Therefore, unlike the terminal station models, this model makes a post model adjustment only for new systems.

5.8.2 System level maximum demand - winter

For system level forecasts, maximum demand was modelled as a function of the following factors:

- **GSP_t:** gross state product
- **Min_t*GSP_t:** minimum daily temperature, multiplied by gross state product
- **Max_t*GSP_t:** maximum daily temperature, multiplied by gross state product
- **Max_{t-1}:** maximum daily temperature on the previous day
- **Max_{t-2}:** maximum daily temperature on two days prior
- **Price:** retail electricity price
- **April:** indicator variable, equal to '1' if month is April, '0' otherwise
- **June:** indicator variable, equal to '1' if month is June, '0' otherwise
- **September:** indicator variable, equal to '1' if month is September, '0' otherwise
- **October:** indicator variable, equal to '1' if month is October, '0' otherwise
- **$Monday_t$:** indicator variable, equal to '1' if day is Monday, '0' otherwise
- **$Friday_t$:** indicator variable, equal to '1' if day is Friday, '0' otherwise

This specification provided a good balance between explanatory power, sensible coefficients, and model parsimony. The final model is shown in equation (2).

$$\begin{aligned} MD_t = 456.9 &- 8.88 \times 10^{-6} \times Min_t \times GSP_t - 1.85 \times 10^{-5} \\ &\times Max_t \times GSP_t - 1.40 \times Max_{t-1} - 1.52 \\ &\times Max_{t-2} - 6.55 \times Price_t + 1684 \times 10^{-3} \\ &\times GSP_t - 30.76 \times April_t + 9.39 \times June_t \\ &- 26.65 \times September_t - 32.33 \times October_t \\ &- 7.92 \times Monday_t - 14.91 \times Friday_t + e_t \end{aligned} \tag{2}$$

Table 14 summarises the coefficients estimated using this specification.

Table 16 **System maximum demand model (winter), estimated coefficients**

Variable	Coefficient	Standard error	t-statistic	p-value
C	456.862	16.7	27.4	
GSP	1.64E-03	0.0	22.5	
MAX*GSP	-1.85E-05	0.0	-25.7	
MIN*GSP	-8.88E-06	0.0	-12.4	
MAX1	-1.41	0.2	-5.8	
MAX2	-1.52	0.2	-7.9	
RPRICET	-6.56	0.4	-16.5	
APR	-30.76	2.2	-14.0	
JUN	9.39	1.6	6.0	
SEPT	-26.65	1.7	-15.8	
OCT	-32.33	2.0	-16.3	
MON	-7.92	1.4	-5.7	
FRI	-14.91	1.4	-10.8	
R^2 (Adjusted):		0.84		
Standard error of regression:		18.1		

Source: ACIL Allen Consulting

As with the model for summer, the positive coefficient on GSP suggests that demand increases with higher levels of economic activity. The negative coefficients on the interactions between GSP and temperature indicate that the impact of higher GSP is lessened on warmer winter days. This is consistent with reasoning that as economic activity increases the use of electric heating increases also. Negative coefficients on lagged temperature imply an impact of sequences of cold days, in the same way as sequences of hot days increase electricity demand in summer.

The price in the previous year is found to have a negative impact on demand, and the coefficient on the interaction between price and maximum temperature suggests that as temperature increases price has even more of an impact on demand.

Finally, Demand in June is found to be higher than in July or August, while demand in April. September, and October is lower on average. As with the summer model, demand is forecast to be lower on Monday and Friday than on other weekdays.

These coefficients were combined with:

- forecasts of the variables/drivers
- historical temperature data from 1980 to 2014.
- simulated draws from a normal distribution, with a mean of zero, and standard deviation of 18.1.

No adjustment was made to the winter forecasts to account for the impact of PV. This reflects the fact that demand in JEN's region peaks in the morning or the evening, when PV output is limited. It is consistent with the approach taken by AEMO in the 2014 NEFR.

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 (3):

$$\begin{aligned}\ln(Capacity_t) = {} & 7.315 + 0.0004 * Payback_t \\ & + 0.289 * Rush - in_t + 1.274 * Rush - in2_t + \varepsilon_t\end{aligned} \tag{3}$$

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

$Rush\text{-}in2_t$ 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 17. 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 17 **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:

$$Capacity_t = \exp(7.315 + 0.0004 * Payback_t + 0.289 * rush - in_t + 1.274 * rush - in2_t + \varepsilon_t) \quad (4)$$

Therefore:

$$Capacity_t = 1503.04 * \exp(0.0004 * Payback_t) * \exp(0.289 * rush - in_t) * \exp(1.274 * rush - in2_t) * \exp(\varepsilon_t) \quad (5)$$

where the variables are as described above.

Projections of solar PV uptake by residential customers were produced by applying equation (5) 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.

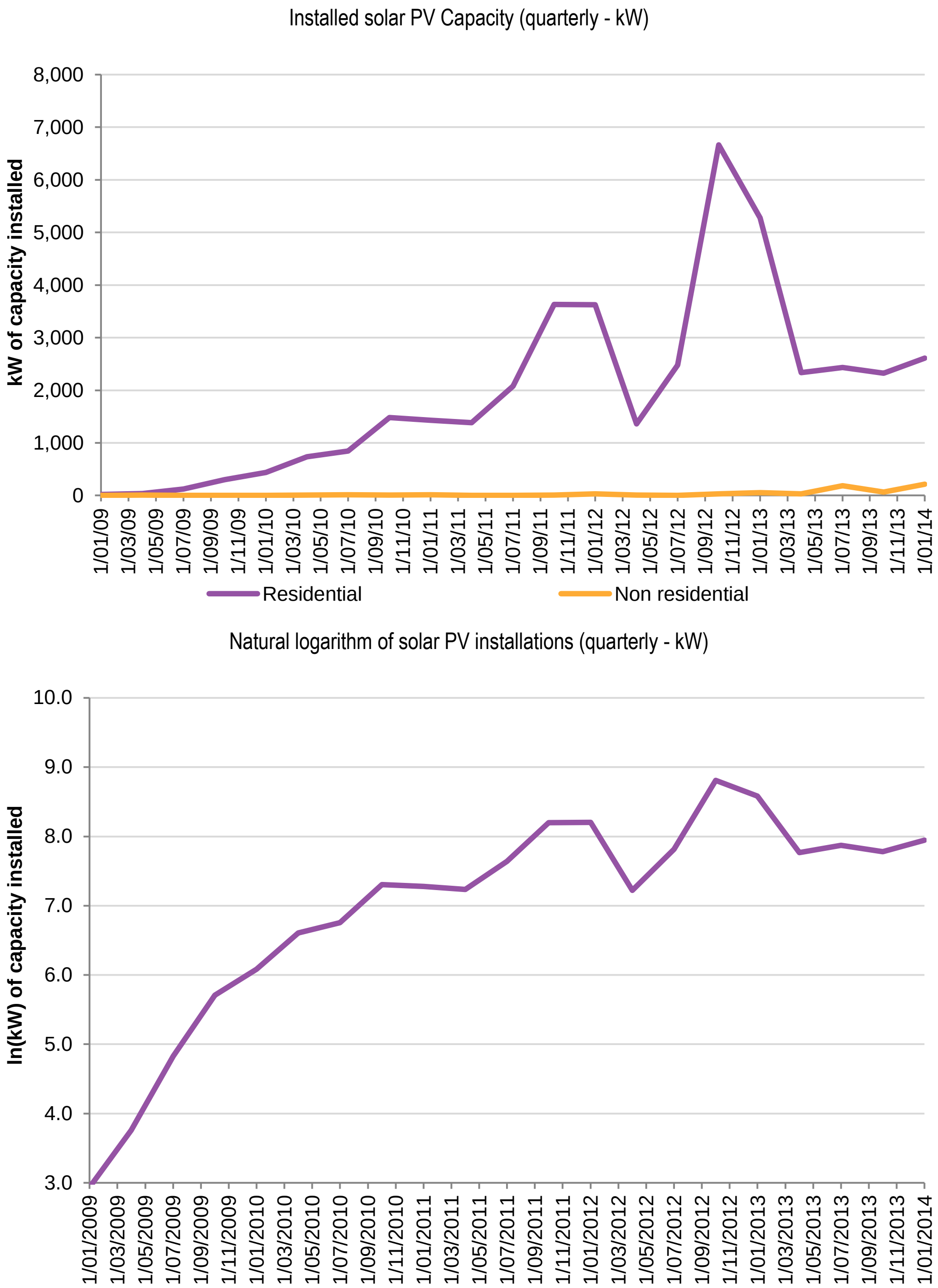
Section 6.4 provides a brief description of the 'rush-in' and rush-in2' independent variables.

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 26, which shows the level of capacity as well as its natural logarithm.

Figure 26 **Solar PV installations in JEN's region**



Source: ACIL Allen Consulting

Figure 26 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:

1. the payment received for electricity generated and exported to the grid
2. *plus* the value (avoided cost) of electricity generated and used on site
3. *plus* the value of any upfront payments received
4. *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 (6)

$$\begin{aligned} Payback_{ct} = {} & upfront\ payment_{ct} - installation\ cost_{ct} \\ & + avoided\ retail_{ct} + export\ revenue_{ct} \end{aligned} \quad (6)$$

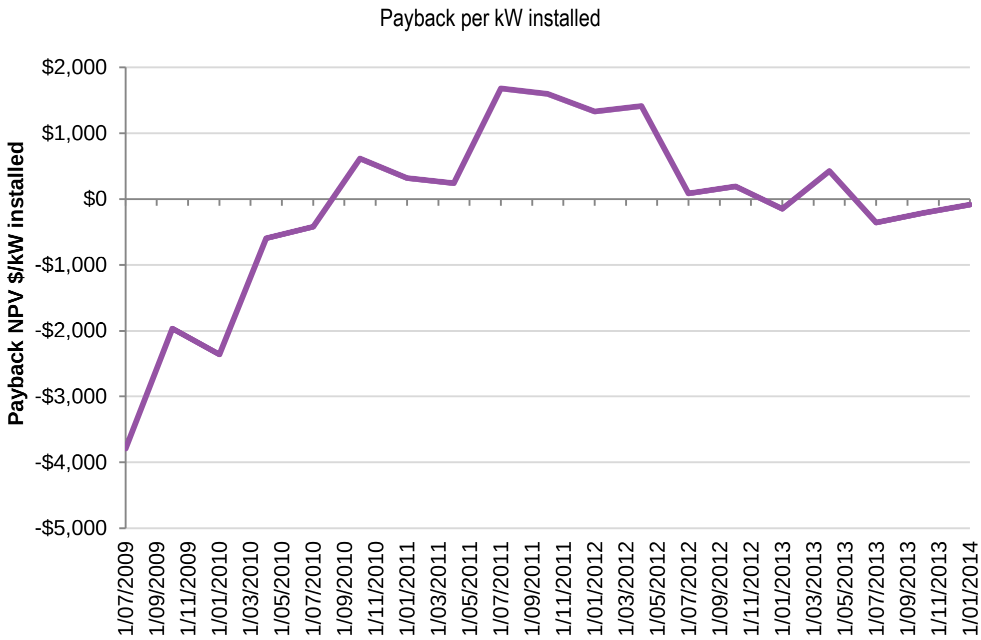
Where:

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 27, normalised to show payback per kW installed.

Figure 27 **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)[11] 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.

[11] 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.[12]

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 18. 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 18 **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.

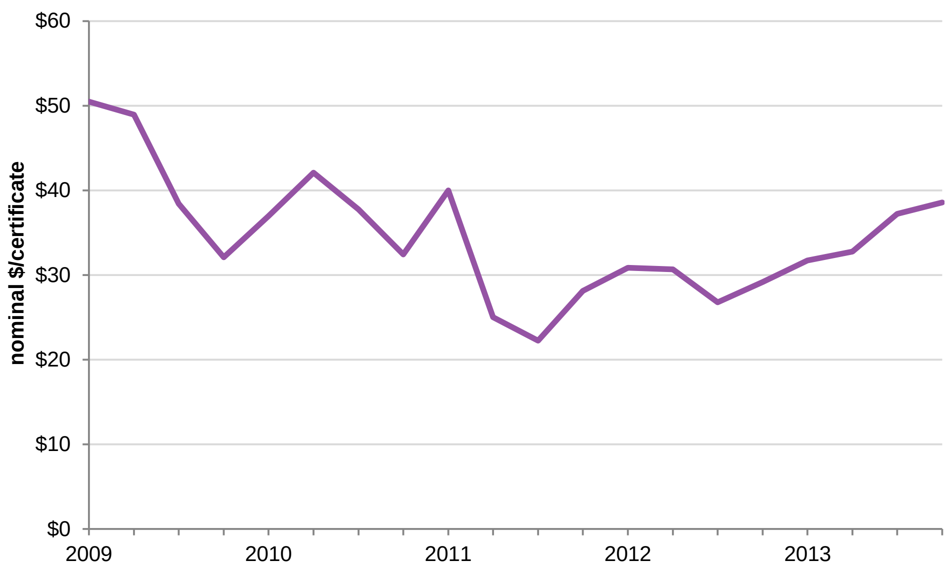
Source: ACIL Allen Consulting; *Renewable Energy (Electricity) Regulations 2001*

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 28.[13] 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.

12 Customers who received the SHCP rebate received the value of certificates as if the multiplier was 1.

13 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 28 **REC/STC prices (nominal $/certificate)**



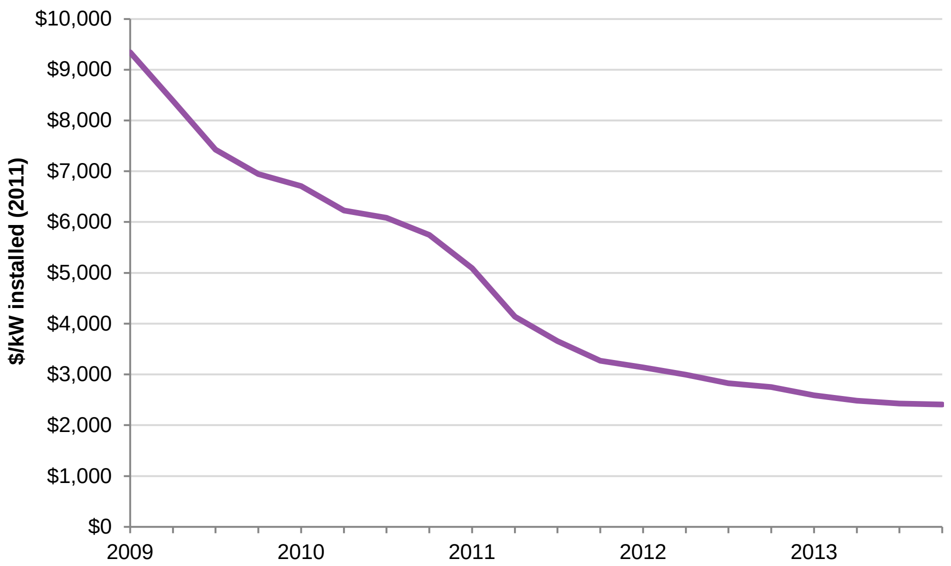
Note: REC prices prior to Q1 2011, STC prices subsequently.
Source: AFMA; ACIL Allen Consulting

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 29.

Figure 29 **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

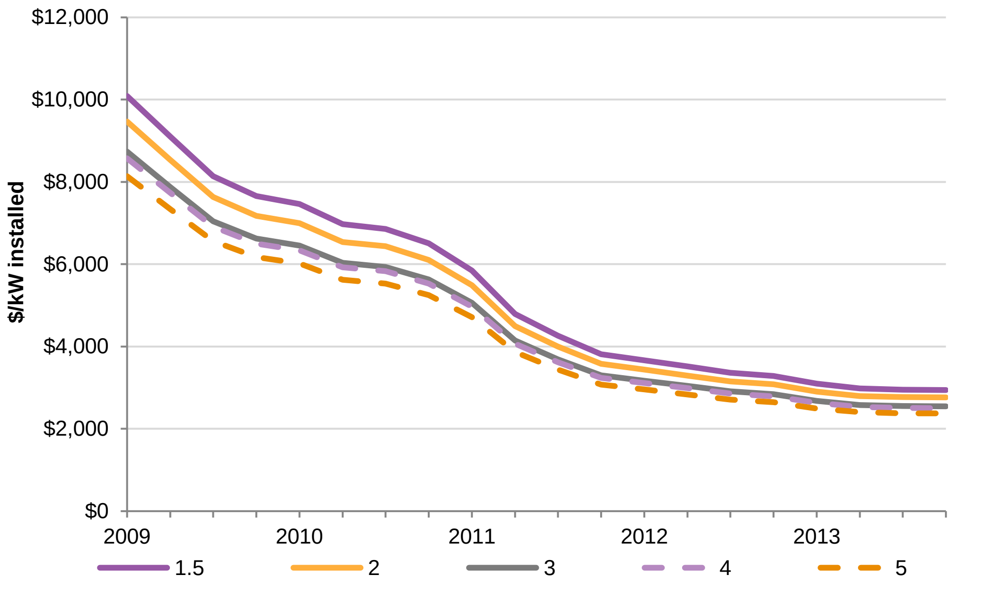
For the period from October 2012 to December 2013 (inclusive) the national average cost of installing a solar PV system in JEN's region was based on SolarChoice's "solar PV Price Check" publication.[14]

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 30.

Figure 30 **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.

14 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 19.

Table 19 **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"[15].

During this period the premia/discounts associated with different system sizes and described in Table 19 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:

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

[15] 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.[16]

Therefore, the estimated annual system output was as shown in Table 20.

Table 20 **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 21. 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 21.

16 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 21 **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

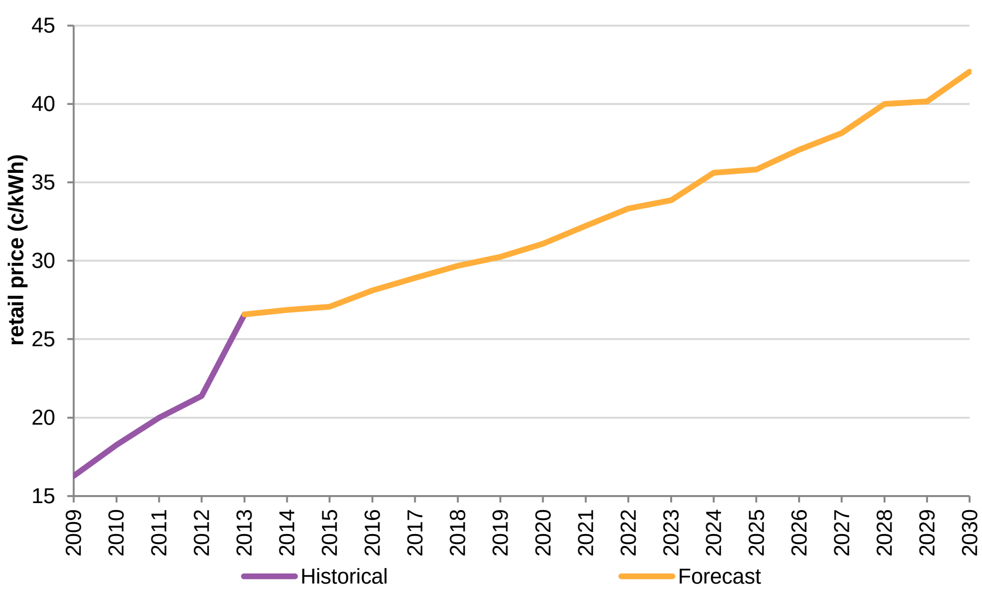
By assuming a minimum consumption level required in order to install each system size, the proportion of energy exported for each storage size is less variable across system sizes. These export rates were used to inform the relative payback for each system size, by assuming that paybacks for all customers 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 4.3. Empirical and projected retail electricity prices are shown in Figure 31.

Figure 31 **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[17]
- 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.

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[17] 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.

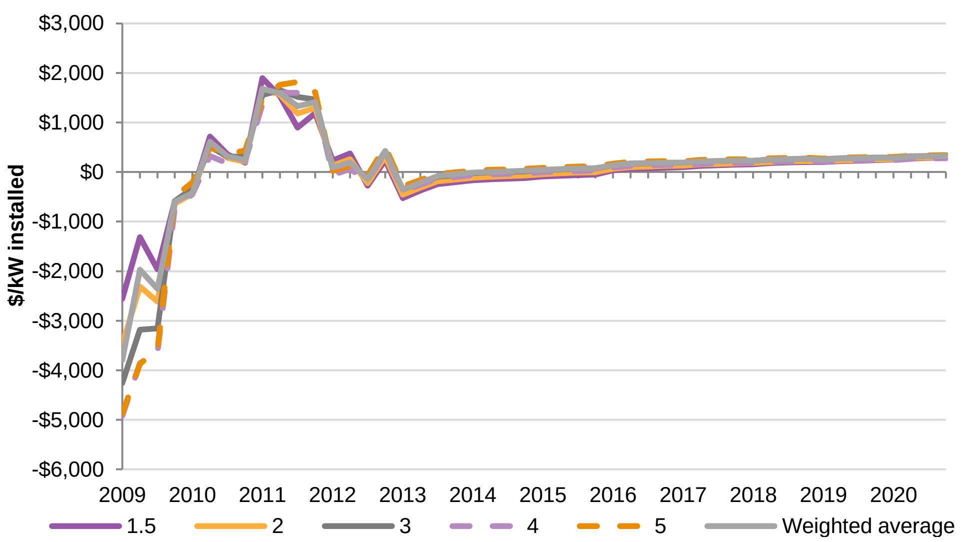
6.5 Results

6.5.1 Payback

The return on solar PV systems of various sizes is shown in Figure 32 (NB in the historical period the weighted average is the same as shown in Figure 27).

Figure 32 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 32 **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:

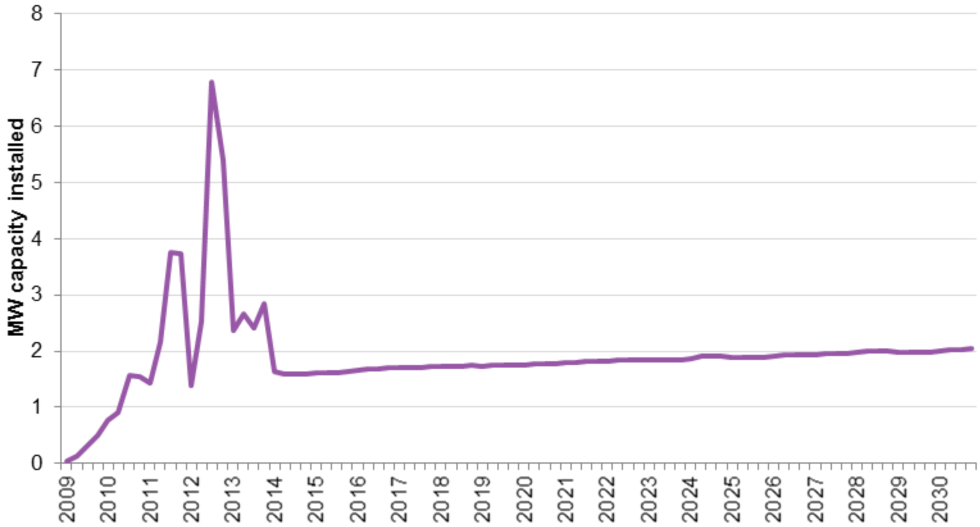
— electricity prices remain relatively stable

— 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 33, 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.

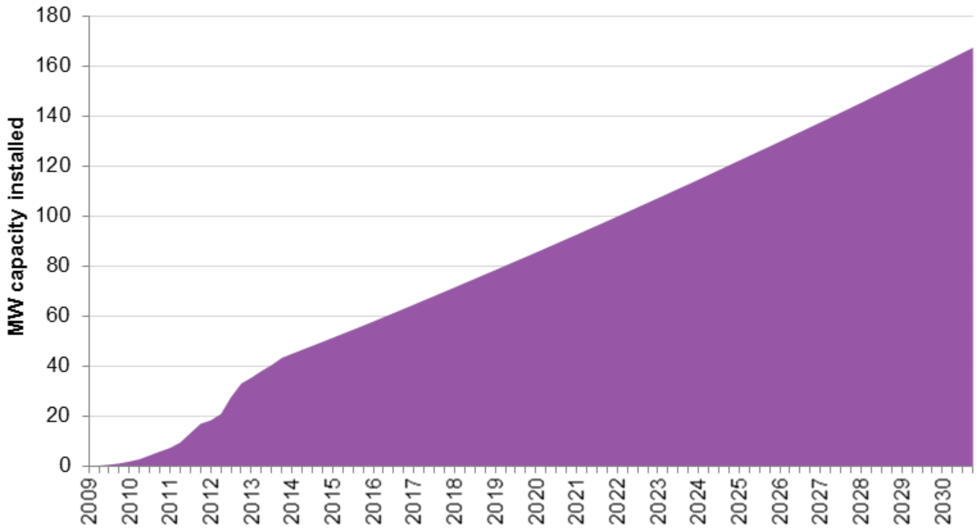
Figure 33 **Quarterly solar PV system installations**



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 34.

Figure 34 **Cumulative capacity of installed solar PV systems by system type**



Source: ACIL Allen Consulting

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