PV Solar Generation Data and Performance

Accompanying Appendix Seven to

Understanding the value of residential solar PV and storage in New Zealand

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Contents

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1 Introduction

Solar generation for each city for the typical meteorological year (TMY) was obtained from ANSA®'s solar farm generation model, ANSA-SolarFarm. This is described in Section 2. Section 3 outlines the PV system configurations used throughout the study for the main modelling (Base Case), and for assessment of sensitivities to changes from the Base Case PV system configurations. It then discusses performance indicators used in the study for solar performance, and presents the performance of the various system configurations used in the study. It also gives typical generation profiles of the various system configurations. Section 4 gives more detailed performance of the solar generation modelled as well as daily solar generation profiles that cover the year.

2 ANSA's solar farm generation model (ANSA-SolarFarm)

ANSA-SolarFarm builds a 54-year meteorological dataset for each site using satellite sources (Japanese Metrological Agency (JMA) MTSAT-1R, MTSAT-2, and Himawari-8), weather re-analysis data (NASA MERRA-2 and ECMWF ERA5-Land), and ground-based measurements (NIWA stations). The model used to construct this dataset is a machine learning model, trained and tested against ground-based measurements from NIWA stations. When one or more NIWA stations are sufficiently close to the site under study the measured data from those stations is used directly. If measured data is not available, or is inadequate, ANSA's model calculates the value of each meteorological variable over time using satellite and weather reanalysis data, as well as data from surrounding NIWA stations.

Meteorological variables used in this model include irradiance, wind speed, temperature, relative humidity, pressure, and precipitation. This approach allows a complete 54-year dataset to be constructed for any site across New Zealand at a high spatial and temporal resolution, with the best available data sources being used for each time period. As ANSA-SolarFarm is trained against ground-based data, and uses that data directly when available, the results are more complete and more accurate than other models that rely solely on satellite and/or weather reanalysis data. For this study a typical meteorological year is selected from the 54 years of solar generation.

ANSA's model models the power output of every module and inverter in the system (generally only one inverter in residential systems). This model includes temperature-dependent losses, PV module light induced degradation (when modelling over multiple years), wiring losses, and inverter losses. It also considers soiling losses, and the use of a rainfall data to model cleaning of the PV modules after rain, thus lowering soiling losses. The impacts of shading on the power output of each module is also modelled, including both topographic shading and inter-row shading between arrays. In this study, the PV modules are installed flat against the roof of a house, so the inter-row shading capabilities of the model are not required.

ANSA-SolarFarm includes bypass diodes in each PV module, which mitigate shading losses to some extent, particularly shading mismatch losses (mismatch in voltages across module strings). The generic models provided by other solar models use full-cell modules, thus shading losses have more impact. For ANSA-SolarFarm custom studies, the PV module type can be specified. If a half-cell module is specified, bypass diodes are positioned along the centre of the module, connecting each vertical substring. This gives better mitigation from shading losses.

Multiple system orientations and tilts can be modelled, as can multiple DC:AC ratios (inverter loading ratios) and PV module types. Monofacial PV modules are used in this study, since they are installed flat against the roof of a house, with minimal reflection. Hence the additional cost of bifacial PV modules is not included, although ANSA-SolarFarm can model bifacial PV modules if specified.

3 Solar Performance

The system configuration used throughout this study is a north facing roof and array, with a 30° slope from horizontal. Of course, not all homes have a roof with a north facing orientation on which to mount PV panels, and roof slopes vary considerable from almost flat roofs to steep roofs. For these reasons, several other configurations are considered and tested as sensitivities from the base configuration. Results from the sensitivities are summarised in the main report. This appendix investigates the generation performance of PV systems, using modelled data, in the four cities assessed, with various orientation and tilt configurations, and across the year. Since this report also examines the financial performance of solar as more distributor revenue is recovered from peak periods, the performance of PV is also investigated at traditional times of peak demand. These are winter mornings and evenings.

3.1 PV performance indicators

Two common indicators of solar performance are capacity factor and specific yield. Capacity factor gives the effective capacity of the PV installation that is converted to energy over a period of time. It includes the characteristics of the PV system, any losses in the PV system, the solar resource at the location, and ideally any topographic shading. Specific yield gives the energy output per unit of PV system capacity, for example kWh/kW. Specific yield can be calculated by multiplying the capacity factor by the number of hours in the period over which capacity factor is determined. For example, over a year, multiply capacity factor by 8,760 hours. This requires a known time period over which to multiply the capacity factor; and it is crucial that the time period is specified for both capacity factor and specific yield – a year is usually used, but monthly capacity factors are also given in this appendix. Like PV system cost discussed in Appendix Five, the performance measure given also requires a consistent and clear definition of capacity. As with costs, AC capacity (the inverter capacity) is used throughout the report and this appendix, rather than DC capacity (the PV array capacity). Thus, the inverter loading ratio (the ratio of PV array capacity to inverter AC capacity) must also be specified when giving capacity factor or specific yield. Since PV performance reduces over time (due to light induced degradation), it is also relevant to state the year for which performance is given.

3.2 Annual and monthly performance

The annual AC capacity factors for the range of tilt angles, orientations and inverter loading ratios considered for each city in the study are given in Table 1.[1] It is clear from this that Queenstown has the best solar performance of any of the four centres, and that a north facing array with a 45 degree tilt angle gives the highest performance in all cities. Significant improvement in performance is achieved by increasing the inverter loading ratio above 1.0 (over sizing the DC array capacity compared to the inverter capacity). Such a significant improvement in capacity is achieved for a relatively small increase in PV system cost, as discussed in Appendix Five.

[1] For the purposes of the study, the location of solar in Auckland was at the northern end of Queen Street near the harbour (-36.844, 174.767); Wellington, in Petone near the harbour roughly half-way along the Esplanade (-41.230, 174.884); Christchurch in central Christchurch just north of the Square (-43.530, 172.637); and in Queenstown in Frankton, near the airport (-45.022, 168.733).

Table 1: Annual AC capacity factors at various tilts from horizontal and roof (and array) orientations for modelled PV solar generation for: (a) an inverter loading ratio of 1.2; and (b) an inverter loading ratio of 1.0. All results are for the first year of operation.

(a) ILR = 1.2

City	Tilt angle	North	Northwest	1/2 east & 1/2 west
Auckland	15°	0.170	0.161	0.149
	20°	0.175	0.164	0.148
	30°	0.181	0.166	0.146
	45°	0.183	0.163	0.139
Wellington	15°	0.167	0.158	0.147
	20°	0.171	0.160	0.145
	30°	0.177	0.162	0.142
	45°	0.179	0.159	0.134
Christchurch	15°	0.167	0.160	0.145
	20°	0.172	0.162	0.144
	30°	0.178	0.166	0.141
	45°	0.180	0.164	0.133
Queenstown	15°	0.184	0.176	0.159
	20°	0.190	0.180	0.158
	30°	0.197	0.183	0.153
	45°	0.199	0.182	0.145

(b) ILR = 1.0

City	Tilt angle	North	Northwest	1/2 east & 1/2 west
Auckland	15°	0.141	0.134	0.124
	20°	0.145	0.136	0.123
	30°	0.151	0.138	0.121
	45°	0.153	0.136	0.116
Wellington	15°	0.139	0.132	0.122
	20°	0.143	0.134	0.121
	30°	0.148	0.135	0.118
	45°	0.149	0.132	0.112
Christchurch	15°	0.139	0.133	0.121
	20°	0.143	0.135	0.120
	30°	0.148	0.138	0.117
	45°	0.150	0.137	0.111
Queenstown	15°	0.153	0.147	0.132
	20°	0.158	0.150	0.131
	30°	0.164	0.153	0.128
	45°	0.166	0.152	0.120

Solar performance over various months of the year is of interest given that New Zealand is a winter peaking electricity system, with peak demands experienced during winter mornings and evenings. Combined with this is the typically lower hydro generation during the winter, resulting in less energy available and higher prices. Hence, solar performance by month is important. Table 2 and Table 3 give the monthly solar performance for Auckland and Queenstown respectively, as the most northern and southern cities, for two different tilt angles and all orientations. All centres and tilt angles are given in Section 4.

Table 2: Auckland monthly AC capacity factors at: (a) a 15-degree tilt from horizontal; and (b) a 30-degree tilt from horizontal, for various roof (array) orientations for modelled PV solar generation. The inverter loading ratio is 1.2 and all results are for the first year of operation.

(a) Auckland 15° tilt angle

City	Month	15° degree tilt		
		North	Northwest	1/2 east & 1/2 west
Auckland	January	0.247	0.241	0.238
	February	0.219	0.213	0.203
	March	0.188	0.174	0.165
	April	0.139	0.126	0.112
	May	0.109	0.097	0.079
	June	0.089	0.077	0.060
	July	0.097	0.084	0.067
	August	0.123	0.111	0.097
	September	0.162	0.151	0.139
	October	0.198	0.188	0.181
	November	0.235	0.243	0.225
	December	0.238	0.234	0.231

(b) Auckland 30° tilt angle

City	Month	30° degree tilt		
		North	Northwest	1/2 east & 1/2 west
Auckland	January	0.242	0.232	0.226
	February	0.221	0.213	0.196
	March	0.201	0.177	0.160
	April	0.158	0.134	0.113
	May	0.134	0.110	0.081
	June	0.114	0.092	0.062
	July	0.122	0.098	0.069
	August	0.144	0.122	0.099
	September	0.176	0.157	0.137
	October	0.203	0.186	0.175
	November	0.232	0.246	0.214
	December	0.231	0.225	0.219

Table 3: Queenstown monthly AC capacity factors at: (a) a 15-degree tilt from horizontal; and (b) a 30-degree tilt from horizontal, for various roof (array) orientations for PV solar modelled by ANSA. The inverter loading ratio is 1.2 and all results are for the first year of operation.

(a) Queenstown 15° tilt angle

City	Month	15° degree tilt		
		North	Northwest	1/2 east & 1/2 west
Queenstown	January	0.269	0.270	0.259
	February	0.243	0.236	0.224
	March	0.201	0.195	0.172
	April	0.150	0.139	0.115
	May	0.097	0.088	0.067
	June	0.084	0.073	0.051
	July	0.095	0.083	0.061
	August	0.129	0.118	0.093
	September	0.181	0.170	0.150
	October	0.229	0.220	0.205
	November	0.263	0.257	0.251
	December	0.273	0.270	0.266

(b) Queenstown 30° tilt angle

City	Month	30° degree tilt		
		North	Northwest	1/2 east & 1/2 west
Queenstown	January	0.263	0.266	0.245
	February	0.247	0.236	0.215
	March	0.217	0.207	0.167
	April	0.174	0.154	0.113
	May	0.120	0.103	0.067
	June	0.111	0.089	0.052
	July	0.122	0.100	0.061
	August	0.154	0.135	0.091
	September	0.200	0.181	0.147
	October	0.237	0.223	0.197
	November	0.259	0.249	0.238
	December	0.264	0.260	0.252

Table 2 and Table 3 show the extent of the reduction in solar generation over winter months, showing that for a north facing system with a 15-degree tilt located in Auckland, June's solar generation is 37% of that in January after accounting for the number of days per month. For the ease of comparison, the ratio of June to January average solar energy generation is summarised for each centre and two tilt angles in Table 4. As expected, a system with a higher tilt angle has comparatively more winter generation than a system with a lower tilt angle, and that winter generation is always higher for north facing systems. For this reason, the rate of return performance of the sensitivity case of higher tilt angle north facing systems is of interest, especially when retail electricity prices more accurately reflect the cost of electricity generated and supplied by season. Finally, Table 4 shows some difference in June-to-January energy ratios between cities, most likely influenced by local weather and latitude.

Table 4: Ratio of June to January average monthly solar energy generation, after accounting for the number of days per month. ILR=1.2.

City	15° degree tilt			30° degree tilt		
	North	Northwest	1/2 east & 1/2 west	North	Northwest	1/2 east & 1/2 west
Auckland	37%	33%	26%	48%	41%	28%
Wellington	30%	27%	20%	40%	33%	22%
Christchurch	33%	29%	21%	45%	36%	24%
Queenstown	32%	28%	20%	44%	35%	22%

3.3 PV generation performance coincident with peak demand periods

For the reasons outlined earlier – that New Zealand's peak electricity capacity and energy demand occurs in the winter – it has been suggested that PV panels facing east and west would give better overall financial performance. This is because they are likely to capture more energy in the morning and in the evening, thus generating more energy during the morning and evening peak periods. This is why the 'half-east and half-west' PV system is included in the analysis and in the sensitivity results, with its rate of return difference tested in the main report. This section investigates generation profiles over a day, to show how they perform by half-hour of the day, for various orientations and tilt angles. Generation profiles for both the days with maximum and minimum energy generation in the time period of interest are shown.

To begin with, profiles for Auckland and Queenstown maximum daily energy generation and minimum daily energy generation are shown in Figure 1. These illustrate the extremes between summer and winter. Figure 2 shows the daily generation profiles for these cities on the days in June and July when energy generation between 7am and 9am was highest and lowest. In both cities, on the maximum days, there is some generation between 8am and 9am, and a very small amount between 7am and 8am in Queenstown with the half-east and half-west array. This would seem to support the idea that this array orientation might perform better. However, over the rest of the day the generation from this system orientation is a fraction of that of the north facing array. Moreover, on the minimum day, where there is least energy in the 7am-9am period, there appears to be no generation at all before 8:30am.

Similar results can be seen in Figure 3 over the 5pm-7pm period. However, in this case the half-east and half-west facing arrangement does not provide more energy than the north facing arrangement during the evening peak even on the maximum day. This is most likely because the sun sets further from west and due to local topology. Further, on the minimum day in Figure 3 there appears to be no generation after 5:30pm.

From these figures it appears that:

(1) there is so little additional energy generated from a half-east and half-west system in the morning and evening peak periods, and that there is so much less energy generated during

the rest of the day, that a half-east and half-west system will not materially lift performance compared to a north facing array, or even a northwest facing array. Further, this will be the case even when peak energy and export pricing is significantly higher in the peak periods.

(2) It is simply not possible to rely on solar generation alone to reduce consumption during peak periods, unless it is combined with a battery system that is operated in such a way as to store energy off-peak and/or when there is excess solar generation and to release it during peaks.

The first of these is tested in the sensitivities in the main report. Graphs comparing each sensitivity case's solar generation profiles to the base case for Wellington generation are given in the next section. The second of these observations is tested in the storage section of the main report.

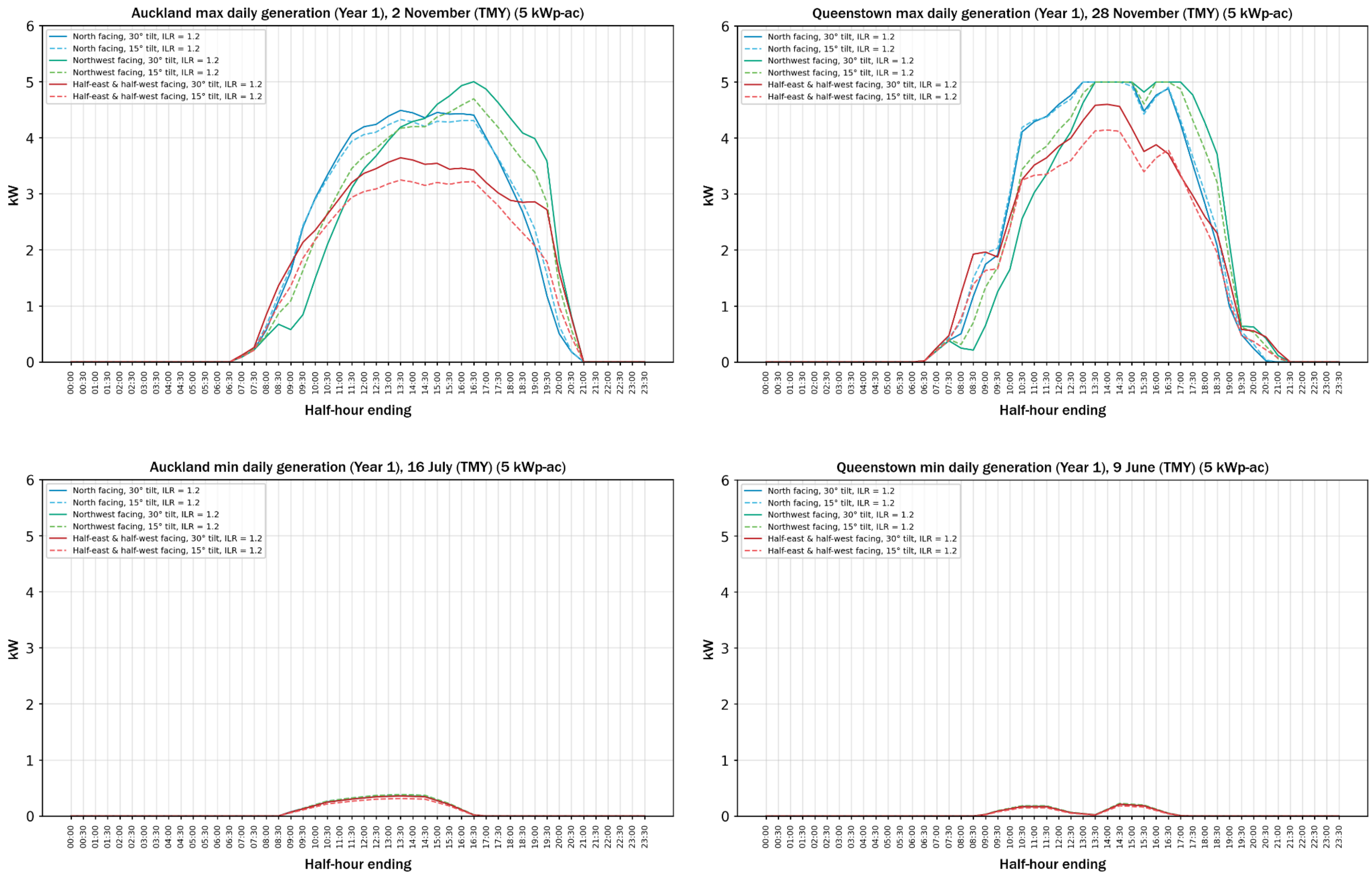


Figure 1: Maximum and minimum daily energy generation days for both Auckland and Queenstown. Queenstown shows clipping, which results from the array being larger than the inverter.

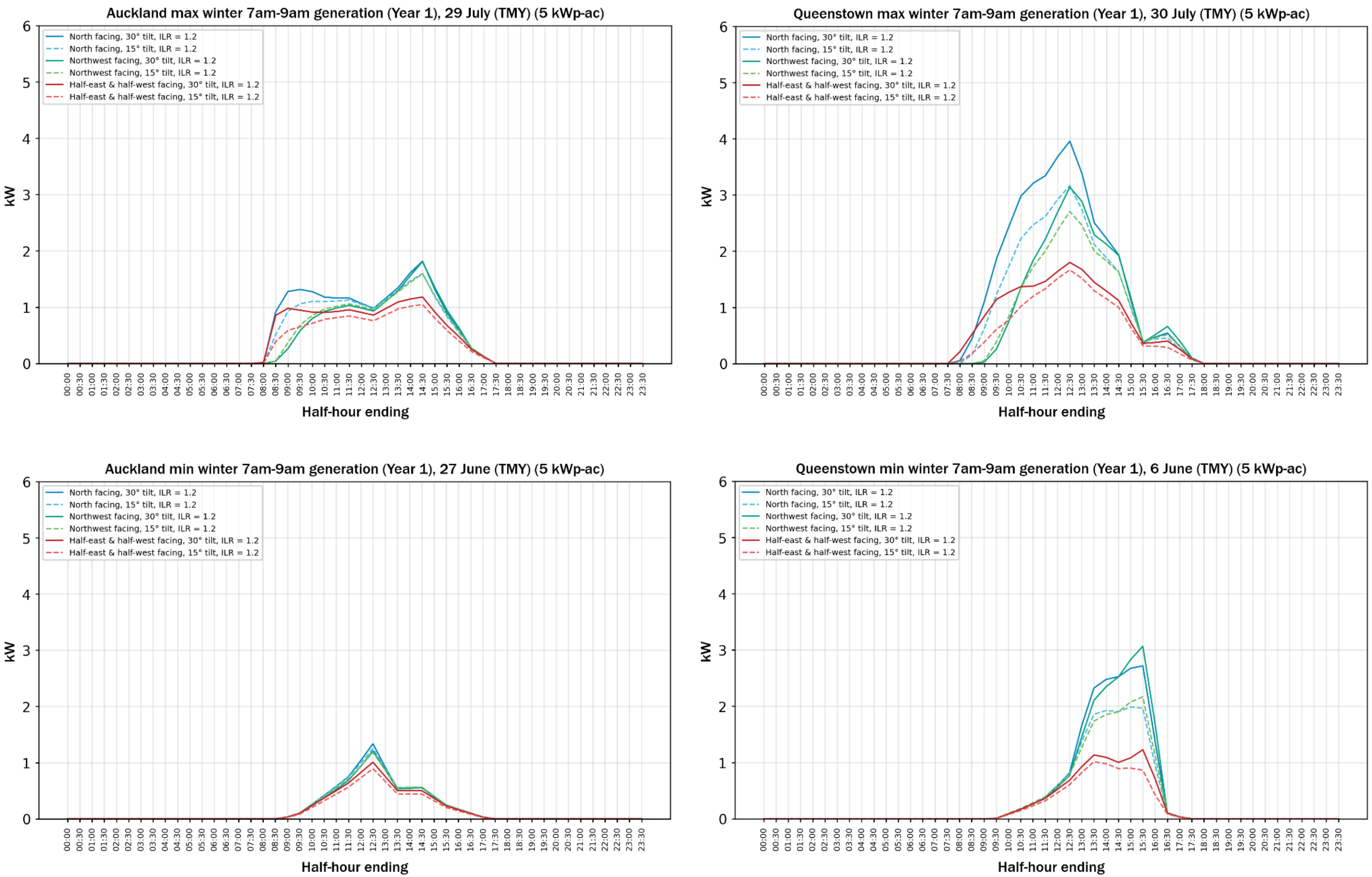


Figure 2: Maximum and minimum winter 7am-9am daily energy generation days for both Auckland and Queenstown. For these graphs winter is June and July.

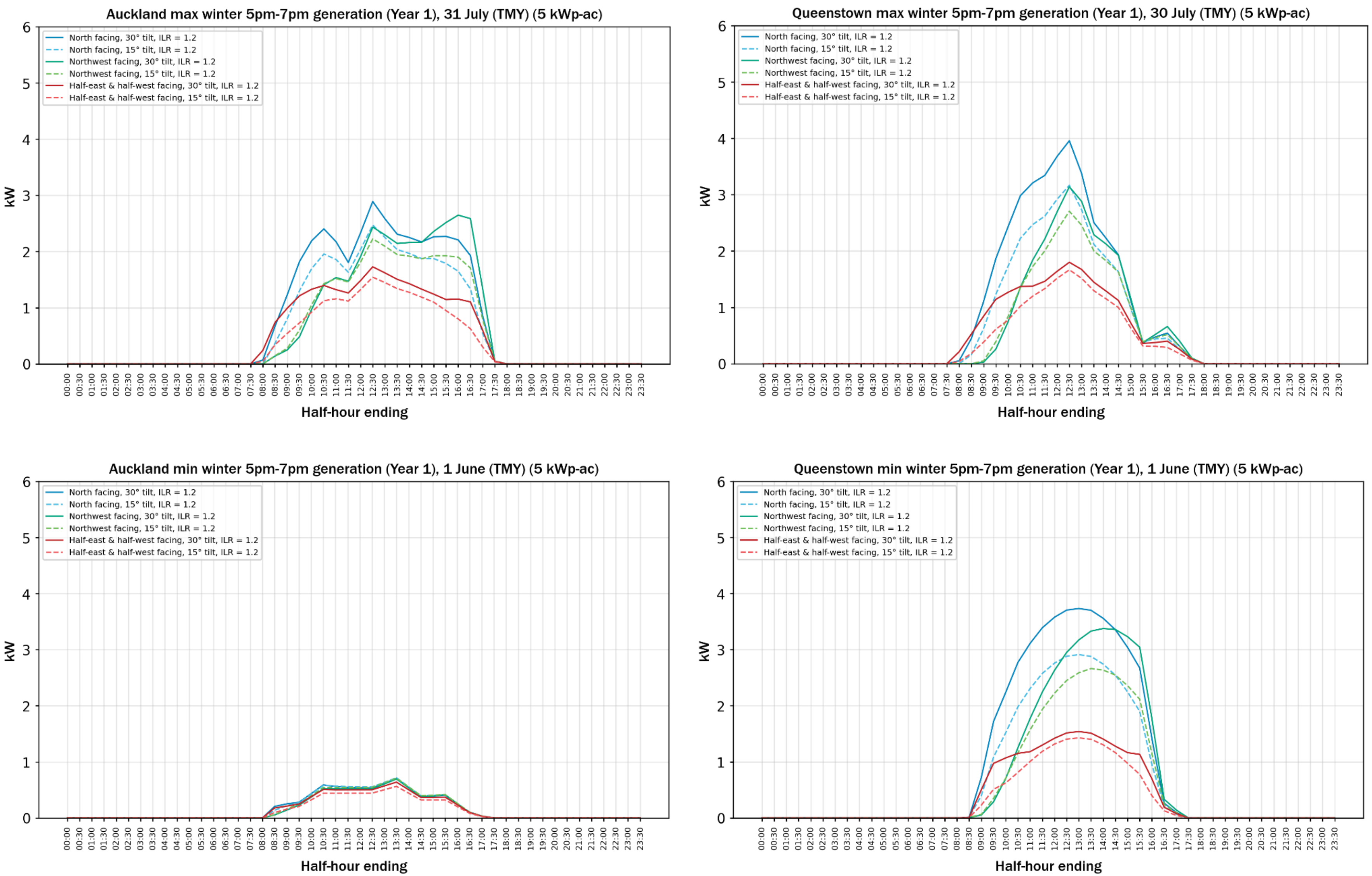


Figure 3: Maximum and minimum winter 5pm-7pm daily energy generation days for both Auckland and Queenstown. For these graphs winter is June and July.

4 Detailed solar performance and generation profiles

Table 5 and Table 6 give monthly capacity factors for all tilts and orientations modelled for the two inverter loading ratios.

Figure 4 to Figure 8 compare the Base Case solar generation profiles with each sensitivity case for solar using Wellington solar generation of a 5 kW-ac system as an example. The cases compared are:

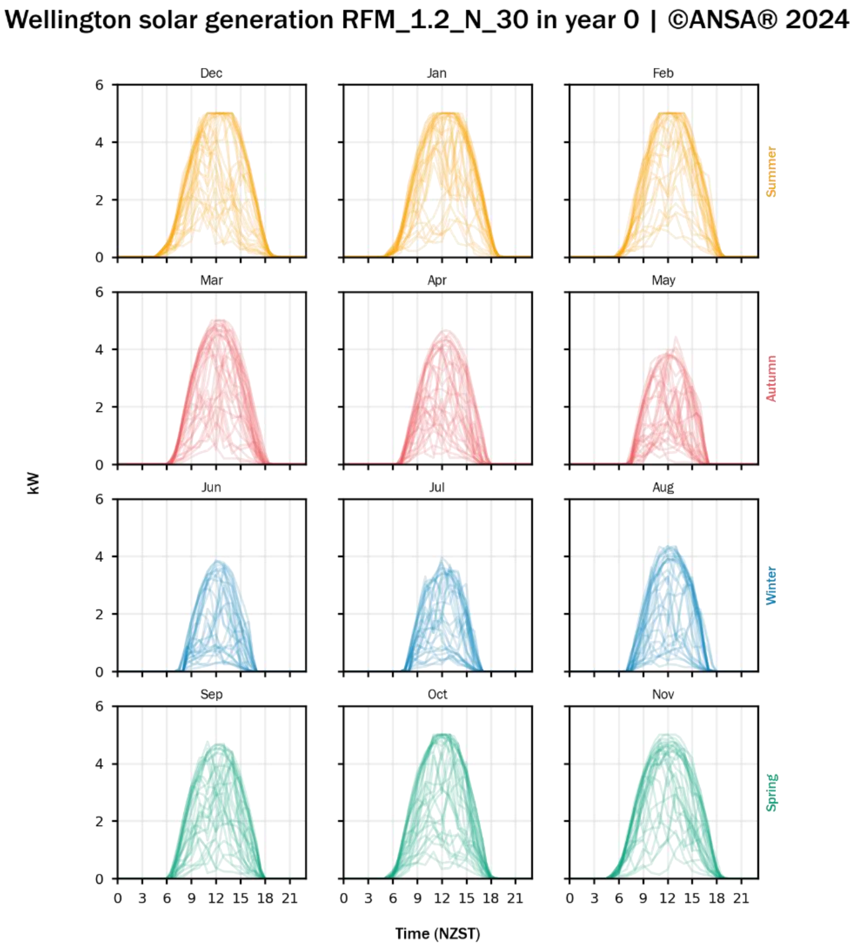
- Figure 4 compares the Base Case with DC array capacity oversized (DC:AC ratio or ILR of 12) to one that matches the inverter capacity (the low ILR sensitivity case).
- Figure 5 compares the Base Case with 30° module tilt to a 45° module tilt (the 45 degree tilt sensitivity case).
- Figure 6 compares the Base Case with 30° module tilt to a 15° module tilt (the 15-degree tilt sensitivity case).
- Figure 7 compares the Base Case with north oriented roof and array to a northwest oriented roof and array (the northwest sensitivity case).
- Figure 8 compares the Base Case with north oriented roof and array to an east-west oriented roof and array (the half-east and half-west sensitivity case).

Table 5: Monthly capacity factors for the first year of operation and an inverter loading ratio of 1.2 for a range of tilts and orientations. 30° tilt from horizontal and north facing are used in all Base Cases in the main report, while 15° and 45° tilts and northwest and ½ east / ½ west orientations are used in sensitivity cases.

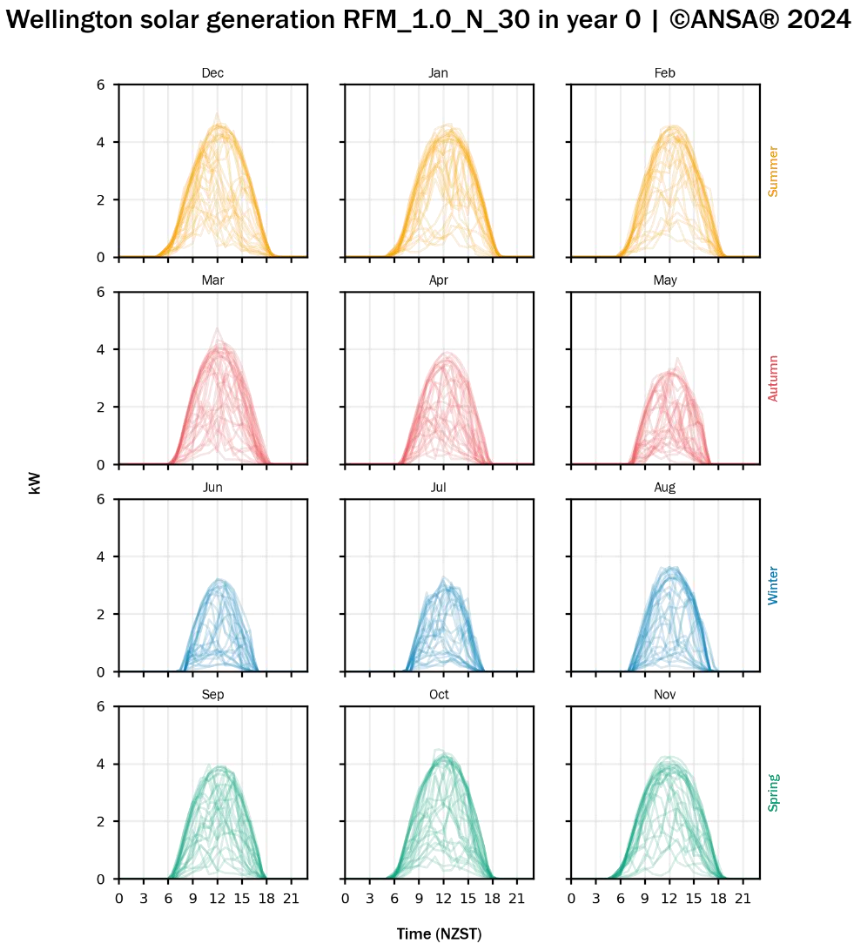
City	Month	15° degree tilt			20° degree tilt			30° degree tilt			45° degree tilt		
		North	Northwest	1/2 east & 1/2 west	North	Northwest	1/2 east & 1/2 west	North	Northwest	1/2 east & 1/2 west	North	Northwest	1/2 east & 1/2 west
Auckland	January	0.247	0.241	0.238	0.247	0.239	0.235	0.242	0.232	0.226	0.226	0.217	0.211
	February	0.219	0.213	0.203	0.221	0.214	0.201	0.221	0.213	0.196	0.214	0.205	0.185
	March	0.188	0.174	0.165	0.194	0.176	0.163	0.201	0.177	0.160	0.203	0.172	0.153
	April	0.139	0.126	0.112	0.146	0.129	0.113	0.158	0.134	0.113	0.169	0.137	0.112
	May	0.109	0.097	0.079	0.118	0.102	0.080	0.134	0.110	0.081	0.150	0.118	0.081
	June	0.089	0.077	0.060	0.098	0.083	0.061	0.114	0.092	0.062	0.131	0.100	0.063
	July	0.097	0.084	0.067	0.106	0.089	0.068	0.122	0.098	0.069	0.140	0.106	0.070
	August	0.123	0.111	0.097	0.131	0.116	0.097	0.144	0.122	0.099	0.158	0.127	0.099
	September	0.162	0.151	0.139	0.167	0.154	0.138	0.176	0.157	0.137	0.181	0.156	0.132
	October	0.198	0.188	0.181	0.200	0.188	0.179	0.203	0.186	0.175	0.198	0.177	0.165
	November	0.235	0.243	0.225	0.235	0.245	0.222	0.232	0.246	0.214	0.218	0.238	0.199
	December	0.238	0.234	0.231	0.237	0.232	0.228	0.231	0.225	0.219	0.214	0.210	0.202
Wellington	January	0.256	0.253	0.247	0.255	0.251	0.244	0.250	0.245	0.236	0.233	0.231	0.220
	February	0.233	0.225	0.215	0.235	0.226	0.212	0.236	0.223	0.205	0.228	0.213	0.189
	March	0.181	0.169	0.157	0.186	0.171	0.156	0.194	0.173	0.153	0.197	0.170	0.146
	April	0.129	0.119	0.104	0.136	0.123	0.104	0.146	0.128	0.103	0.156	0.130	0.100
	May	0.091	0.081	0.065	0.099	0.086	0.066	0.113	0.093	0.066	0.127	0.100	0.066
	June	0.075	0.066	0.049	0.083	0.071	0.049	0.097	0.079	0.050	0.112	0.087	0.050
	July	0.082	0.071	0.056	0.089	0.075	0.056	0.103	0.082	0.057	0.117	0.089	0.058
	August	0.118	0.107	0.087	0.126	0.112	0.087	0.140	0.120	0.087	0.154	0.126	0.084
	September	0.160	0.150	0.136	0.166	0.153	0.135	0.175	0.157	0.134	0.181	0.158	0.129
	October	0.199	0.191	0.181	0.202	0.192	0.179	0.205	0.192	0.173	0.201	0.185	0.162
	November	0.235	0.230	0.225	0.236	0.229	0.223	0.232	0.224	0.216	0.218	0.210	0.201
	December	0.247	0.243	0.241	0.246	0.240	0.238	0.239	0.232	0.228	0.222	0.214	0.209
Christchurch	January	0.245	0.245	0.238	0.244	0.245	0.235	0.239	0.241	0.228	0.223	0.229	0.213
	February	0.214	0.207	0.198	0.216	0.208	0.195	0.217	0.206	0.189	0.210	0.198	0.177
	March	0.182	0.173	0.156	0.187	0.176	0.154	0.195	0.180	0.150	0.199	0.179	0.142
	April	0.124	0.115	0.097	0.132	0.119	0.098	0.144	0.126	0.098	0.155	0.131	0.096
	May	0.092	0.082	0.064	0.100	0.086	0.065	0.114	0.094	0.065	0.129	0.102	0.065
	June	0.079	0.068	0.049	0.088	0.074	0.050	0.105	0.084	0.052	0.124	0.094	0.054
	July	0.085	0.073	0.056	0.093	0.078	0.056	0.108	0.086	0.056	0.123	0.093	0.056
	August	0.123	0.113	0.091	0.131	0.118	0.091	0.146	0.127	0.090	0.160	0.135	0.088
	September	0.167	0.159	0.139	0.174	0.164	0.139	0.184	0.170	0.137	0.191	0.173	0.131
	October	0.205	0.196	0.184	0.208	0.197	0.181	0.212	0.196	0.175	0.209	0.189	0.162
	November	0.240	0.235	0.229	0.240	0.235	0.226	0.237	0.231	0.219	0.224	0.218	0.204
	December	0.250	0.252	0.244	0.248	0.251	0.241	0.241	0.247	0.233	0.222	0.233	0.216
Queenstown	January	0.269	0.270	0.259	0.268	0.270	0.255	0.263	0.266	0.245	0.245	0.252	0.228
	February	0.243	0.236	0.224	0.246	0.237	0.221	0.247	0.236	0.215	0.239	0.227	0.201
	March	0.201	0.195	0.172	0.208	0.200	0.171	0.217	0.207	0.167	0.222	0.209	0.159
	April	0.150	0.139	0.115	0.159	0.145	0.115	0.174	0.154	0.113	0.187	0.160	0.109
	May	0.097	0.088	0.067	0.106	0.094	0.067	0.120	0.103	0.067	0.134	0.111	0.065
	June	0.084	0.073	0.051	0.094	0.079	0.051	0.111	0.089	0.052	0.129	0.099	0.051
	July	0.095	0.083	0.061	0.105	0.089	0.061	0.122	0.100	0.061	0.140	0.109	0.060
	August	0.129	0.118	0.093	0.138	0.125	0.093	0.154	0.135	0.091	0.170	0.143	0.088
	September	0.181	0.170	0.150	0.189	0.174	0.149	0.200	0.181	0.147	0.208	0.182	0.141
	October	0.229	0.220	0.205	0.233	0.222	0.203	0.237	0.223	0.197	0.234	0.217	0.185
	November	0.263	0.257	0.251	0.263	0.256	0.247	0.259	0.249	0.238	0.244	0.234	0.222
	December	0.273	0.270	0.266	0.271	0.268	0.262	0.264	0.260	0.252	0.244	0.242	0.233

Table 6: Monthly capacity factors for the first year of operation and an inverter loading ratio of 1.0 for a range of tilts and orientations. An ILR of 1.0 is used in a sensitivity case in the main report.

City	Month	15° degree tilt			20° degree tilt			30° degree tilt			45° degree tilt		
		North	Northwest	1/2 east & 1/2 west	North	Northwest	1/2 east & 1/2 west	North	Northwest	1/2 east & 1/2 west	North	Northwest	1/2 east & 1/2 west
Auckland	January	0.206	0.200	0.198	0.205	0.199	0.195	0.202	0.193	0.188	0.188	0.180	0.175
	February	0.182	0.177	0.169	0.184	0.178	0.168	0.184	0.177	0.163	0.178	0.170	0.154
	March	0.157	0.145	0.137	0.161	0.146	0.136	0.167	0.147	0.133	0.169	0.143	0.127
	April	0.115	0.104	0.093	0.121	0.107	0.094	0.132	0.112	0.094	0.141	0.114	0.093
	May	0.091	0.080	0.066	0.098	0.085	0.066	0.111	0.092	0.067	0.125	0.098	0.067
	June	0.074	0.064	0.049	0.081	0.069	0.050	0.094	0.076	0.051	0.109	0.083	0.052
	July	0.081	0.070	0.055	0.088	0.074	0.056	0.102	0.081	0.057	0.116	0.088	0.058
	August	0.102	0.092	0.080	0.109	0.096	0.081	0.120	0.102	0.082	0.131	0.106	0.082
	September	0.134	0.125	0.115	0.139	0.128	0.115	0.146	0.130	0.113	0.150	0.130	0.110
	October	0.164	0.156	0.151	0.167	0.156	0.149	0.169	0.154	0.145	0.165	0.147	0.137
	November	0.196	0.202	0.187	0.196	0.204	0.185	0.193	0.205	0.178	0.181	0.198	0.166
	December	0.198	0.195	0.192	0.197	0.193	0.190	0.193	0.188	0.182	0.178	0.174	0.168
Wellington	January	0.214	0.211	0.206	0.213	0.210	0.203	0.209	0.205	0.197	0.194	0.192	0.183
	February	0.195	0.188	0.179	0.197	0.188	0.177	0.198	0.186	0.170	0.191	0.177	0.158
	March	0.151	0.140	0.131	0.155	0.142	0.130	0.162	0.144	0.127	0.164	0.142	0.122
	April	0.107	0.099	0.087	0.113	0.102	0.086	0.122	0.106	0.086	0.129	0.108	0.083
	May	0.076	0.067	0.054	0.083	0.071	0.054	0.094	0.078	0.055	0.106	0.083	0.055
	June	0.062	0.054	0.040	0.069	0.058	0.041	0.080	0.065	0.041	0.093	0.072	0.042
	July	0.068	0.059	0.046	0.074	0.063	0.047	0.085	0.068	0.047	0.098	0.074	0.048
	August	0.098	0.089	0.073	0.105	0.093	0.072	0.116	0.100	0.072	0.128	0.105	0.070
	September	0.133	0.125	0.113	0.138	0.127	0.112	0.146	0.131	0.111	0.150	0.131	0.107
	October	0.165	0.159	0.150	0.168	0.160	0.148	0.171	0.160	0.144	0.167	0.154	0.134
	November	0.196	0.191	0.187	0.196	0.190	0.185	0.193	0.186	0.179	0.182	0.175	0.167
	December	0.208	0.203	0.201	0.206	0.201	0.198	0.201	0.194	0.190	0.185	0.179	0.175
Christchurch	January	0.204	0.204	0.198	0.203	0.204	0.196	0.199	0.201	0.190	0.185	0.190	0.177
	February	0.178	0.173	0.164	0.180	0.173	0.162	0.181	0.172	0.157	0.175	0.165	0.147
	March	0.151	0.144	0.130	0.156	0.147	0.128	0.162	0.150	0.125	0.165	0.149	0.118
	April	0.103	0.095	0.081	0.109	0.099	0.081	0.120	0.105	0.081	0.129	0.109	0.080
	May	0.076	0.068	0.053	0.083	0.072	0.054	0.095	0.078	0.054	0.107	0.084	0.054
	June	0.065	0.056	0.041	0.073	0.061	0.042	0.087	0.070	0.043	0.103	0.078	0.045
	July	0.070	0.061	0.046	0.077	0.065	0.046	0.089	0.071	0.047	0.103	0.077	0.046
	August	0.102	0.094	0.075	0.109	0.098	0.075	0.121	0.106	0.075	0.133	0.112	0.073
	September	0.139	0.132	0.116	0.144	0.136	0.115	0.153	0.141	0.113	0.159	0.144	0.109
	October	0.170	0.163	0.153	0.173	0.164	0.151	0.176	0.163	0.145	0.174	0.157	0.134
	November	0.200	0.196	0.190	0.200	0.195	0.188	0.198	0.192	0.182	0.186	0.181	0.170
	December	0.208	0.210	0.203	0.207	0.209	0.201	0.201	0.206	0.194	0.185	0.194	0.180
Queenstown	January	0.224	0.225	0.215	0.224	0.225	0.212	0.219	0.222	0.204	0.204	0.210	0.190
	February	0.202	0.197	0.186	0.205	0.198	0.184	0.206	0.197	0.179	0.199	0.189	0.167
	March	0.168	0.163	0.143	0.173	0.167	0.142	0.181	0.172	0.139	0.185	0.174	0.132
	April	0.125	0.115	0.096	0.132	0.120	0.095	0.144	0.128	0.094	0.156	0.133	0.090
	May	0.081	0.073	0.056	0.088	0.078	0.056	0.100	0.085	0.055	0.112	0.092	0.054
	June	0.070	0.060	0.042	0.078	0.066	0.042	0.092	0.074	0.043	0.107	0.083	0.042
	July	0.079	0.069	0.050	0.087	0.074	0.050	0.102	0.083	0.050	0.117	0.091	0.049
	August	0.107	0.098	0.077	0.115	0.104	0.077	0.128	0.112	0.076	0.142	0.119	0.073
	September	0.151	0.141	0.125	0.157	0.145	0.124	0.167	0.150	0.122	0.174	0.152	0.117
	October	0.190	0.183	0.171	0.194	0.185	0.169	0.198	0.186	0.164	0.195	0.181	0.154
	November	0.219	0.215	0.209	0.220	0.214	0.206	0.216	0.209	0.199	0.204	0.197	0.185
	December	0.227	0.225	0.221	0.226	0.223	0.218	0.220	0.217	0.210	0.203	0.201	0.194

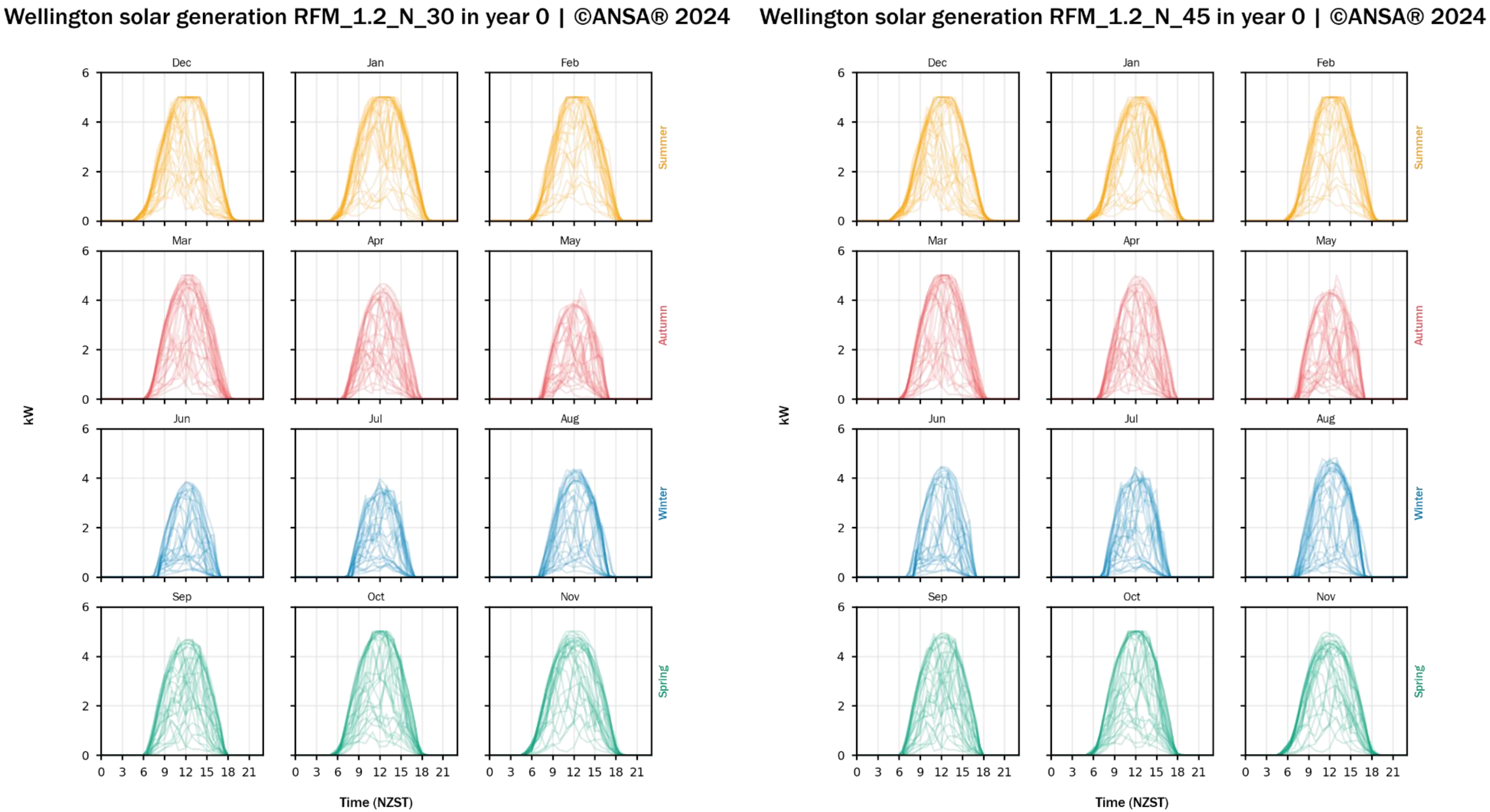


(a)



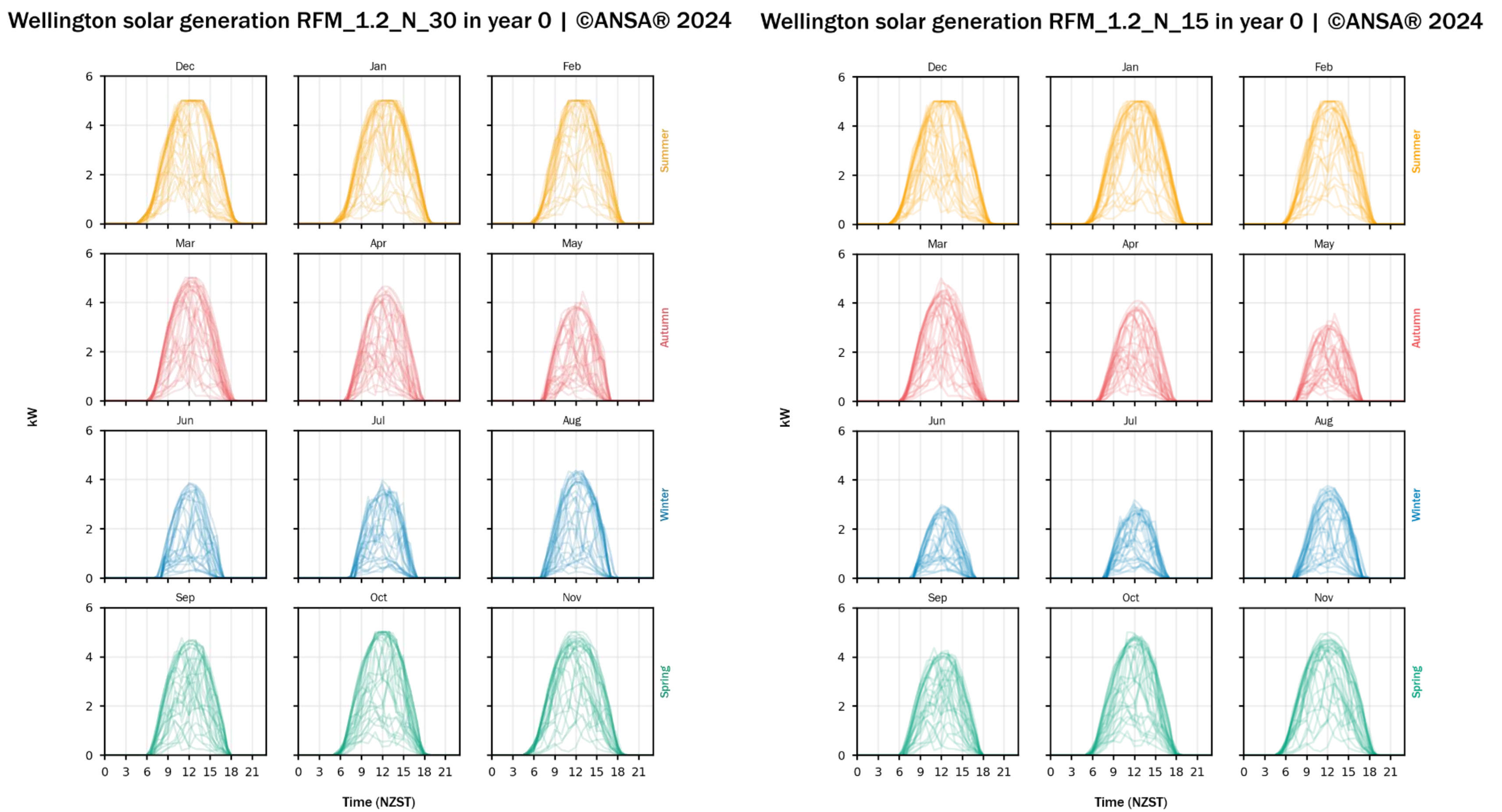
(b)

Figure 4: PV solar generation for Wellington (Petone) mounted on a roof with 30-degree tilt and north facing (monofacial panels), showing the difference between oversizing the DC array capacity by 20% (a) as used throughout the model Base Case, and a DC array matched to the inverter capacity (b) as used in the 'low ILR' sensitivity case. Oversizing the DC array results in the PV system more frequently reaching its AC capacity in summer months and producing higher generation in other months. Year 0 is the same as Year 1, the first year of operation in the model.



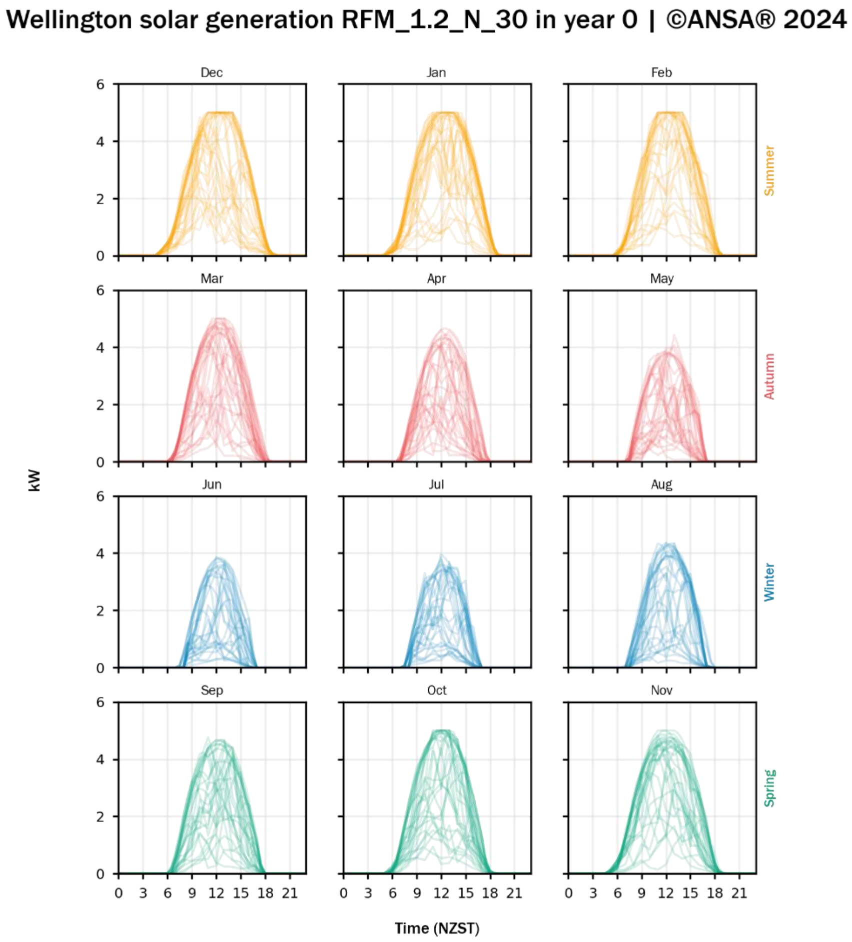
(a) (b)

Figure 5: PV solar generation for Wellington (Petone) mounted on a roof north facing roof (monofacial panels), showing the difference between a 30-degree tilt in (a) as used throughout the model Base Case, and a 45-degree tilt sensitivity case in (b) as used in the '45-degree tilt' sensitivity case. The winter generation with the higher tilt (b) is higher than the lower tilt (a). Year 0 is the same as Year 1, the first year of operation in the model.

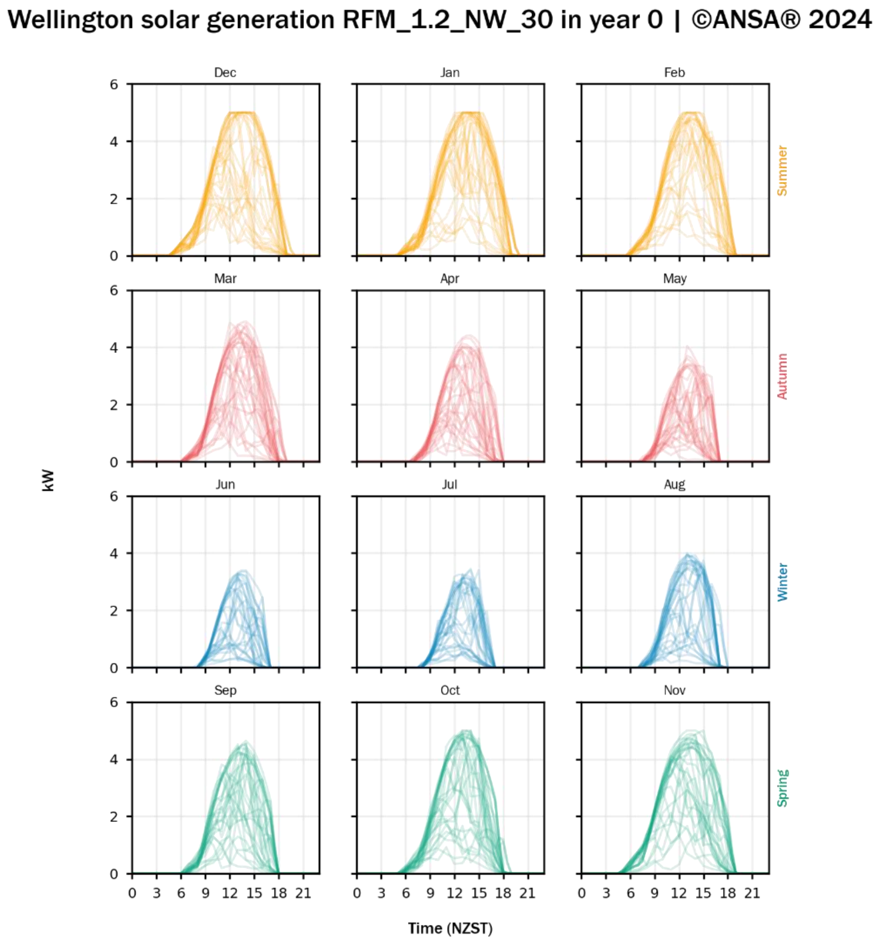


(a) (b)

Figure 6: PV solar generation for Wellington (Petone) mounted on a roof north facing roof (monofacial panels), showing the difference between a 30-degree tilt in (a) as used throughout the model Base Case, and a 15-degree tilt in (b) as used in the '15-degree tilt' sensitivity case. Winter generation with the lower tilt (b) is lower than the higher tilt (a). Year 0 is the same as Year 1, the first year of operation.

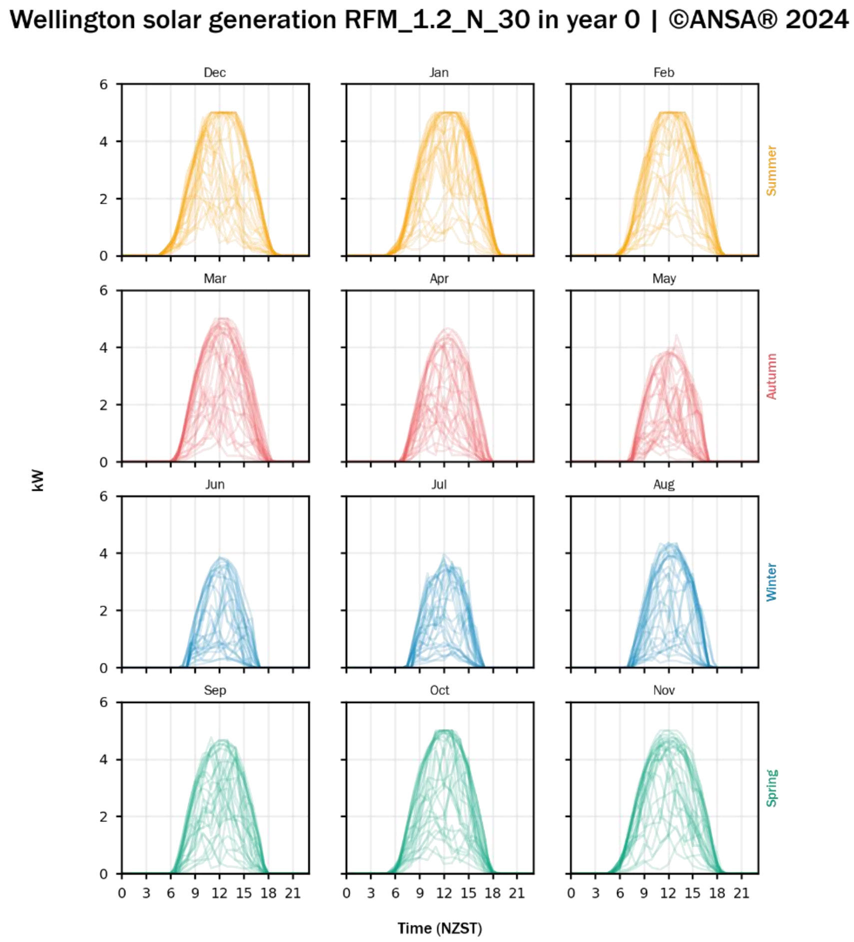


(a)

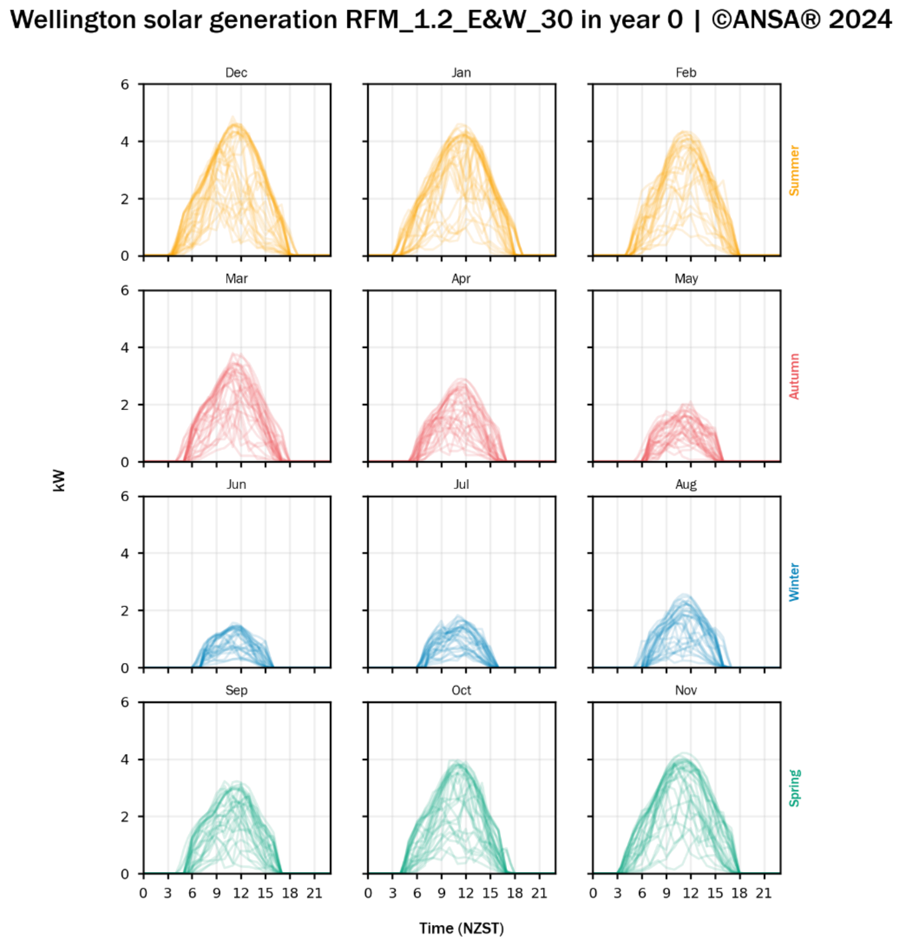


(b)

Figure 7: PV solar generation for Wellington (Petone) mounted on a roof with a 30-degree tilt (monofacial panels), showing the difference between a north facing roof (a) as used throughout the model Base Case, and a northwest facing roof in (b) as used in the 'northwest' sensitivity case. Winter generation is lower with the northwest facing array, and that there is a skew away from the morning towards the latter part of the day. Year 0 is the same as Year 1, the first year of operation.



(a)



(b)

Figure 8: PV solar generation for Wellington (Petone) mounted on a roof with a 30-degree tilt (monofacial panels), showing the difference between a north facing roof (a) as used throughout the model Base Case, and half-east and half-west facing array in (b) as used in the 'half-east and half-west' sensitivity case. Winter generation is substantially lower with the east and west facing array, but generation from this array configuration is slightly higher in the early morning and late afternoon periods. Year 0 is the same as Year 1, the first year of operation.