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Electricity Allocation Factor Assumptions Review

Prepared for the Ministry for the Environment

13th March 2019

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Executive summary

In 2011, the Ministry for the Environment (MFE) assembled an electricity allocation factor (EAF) 'contact group' to develop an EAF recommendation for 2013 onwards. This 2013 EAF was intended to be representative until at least 2017 or until there was a significant change in the market.

The decision on an EAF was informed by modelling performed by Energy Modeling Consultants Ltd and MED officials.

Three different modelling approaches were used: short-run marginal cost (SRMC), long-run marginal cost (LRMC) and Cournot. These compared a series of different 'comparative' scenarios, wherein key values were varied (e.g. coal and gas prices, demand growth, plant new-build and retirement), with 'counterfactual' scenarios, which modelled what might have happened had an emissions trading scheme (ETS), and consequently a price on emissions, not been introduced.

However, in the end, the contact group decided to only use results from the SRMC analysis and selected small a sub-set of scenarios across a limited timescale to use for estimating the EAF.

Previous Concept advice has raised our concerns that this SRMC-only approach has material flaws, but these concerns are not the focus of this report.

Instead, this report:

- compares outturn actual values with the assumed values used in 2011 for the key factors (e.g. CO2 prices, coal and gas prices, demand growth) that drove the calculation of the EAF in the modelled scenarios; and
- determines the likely extent to which the EAF would have been different, had actual values been used in the modelling rather than the assumed values.

Concept's analysis finds that:

- The price of NZU's (i.e. the CO2 price) has, until 2016, been lower than assumed in the comparative scenarios; closer to \$0 than to \$12.50/tCO_2e
    - Lower emissions prices caused the 2011 model to produce lower EAFs, so the effect of using observed emissions prices would have been to reduce the calculated EAFs.
- Gas has been consistently cheaper than the assumed \$7.28/GJ
    - To the (limited) extent that it is possible to assess, it appears that lower gas prices produce lower EAFs within the 2011 SRMC models, so real-world gas prices would have produced a lower EAF than those calculated. This effect is likely due to the models running gas plant more often than coal plant if gas prices are cheaper.
- Coal has, on average, been more expensive than the assumed \$4.50/GJ
    - With no variation in coal prices across scenarios it is not possible to determine the effect of higher than assumed coal prices on the EAF had these prices been used for the 2011 modelling exercise. However, to the extent that the models would have run coal less often than gas plant as a result of these higher coal prices, the effect of these higher coal prices would be likely to have resulted in lower EAFs.
- Huntly units 1 and 2 were retired earlier than expected in the modelling assumptions
    - When earlier Huntly retirement dates are used the 2011 model calculated a higher allocation factor. This suggests that had the observed Huntly retirement dates been used the

EAF would have been higher – although this seems counter-intuitive given that Huntly has the highest emissions factor of any plant.

- Electricity demand has been almost flat, such that total demand is far lower than assumed in any EAF modelling scenario
  - The observed output EAF of the models is positively correlated with input electricity demand, so if actual electricity demand values were used, it would have likely produced an EAF that is lower (potentially materially lower) than the values calculated for the 2011 exercise.
- 555 MW of large fossil fuel generation went offline during the 2013-2017 period
  - It is difficult to determine what effect this would have had on the modelled EAFs as such outcomes were not contemplated.
- Huntly Rankine station has burnt 25% gas, instead of 100% coal
  - Intuitively, this suggests that the EAFs generated by the SRMC model are higher than they would be if the dual-fuelling of the Rankine units had been accounted for; however, it is not possible to determine the potential impact on the EAF with certainty, due to inconsistencies in the model's output

Overall, it appears that, had actual values been used rather than the assumed values used in the 2011 model runs, and if the same limited set of scenarios and years had been used to estimate the EAF, the estimated EAF would have been lower (potentially materially so) than the 0.537 tCO_2/MWh value that came out of the 2011 process.

1 Introduction

In 2011, the Ministry for the Environment (MFE) assembled an electricity allocation factor (EAF) 'contact group' to develop an EAF recommendation for 2013 onwards. This 2013 EAF was intended to be representative until at least 2017 or until there was a significant change in the market.

The decision on an EAF was informed by modelling performed by Energy Modeling Consultants Ltd and MED officials. Three different modelling approaches were tried as part of this process for estimating an EAF:

- Short-run marginal cost (SRMC), wherein the generation fleet mix is determined by long-run marginal cost (LRMC) modelling but the dispatch of generation assets to meet demand is determined by hourly modelling based on the SRMC of generators;
- Cournot modelling, where the generation fleet is again determined by LRMC modelling but the electricity market is modelled using an imperfect competition model which can simulate strategic bidding by generators;
- LRMC, which the generation fleet and electricity prices are based on the long-term costs of building and operating new generation plant over its lifetime.

As part of these three different approaches, many different scenarios were created and tested, relating to such factors as fuel price, demand growth, plant build and retirement, and also CO2 price. Each comparative CO2 price scenario had a related counterfactual scenario with zero CO2 price.[1]

For each year in each scenario the EAF was calculated as: the difference between the electricity price produced by the models in the comparative scenario versus the relevant counterfactual scenario, divided by the CO2 price in the comparative scenario. (Noting that the CO2 price in the counterfactual scenario was zero).

Despite running and producing results for these many different approaches and scenarios, in the end, the contact group decided to only use results from the SRMC modelling to inform development of the EAF. Further, as set out below, only a very small number of scenarios and modelled years were used to arrive at the final EAF number.

Past Concept advice has raised concerns that this SRMC-only approach for determining the EAF has material flaws.[2]

However, the purpose of this report is not to re-visit these concerns but rather to:

- Compare outturn values with the assumed values used in 2011 for key factors (e.g. CO2 prices, coal and gas prices, demand growth) that drove the calculation of the EAF in the modelled scenarios and years used for the estimation of the EAF.
- Indicate the likely extent to which the EAF would have been different had actual values been used *in the SRMC models*[3], rather than the assumed values.

[1] These counterfactual CO2 price scenarios also had different generation mixes due to altered assumptions about plant new-build and retirement.
[2] *"High-level review of approaches for estimating a standard electricity allocation factor (EAF)"*, Concept Consulting, 1/04/2015
[3] i.e. the purpose of this review is not to indicate how these actual values might have resulted in changes to the actual effective EAF in the real world, but rather how the values would affect the EAF calculated using the 2011 modelling framework.

2 Scenarios and assumptions used for the EAF modelling

Table 1 below sets out all the different SRMC scenarios run for the modelling exercise, with the calculated EAFs for each scenario for each year.

The Counterfactual scenarios have zero CO2 price, whereas the CO2 price for the comparative scenario was indicated by the $12.50, $25 or $50 prefix.

Other scenario identifiers are:

- _M, _L, or _H, which signifies medium, low, or high demand growth of 2%, 1.5% or 2.5% per year, respectively;
- the suffix "_Huntly" indicates that Huntly unit 1 is decommissioned in 2016 with unit 2 following in 2020
  - in non-Huntly scenarios units 1 and 2 are decommissioned one (\$12.50/tCO_2e) or three (\$25/tCO_2e) years earlier than this.
- "Shock" scenarios indicate a high demand shock
- "_Coal" scenarios force the commissioning of "Marden C", a large coal generator
- "_Gas" scenarios force the commissioning of an additional Otahuhu gas-fired CCGT, a large baseload generator
- _HG or _LG indicate high or low gas prices, respectively (although medium gas prices were used for the LRMC-based generation mix projections).

Further, the chosen sub-set of scenarios assumed that the electricity market would be in equilibrium and that an economically efficient mix of generation would be built to meet any increase in demand.

For greater details of the assumptions used in each scenario see Appendix A.

However, in the end, only one counterfactual scenario and four comparative scenarios were used by the contact group for estimating the EAF.

The counterfactual scenario was "Counter_M", which assumes medium electricity demand growth; strong renewable growth to meet increased demand; coal prices of $5.50 (new build) or $4.50 (existing generator); lignite prices of $2.50 and that Huntly unit 1 is decommissioned in 2016 with unit 2 following in 2020

The four comparative scenarios were:

- $12.50_M_Huntly
- $25_M_Huntly
- $12.50_M
- $25_M

Further, only the first two or three years of the scenario projections were used by the contact group to calculate the EAF. The cells shaded blue with bold text in Table 1 are those used to estimate the EAF.

Table 1: full set of calculated EAFs from SRMC modelling; those used for estimating the EAF for 2013 onwards are shaded with bold text

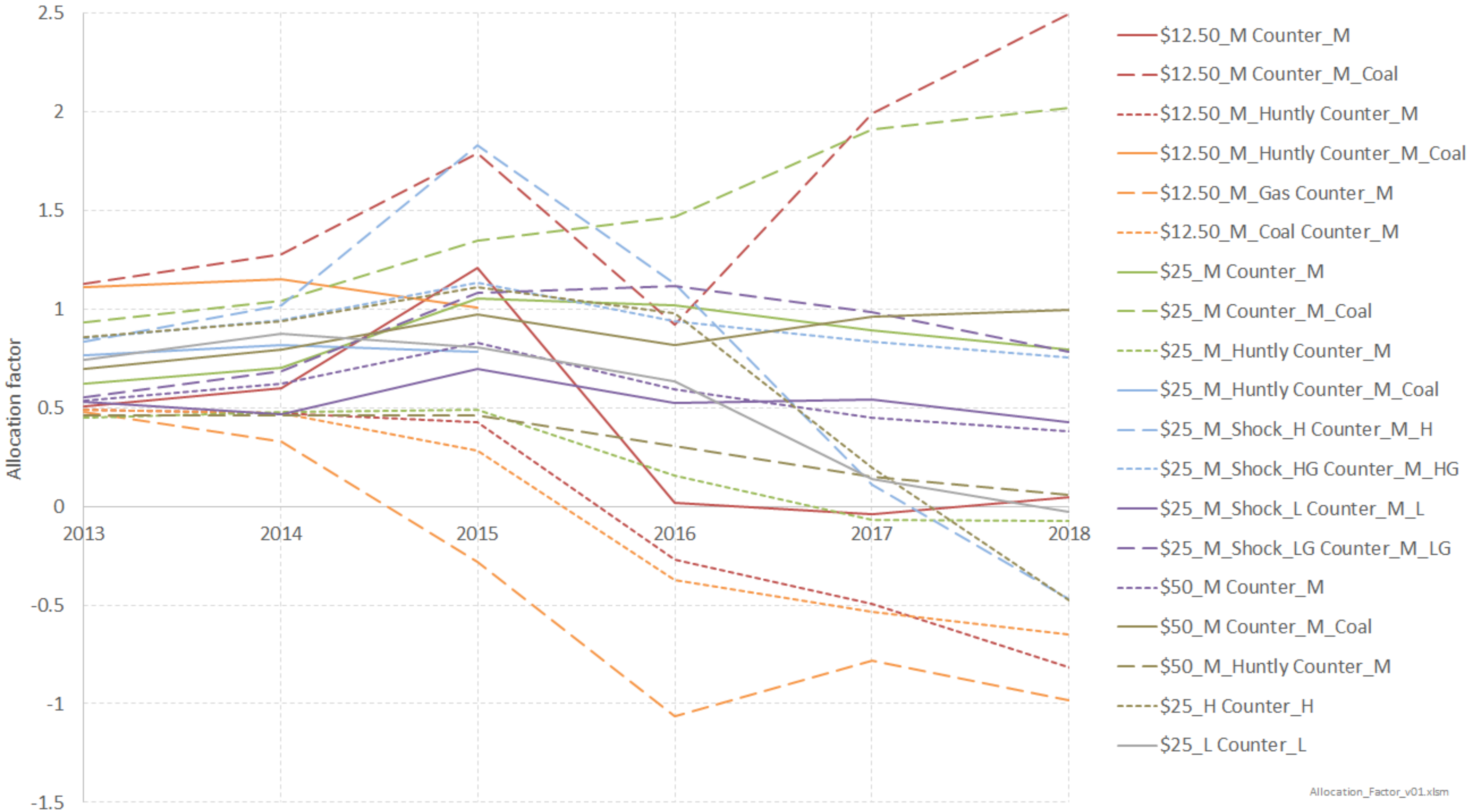
Comparative scenario	Counterfactual scenario	2013	2014	2015	2016	2017	2018
$12.50_M	Counter_M	**0.504**	**0.6**	1.208	0.016	-0.04	0.048
$12.50_M	Counter_M_Coal	1.128	1.28	1.792	0.92	1.992	2.496
$12.50_M_Huntly	Counter_M	**0.488**	**0.472**	**0.424**	-0.272	-0.496	-0.816
$12.50_M_Huntly	Counter_M_Coal	1.112	1.152	1.008			
$12.50_M_Gas	Counter_M	0.48	0.328	-0.28	-1.064	-0.784	-0.984
$12.50_M_Coal	Counter_M	0.488	0.472	0.28	-0.376	-0.536	-0.648
$25_M	Counter_M	**0.62**	**0.7**	1.052	1.016	0.892	0.796
$25_M	Counter_M_Coal	0.932	1.04	1.344	1.468	1.908	2.02
$25_M_Huntly	Counter_M	**0.452**	**0.476**	**0.492**	0.156	-0.068	-0.076
$25_M_Huntly	Counter_M_Coal	0.764	0.816	0.784			
$25_M_Shock_H	Counter_M_H	0.832	1.02	1.832	1.128	0.108	-0.472
$25_M_Shock_HG	Counter_M_HG	0.852	0.944	1.136	0.94	0.836	0.756
$25_M_Shock_L	Counter_M_L	0.528	0.464	0.696	0.524	0.544	0.424
$25_M_Shock_LG	Counter_M_LG	0.552	0.684	1.084	1.116	0.984	0.78
$50_M	Counter_M	0.538	0.622	0.828	0.594	0.452	0.382
$50_M	Counter_M_Coal	0.694	0.792	0.974	0.82	0.96	0.994
$50_M_Huntly	Counter_M	0.458	0.46	0.462	0.308	0.148	0.056
$25_H	Counter_H	0.856	0.936	1.108	0.976	0.196	-0.476
$25_L	Counter_L	0.74	0.872	0.808	0.636	0.136	-0.028

The various EAFs calculated as part of the modelling process are also shown in Figure 1 below.

As can be seen, the EAFs produced by this modelling exercise varied wildly between scenarios, and even between years for a given scenario.

Therefore, the choice of which scenarios and years to use for estimating the EAF would have a major impact on the resulting value.

Figure 1: EAFs calculated from all combinations of scenarios and counterfactuals



3 Comparison between outturn values and assumed values

This section of the report focusses on the following key assumption areas:

- New Zealand Unit (NZU), or CO_2, ‘emissions’ prices
- Fuel prices
  - Gas
  - Coal and lignite
- Electricity demand and price
- Commissioning and retirement of generation plant, especially Huntly Rankine units
- The proportion of coal versus gas burned at the Huntly Rankine power station

It compares outturn values with assumed values for key factors that drove the calculation of the EAF in the subset of modelled scenarios and years used for the estimation of the EAF.

It then indicates the likely extent to which the EAF would have been different had actual outturn values been used, rather than the assumed values.

3.1 Emissions prices

3.1.1 Assumed emissions price

Emissions prices of $0, $12.50, $25 and $50/tCO2e were all modelled, with the $0 scenarios used as counterfactuals.

However, only the $12.50 and $25/t$CO_2$e scenarios were used for informing the decision on an EAF.

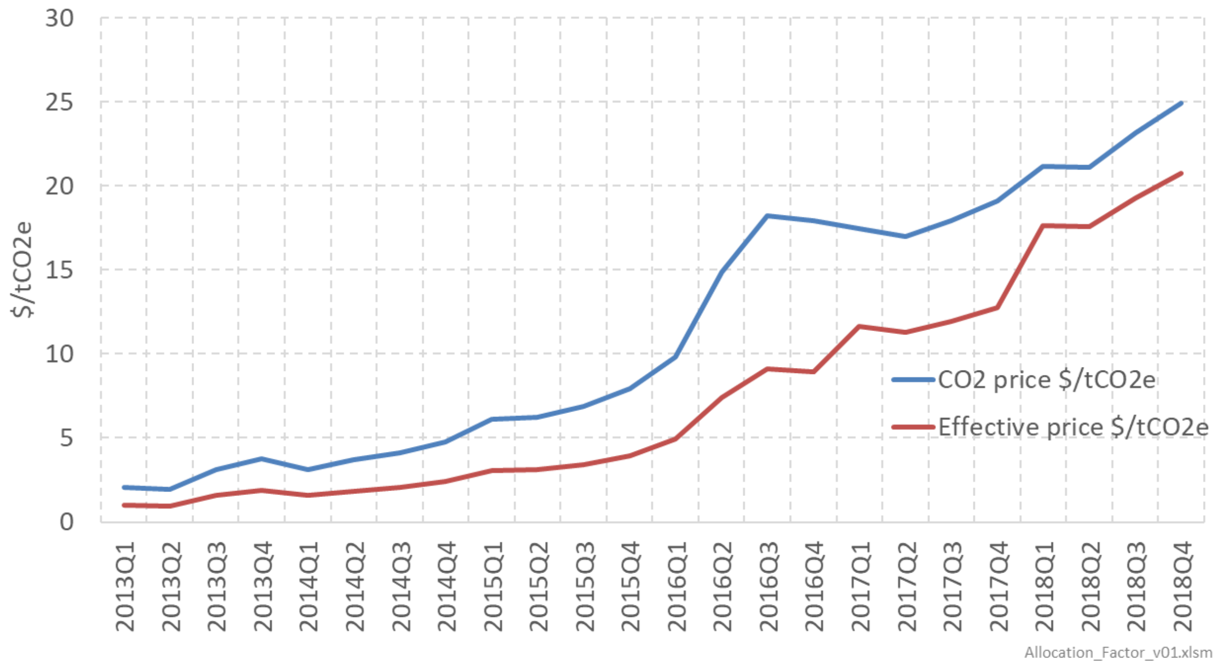
3.1.2 Real-world emissions price

Figure 2 shows how the price of an NZU has changed since 2013, with generally low prices from 2013 until 2016, when there is a sharp and sustained price increase to above $15/t$CO_2$e.

In addition to these changes in the cost of NZUs, there has also been a change in the effective CO2 price faced by electricity generators due to the effect of altering requirements for the number of NZUs required to be surrendered for each tonne of CO2 emitted.

During the early period covered by the modelling, NZU’s could be used “2-for-1”, i.e. each tonne of CO_2e emitted only required the surrender of half an NZU (so if NZUs were priced at $10 each, the effective cost of emissions would be $5/t$CO_2$e). From the beginning of 2017 until the beginning of 2018 each tonne of CO_2e was worth 2/3 of an NZU; from 2018-2019 each tonne of CO_2e was worth 0.833 NZUs. As of 2019, each tonne of emissions is worth one whole NZU.

Figure 2: Quarterly average NZU prices in $/tCO₂e and effective price after the reduced surrender obligation has been applied (2015 prices are estimated)



Note the step-changes at the start of 2017 and again at the start of 2018, caused by changes in the NZU surrender terms.

3.1.3 Implications of differences

Outturn effective CO2 prices averaged over the 6-year period were $7.4/tCO2e. This is below the $12.5/tCO2 used as the low-CO2-price scenario in the modelling.

If only the $12.5/tCO2 SRMC runs were used, the EAF would have been 0.50 not 0.537 tCO2/MWh.

Further, it should be noted that the EAFs from the SRMC modelling declined for lower CO2 prices. Therefore, it appears likely that if runs had been done with $7.5/tCO2 prices, the EAF would have been lower still.

In addition, it should be noted that the EAFs declined for later years in the projection, but these were not used for estimating the EAF. If these later years were included in the average of the two $12.50/tCO2 scenarios used, the EAF would have been 0.18 tCO2/MWh.

In general, *if the same SRMC modelling toolset and scenarios were used*[4] but a lower CO2 price used as an input assumption, the EAF would have been lower.

[4] Noting that the relatively subjective approach used by the contact group to select scenarios used for estimating the EAF means that they may have selected a different subset of scenarios had they been presented with a set with lower CO2 prices

3.2 Gas prices

3.2.1 Assumed natural gas prices

The EAF modelling assumed that wholesale natural gas prices would remain stable at $7.28/GJ (in real 2009$), with the cost of an emissions price added to that.

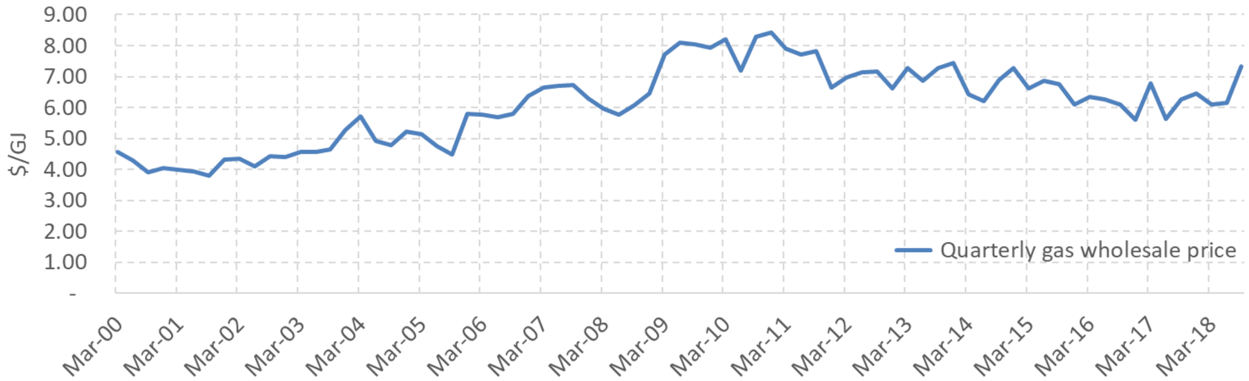
As shown in Figure 3, this was around the same price point seen in 2011-2012, after natural gas prices had fallen from a high price period of over $8/GJ which had lasted since 2009.

Additionally, all the modelled scenarios were constrained by a maximum electricity sector gas usage of 80 PJ/year.

3.2.2 Real-world outcomes

Natural gas prices remained around $7/GJ from 2011 until the end of 2013, when prices began to steadily decline. This decline continued until 2017 when the trend reversed. Throughout 2013-present wholesale gas prices have generally been below $7.28/GJ (in real 2009$) – see Figure 3.

Figure 3: Quarterly average wholesale natural gas prices (in 2009 NZ$/GJ)



Allocation_Factor_v01.xlsm

Quarterly average gas prices dipped as low as $5.59/GJ in the fourth quarter of 2016, and between 2013 and the end of September 2018 the average wholesale gas price was $6.56/GJ – 10% less than that assumed in the modelling.

MBIE's gas statistics show that gas use for electricity generation was significantly below 80 PJ every year between 2013 and 2017; the average amount of gas consumed per year was 44 PJ.

3.2.3 Implications

Since wholesale gas prices were not varied across any of the scenarios used to calculate the EAFs, it is difficult to say conclusively what the effect of using real-world prices would have been on the calculated EAF.

However, the "Shock_HG" and "Shock_LG" scenarios give some indication, with the high gas price scenario having a higher EAF than the low gas price scenario.

Therefore, it would appear likely that if lower gas prices had been used in the modelling, the EAF would have been lower.

3.3 Coal prices

The four comparative scenarios used the following assumptions about coal prices:

- $5.50/GJ for a new coal plant;
- $4.50/GJ for an existing plant, i.e. Huntly;

with extra costs from carbon prices on top of those.

Prices in the counterfactual scenario were as follows:

- $5.50/GJ for a new plant
- $4.50/GJ for an existing plant
- $2.50/GJ for lignite

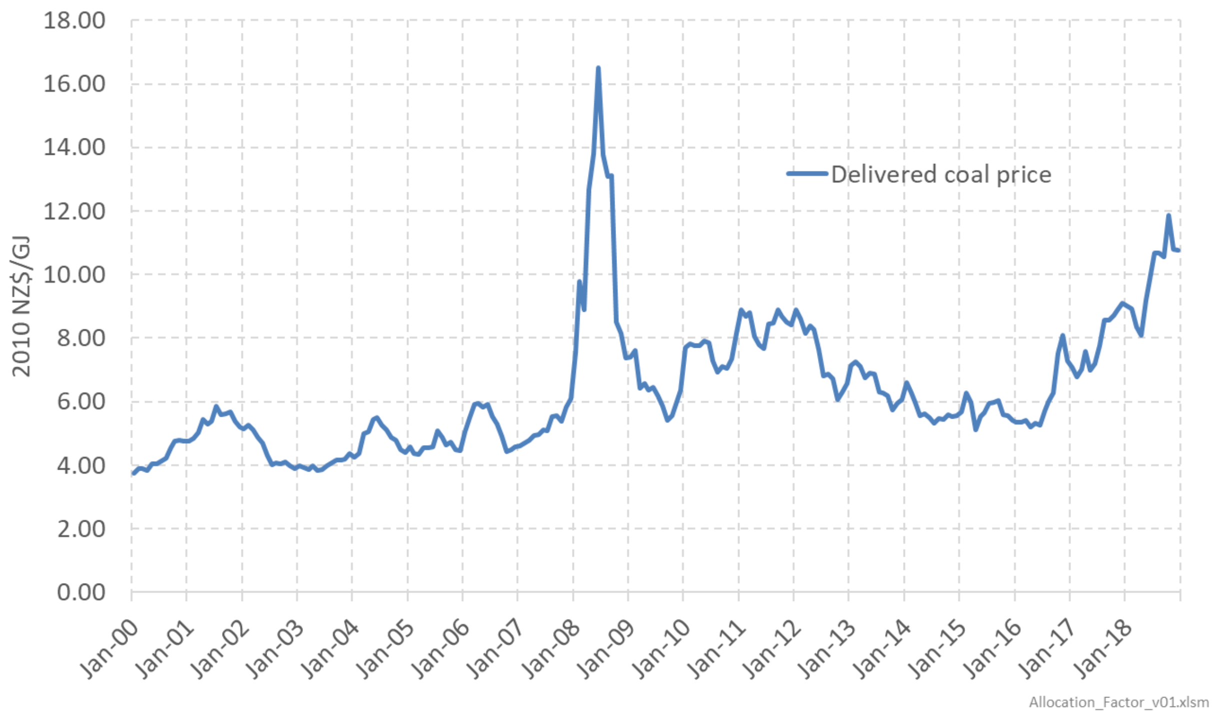
Lignite plants were only available to be commissioned in the counterfactual scenario.

Details of the assumptions used in the full set of SRMC scenarios are reproduced in Appendix A.

3.3.1 Observed prices

As can be seen in Figure 4, between 2011 and 2012 coal prices had largely been stable around $9/GJ, which was significantly higher than prices had been up to 2010 (notwithstanding the price spike around June 2008). By the end of 2012 prices had begun to fall again, however, this trend of decreasing prices reversed in 2016. Coal prices rose sharply starting in the 2nd quarter of 2016 and this price increase has continued until the end of 2018.

Figure 4: Monthly Australian coal prices (price as delivered to an NZ power station)



From the beginning of 2013 until the end of 2017 the average delivered coal price was $6.38/GJ.

3.3.2 Implications

Throughout the 2013-2017 period observed coal prices have been on average $1.88/GJ, or 42%, higher than assumed.

In the real world, higher coal prices would tend to result in lower effects of a carbon price, as coal would tend to be operating for a smaller amount of the time than in a world with low coal prices.

However, for the 2011 modelling, coal prices were the same across all comparative scenarios, except for emissions prices of $25 and $50/tonne where no new coal build was allowed. This makes it difficult to draw comparisons and conclusions relating to what the SRMC models would have calculated as an EAF if these higher coal prices had been used.

3.4 Electricity demand

The SRMC modelling used low, medium and high electricity demand scenarios (based on system operator forecasts) to forecast how electricity demand might change up to 2020. Only medium-demand scenarios were used to help determine the EAF.

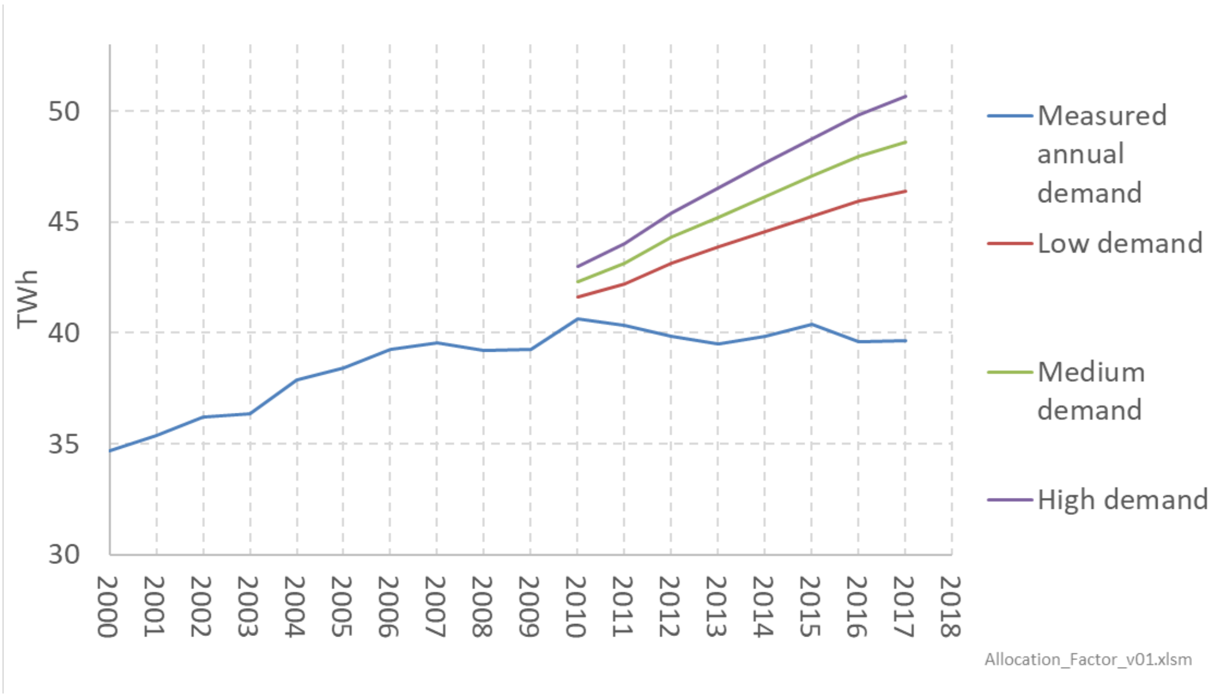
The medium demand scenarios were based on approximately 2% growth per annum from 2010 (a total increase of 6,300 GWh of annual demand by 2017)

3.4.1 Real-world outcome

Until 2010 electricity demand had been following a strong upwards trend, but from 2010 onwards has followed a much flatter trajectory, as shown in Figure 5. Between 2013 and 2017 electricity demand has remained close to 40 TWh per year – i.e. virtually no growth in demand.

Only in the last year has demand started to pick up again.

Figure 5: Annual electricity consumption, real-world and assumed



3.4.2 Implications

Assumed grid demand was the same Medium Demand assumption in all the scenarios used to estimate the EAF.

However, it is possible to qualitatively compare the effects of higher or lower demand on the EAF by using the EAF output from scenarios $25_H and $25_L (see Table 1). The high demand scenario, by 2017, forecasts an extra 4.3 TWh of demand over the low scenario, and the average EAF for the high scenario is 14% higher than for the low scenario.

The low demand scenario, in 2017, assumes an extra 6.7 TWh of demand over the real-world figures (46.4 TWh rather than the observed 39.7 TWh). The difference between actual demand and the assumptions for the medium demand scenarios was greater, a difference of an extra 8.9 TWh by 2017.

It follows that had the EAF models been using actual electricity demand data, then the calculated EAFs would have been lower than the low demand scenarios, and significantly lower than the medium demand scenarios which were used to inform the EAF decision.

3.5 Generation fleet

3.5.1 Huntly retirements

Assumptions

Different scenarios assumed different dates for the retirements of Huntly units 1 and 2, all falling between 2013 and 2020. For the scenarios used in determining the EAF, these dates are set out in Table 2. For details of other scenarios, see Appendix A.

Table 2: assumed retirement dates for Huntly units 1 and 2, by scenario

	Counter_M	$12.50_M	$12.50_M_Huntly	$25_M	$25_M_Huntly
U1	2016	2015	2016	2013	2016
U2	2020	2019	2020	2017	2020

Real world

In reality, one Rankine unit was placed in storage in 2012, with a second unit being put into storage in 2013 (later permanently decommissioned, in 2015). This is far earlier than had been assumed in any of the scenarios used[5], but occurred when carbon prices were less than $5/tCO_2e.

More recently, Genesis has announced intentions to bring the unit placed into storage back into a position that it can be operated again.

This is a strong indication that other factors, not related to the carbon price, influenced the decision to retire the two Huntly units.

The two remaining Rankine units were scheduled for retirement at the end of 2018, but their life has now been extended at least until 2022.

Implications

The _Huntly scenarios, with later retirement dates, consistently produced lower EAFs than their early retirement equivalents. This suggests that if the actual, even earlier, Huntly retirement dates had been used that the EAF would have been pushed higher.

This seems counter-intuitive, given that the early retirement of relatively high-polluting coal-fired generation should lead to a lower EAF. However, as stated above, the purpose of this report is merely to state the likely implications of using different assumptions within the modelling framework used in 2011 for estimating the EAF, rather than commenting on the appropriateness of the modelling framework.

[5] It is even earlier than in the $50/tCO2e scenarios

3.5.2 Other plant new build and retirement

The EAF models had scope to commission over 900 MW of new generation between 2013 and 2019, to meet the expected increase in electricity demand. This was a mix of hydro, wind, solar and various thermal plants.

Some scenarios, those with the suffixes _Coal or _Gas, forced the commissioning of a large new coal or gas plant (Marsden C coal or Otahuhu gas), respectively. However, these weren't included in the sub-set of scenarios used to estimate the EAF.

Real world

In fact, total operating electricity generation capacity as reported by MBIE[6] *declined* by 2% between 2013 and 2017:

- 143 MW of additional geothermal and 67 MW of wind was brought on-line
- However, this was more than offset by the retirement of 555 MW of gas-fired generation.
  - The Otahuhu combined cycle unit ceased generation in September 2015 (380 MW);
  - The Southdown station ceased generation in December 2015 (175 MW);
- Electricity co-generation also declined during this period, by 4%.

Further, neither the Mardesn C coal generator or the extra Otahuhu gas generator have been commissioned.

Some new fossil generation has been committed since 2013: a new 100 MW gas-fired peaker plant is set to be commissioned in Taranaki in 2020[7]; a wind farm of up to 48 turbines has been consented near Waverley, also in Taranaki.

Implications

It is hard to evaluate what the SRMC models would have produced in terms of an EAF if the above real-world values for plant build and retirement had been used.

This is because in many cases the SRMC models came out with quite unusual results. For example, the scenario with forced building of a large new coal-fired station came up with a significantly *lower* EAF than the equivalent scenario which didn't have this forced building of a coal-fired station.

3.6 Proportion of coal vs gas at Huntly Rankine station

Assumptions

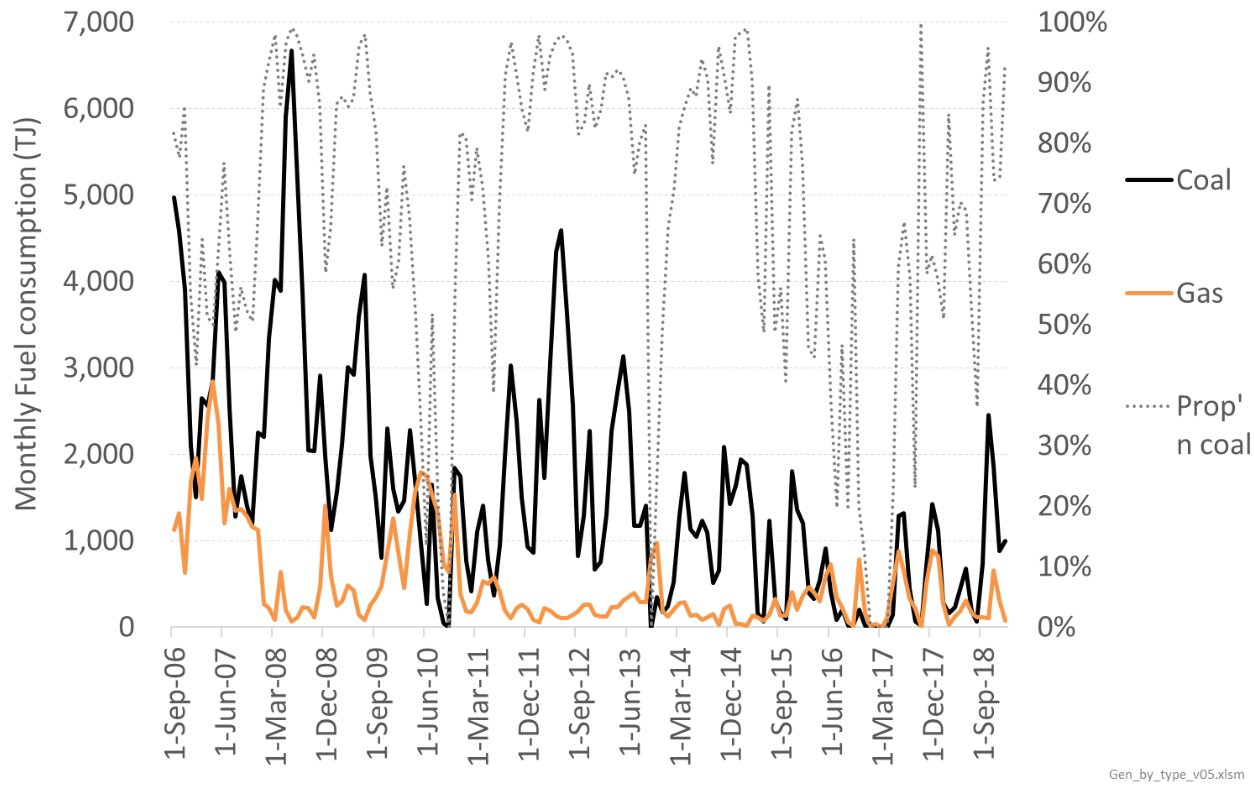
The 2011 modelling assumed that the Huntly Rankine station would only burn coal.

Real world

Figure 6 shows that although coal is the biggest source of fuel for Huntly, gas has also been a material source of fuel: between 20013 and 2018, 25% of generation at Huntly was gas-based.

[6] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/electricity-statistics/ accessed February 2019
[7] https://www.stuff.co.nz/business/105362914/taranakis-new-100-million-natural-gasfired-plant-set-to-open-in-2020

Figure 6: coal energy input into Huntly as a percentage of total energy input (monthly average)



Implications

The reality of Huntly Rankine's dual-fuel nature is to reduce the electricity price effect of an increased cost of carbon – i.e. deliver a lower EAF than if Huntly were forced to burn 100% coal. As it becomes relatively more costly to burn coal, Huntly Rankine would burn a greater proportion of gas, with the electricity price effect being less than if it had been burning 100% coal.

However, given other unusual modelling outcomes (e.g. relating to Huntly retirement), it is hard to estimate what the effect on EAF would have been for the 2011 SRMC modelling had it allowed for Huntly's dual-fuel nature.

4 Conclusions

The following are the major differences between the EAF scenario assumptions and actual outcomes, along with an estimate of how the calculated EAF values would have been different *if the same SRMC modelling toolset, scenarios and years were used*[8]:

- The price of NZU's has, until 2016, been lower than assumed in the comparative scenarios; closer to \$0 than to \$12.50/tCO_2e
  - Lower emissions prices cause the model to produce lower EAFs, so the effect of using observed emissions prices would have been to reduce the calculated EAFs.
- Gas has been consistently cheaper than the assumed \$7.28/GJ
  - To the (limited) extent that it is possible to assess, it appears that lower gas prices produce lower EAFs within the SRMC models, so real-world gas prices would have produced a lower EAF than those calculated. This effect is likely due to the models running gas plant more often than coal plant if gas prices are cheaper.
- Coal has, on average, been more expensive than the assumed \$4.50/GJ
  - With no variation in coal prices across scenarios it is not possible to determine the effect of higher than assumed coal prices on the EAF had these prices been used for the 2011 modelling exercise. However, to the extent that the models would have run coal less often than gas plant as a result of these higher coal prices, the effect of these higher coal prices would be likely to have resulted in lower EAFs.
- Huntly units 1 and 2 were retired earlier than expected in the modelling assumptions
  - When earlier Huntly retirement dates are used the model calculates a higher allocation factor. This suggests that had the observed Huntly retirement dates been used the EAF would have been higher – although as has been noted, this seems counter-intuitive.
- Electricity demand has been almost flat, such that total demand is far lower than assumed in any EAF modelling scenario
  - The observed output EAF of the models is positively correlated with input electricity demand, so if actual electricity demand values were used, it would likely produce an EAF that is lower (potentially materially lower) than the values calculated for the 2011 exercise.
- 555 MW of large fossil fuel generation went offline during the 2013-2017 period
  - It is difficult to determine what effect this would have had on the modelled EAFs as such outcomes were not contemplated
- Huntly Rankine station has burnt 25% gas, instead of 100% coal
  - Intuitively, this suggests that the EAFs generated by the SRMC model are higher than they would be if the dual-fuelling of the Rankine units had been accounted for; however, it is not possible to determine the potential impact on the EAF with certainty, due to inconsistencies in the model's output

Overall, it appears that, had actual values been used rather than the assumed values used in the model runs, and if the same limited set of scenarios and years had been used to estimate the EAF,

[8] Noting that the relatively subjective approach used by the contact group to select scenarios used for estimating the EAF means that they may have selected a different subset of scenarios had they been presented with a different set of results.

the estimated EAF would have been lower (potentially materially so) than the 0.537 tCO_2/MWh value that came out of the 2011 process.

Appendix A. Details of SRMC scenario assumptions

		Counter_L	Counter_M	Counter_H	Counter_M_Coal	$12.50_M	$12.50_M_Huntly	$12.50_M_Coal	$12.50_M_Gas	$25_L	$25_M	$25_H	$25_M_Huntly	$50_M	$50_M_Huntly
	$/tonneCO2e	0	0	0	0	12.5	12.5	12.5	12.5	25	25	25	25	50	50
Huntly units	Unit 1 decommissioned	2016	2016	2017	2016	2015	2016	2015	2015	2013	2013	2014	2016	2012	2016
	Unit 2 decommissioned	2020	2020	2021	2020	2019	2020	2019	2019	2017	2017	2018	2020	2016	2020
Fuel prices	Coal, new plants $/GJ	5.5	5.5	5.5	4.5	4.5	4.5	4.5	4.5	N/A	N/A	N/A	N/A	N/A	N/A
	Coal, existing $/GJ	5.5	4.5	5.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
	Lignite $/GJ	2.5	2.5	2.5	1.8	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Gas $/GJ	7.28	7.28	7.28	7.28	7.28	7.28	7.28	7.28	7.28	7.28	7.28	7.28	7.28	7.28
Diesel price $/GJ	2013	33.62	33.62	33.62	33.62	34.53	34.53	34.53	34.53	35.45	35.45	35.45	35.45	37.27	37.27
	2014	35.97	35.97	35.97	35.97	36.88	36.88	36.88	36.88	37.79	37.79	37.79	37.79	39.62	39.62
	2015	35.99	35.99	35.99	35.99	36.9	36.9	36.9	36.9	37.82	37.82	37.82	37.82	39.64	39.64
	2016	35.92	35.92	35.92	35.92	36.83	36.83	36.83	36.83	37.75	37.75	37.75	37.75	39.57	39.57
	2017	35.85	35.85	35.85	35.85	36.77	36.77	36.77	36.77	37.68	37.68	37.68	37.68	39.5	39.5
	2018	36.2	36.2	36.2	36.2	37.11	37.11	37.11	37.11	38.02	38.02	38.02	38.02	39.85	39.85
	2019	36.21	36.21	36.21	36.21	37.12	37.12	37.12	37.12	38.03	38.03	38.03	38.03	39.86	39.86
	2020	36.22	36.22	36.22	36.22	37.13	37.13	37.13	37.13	38.04	38.04	38.04	38.04	39.87	39.87
Gas consumption	Maximum PJ/year	80	80	80	80	80	80	80	80	80	80	80	80	80	80
New generation commission date	Masden C (320 MW coal)	N/A	N/A	N/A	2010	N/A	N/A	2015	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Otahuhu C (407 MW gas)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2015	N/A	N/A	N/A	N/A	N/A	N/A
New generation earliest commission date	Gas peaker 1 (50 MW)	2012	2012	2012	2012	2012	2012	2012	2012	2012	2012	2012	2012	2012	2012
	Gas peaker 2 (100 MW)	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014
	Gas peaker 3 (160 MW)	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016
	Gas peaker 4 (50 MW)	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018
	Gas peaker 5 (100 MW)	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020
	Diesel peaker 1 (40 MW)	2013	2013	2013	2013	2013	2013	2013	2013	2013	2013	2013	2013	2013	2013
	Diesel peaker 2 (50 MW)	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014
	Diesel peaker 3 (100 MW)	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015
	Diesel peaker 4 (40 MW)	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016
	Diesel peaker 5 (50 MW)	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017
	Diesel peaker 6 (100 MW)	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018
	Diesel peaker 7 (40 MW)	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019
Electricity demand growth	% per year	1.5%	2%	>2%	2%	2%	2%	2%	2%	2%	2%	>2%	2%	2%	2%
Total electricity demand (GWh)	2010	41624	42306	43002	42306	42306	42306	42306	42306	42306	42306	43002	42306	42306	42306
	2011	42218	43130	44036	43130	43130	43130	43130	43130	43130	43130	44036	43130	43130	43130
	2012	43149	44299	45416	44299	44299	44299	44299	44299	44299	44299	45416	44299	44299	44299
	2013	43864	45222	46546	45222	45222	45222	45222	45222	45222	45222	46546	45222	45222	45222
	2014	44581	46160	47670	46160	46160	46160	46160	46160	46160	46160	47670	46160	46160	46160
	2015	45265	47059	48737	47059	47059	47059	47059	47059	47059	47059	48737	47059	47059	47059
	2016	45947	47954	49813	47954	47954	47954	47954	47954	47954	47954	49813	47954	47954	47954
	2017	46381	48596	50660	48596	48596	48596	48596	48596	48596	48596	50660	48596	48596	48596
	2018	46918	49330	51597	49330	49330	49330	49330	49330	49330	49330	51597	49330	49330	49330
	2019	47444	50044	52505	50044	50044	50044	50044	50044	50044	50044	52505	50044	50044	50044
	2020	48064	50902	53561	50902	50902	50902	50902	50902	50902	50902	53561	50902	50902	50902