Modelling of dual-fuel industrial process heat systems

A report to EECA

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1 Introduction

This report describes the approach taken to modelling the potential benefits of an industrial process heat site installing electric process heating equipment (whether an electro boiler or a heat pump) but *retaining* the ability to use the existing combustion boiler(s) – whether fuelled by gas, coal, or biomass.

Having this dual-fuel functionality has both advantages and disadvantages:

- The principal advantages are:
  - The site can switch from electric to gas heat at times of high electricity prices (eg, periods of low renewable generation).
  - The site may be able to avoid some electricity network costs by limiting the extent to which the network needs to invest in network upgrades to accommodate the increased electricity consumption.
- The principal disadvantages are:
  - If the combustion boilers are gas-fired, the site will need to continue to pay for gas pipeline charges, which may not reduce much even though annual gas consumption may decrease significantly.
  - The per-GJ wholesale cost of supplying low-capacity factor combustion fuel (gas, coal, or biomass) is likely to be materially greater than the per-GJ wholesale cost of a steadier supply of such fuel.
  - The site will continue to need to pay for the ongoing maintenance and stay-in-business capex associated with the combustion boiler assets.
  - There will be costs associated with developing the functionality to actively monitor the electricity (and gas) spot market(s) to determine which fuel to use at any point in time.

This report details how the spreadsheet model allows evaluation of each of these items to enable comparison of the likely cost of

- a single-fuel configuration – either entirely the combustion fuel (gas, coal, or biomass) or entirely electricity
- a dual-fuel configuration

2 Description of model

2.1 Structure of model

The spreadsheet model is comprised of a small number of tabs which contain various input assumptions and calculations. Each tab and its purpose is set out in the table below.

Tab	Description
Ctrl	This is where the user specifies the various characterstics of the industrial site (size and pattern of heat load), and various defining parameters for the fuel prices. Further details are set out in section 2.2 below.
Assump	This contains a number of constants and input assumptions. Input assumptions include demand profiles (split between within-year and within-week), and network prices. The demand shape and network price input assumptions have some pre-specified values, but there are also some 'spare' spaces where a user can specify bespoke values that can be called up for use in the model.
ePrice	This contains the database of different electricity price profiles to represent likely patterns of prices in a highly renewable electricity system. As set out in section 2.2, the user specifies in the Ctrl tab which pattern of prices to use. Further information on the derivation of these electricity price profiles is set out in section 0 below.
Calc	This tab undertakes the hour-by-hour calculation of which fuel is cheapest to use when the model is in dual-fuel operation. The model does this evaluation for three different decision timeframes: 1) If the decision can be made on an hour-by-hour basis. 2) If the decision needs to be made on a day-by-day basis, based on which fuel is cheapest on average over the whole day. 3) If the decision needs to be made on a week-by-week basis, based on which fuel is cheapest on average over the whole week. These latter two modes reflect the fact that some industrial sites may not have the flexibility to dynamically switch between fuels on an hour-by-hour basis.
Out	This tab presents the results of the various calculations, highlighting the overall costs and benefits of the different modes of operation, taking into account the fuel costs (including any network costs), plus capital and non-fuel operating costs.
Potential	This tab contains some stand-alone analyses for the potential for dual fuel operation and its impact on the need for fossil generation. It is not used in any part of the model and could be deleted by EECA before releasing the model to external parties.

2.2 Operating the model

The model uses a visual basic macro, so when the model is first opened, the user should specify that macros are enabled.

The user must specify the various characteristics of the site and fuel prices in the Ctrl tab and Assump tab.

This is either achieved using pull-down menus, or through entering values in green-shaded cells. The parameters that need to be specified are:

- Site characteristics
  - The combustion fuel to compare against electricity, selected by a drop-down menu.
  - The peak heat load requirement, and the pattern of demand, the latter selected using drop-down menus. If an appropriate demand pattern is not already specified, the user can input a bespoke demand pattern in one of the 'spare' rows in the Assump tab and give the pattern an appropriate name.
  - The coefficients of performance for the electric and combustion fuel options.
- Network prices
  - This is specified by using a drop-down menu to choose which network prices to choose for the electricity and (if appropriate) the gas option. If a particular set of network prices aren't already saved, the user can input a bespoke set of network prices in the Assump tab and give the network prices an appropriate name.
  - Note: A network price for the combustion fuel only needs to be specified if the combustion fuel is gas, not if it is coal or biomass.
- Fuel prices
  - The user needs to specify the scenario the shape of electricity prices, as well as the time-weighted average electricity price. Section 3.1 sets out more details around the electricity price assumptions.
  - For the combustion fuel, the user needs to specify the baseload fuel price, as well as parameters which will estimate how the $/GJ price of the fuel will increase at progressively lower capacity factors. The exception is for gas where there is a drop-down option which also allows for an alternative approach to be used to calculate the gas price, based on the observed historical relationship between gas prices and electricity prices. Section 3.2 sets out more information about specifying the cost parameters for combustion fuel.
- After specifying the fuel price parameters, and the network prices, the user should hit the button labelled 'Calculate combustion fuel price'. This will perform the iteration described in section 3.2 below which determines the stable capacity factor of operation and associated fuel price, noting there is a circularity between combustion fuel price and capacity factor of operation
- Other non-fuel costs and financial evaluation specifications
  - The user needs to specify the non-fuel electric and combustion fuel appliance costs
  - Additionally, the user needs to specify the parameters to perform the overall present value calculation comparing the single fuel and dual fuel options.

The subsequent output from the model is in the Out tab. This details:

- The optimal operating patterns (expressed in capacity factors for each of the fuels)
- The wholesale and network costs for the different fuels for the different site configurations, split between the different cost components. This is expressed in $k, plus reported on a $/MWh or $/GJ basis for reporting purposes, including variablising fixed costs for such reporting purposes.
- The non-fuel appliance costs of the different options.
- The overall evaluation of the present value of the different cost components for the different configurations.

2.3 Model administration

Only those cells requiring user input can have values changed by the user. Other cells are locked with password protection.

3 Modelling wholesale electricity and combustion fuel prices

A core element of the model is a projection of hourly electricity prices and evaluating how a dual-fuel plant would switch between electricity and the combustion fuel depending on the relative cost of such fuels. This section sets out the derivation of both the electricity and combustion fuel prices.

3.1 Wholesale electricity price modelling

The hourly electricity prices need to capture the full range of likely electricity price outcomes, including variations according to whether it is relatively ‘dry’ or ‘wet’, or whether there are relatively low or high levels of wind or solar generation.

Concept has used its electricity market price forecasting model, ‘ORC’, to project possible price outcomes for future years with higher proportions of renewable energy on the system. For a given future year, ORC evaluates possible price outcomes for 43 different ‘weather years’. These capture the historical *coincident* inflows for hydro concurrently with wind and solar flows and demand for the historical years 1980 to 2022.

However, with 8,760 hours in a year, and a future year being represented by 43 possible weather year, this results in a future year being represented by 376,680 different ‘hours’.

Feeding a data array of this size into an Excel model makes the model excessively large, significantly impacting on performance. Accordingly, a tool was developed which selected sample weeks within the data set that resulted in the price ‘shapes’ within the sample set being close matches to the full data set on the various dimensions of relevance – within-day, within-week, and within-year.[1]

A sample set which only had 22,176 ‘hours’ was chosen, comprised of twelve months with eleven weeks in each month that span the range of likely price outcomes. The size of this data set is just under 6% of the raw data, but two-and-a-half times the number of hours in a calendar year. Testing indicated that this has a sufficient number of samples to result in the price profiles being sufficiently representative of the full data set, while not making the model overly cumbersome.

Three possible wholesale electricity price shapes have been input in the model:

1) Historical wholesale electricity prices for the period January 2000 to August 2024.
2) Projected electricity prices for a future with lower % renewable generation of 91.8% (although still higher than for the historical price series).
3) Projected electricity prices for a future with a higher % renewable generation of 96.8%.

The user can specify which of these price shapes to use, as well as having the ability to specify a time-weighted average price (TWAP) to use, with the model scaling the price shapes to deliver the specified TWAP.

The following charts illustrate the differences between the different price shapes:

[1]The sampling selected 11 representative weeks for each month, with the 11 weeks spanning the range of weekly average price outcomes at equi-distant percentile intervals. The choice of representative weeks, rather than days, was to have realistic week profiles to test situations where the gas versus electricity operation decision could only be undertaken on a week-by-week basis rather than day-by-day or even hour-by-hour.

Figure 1: Average within-week prices

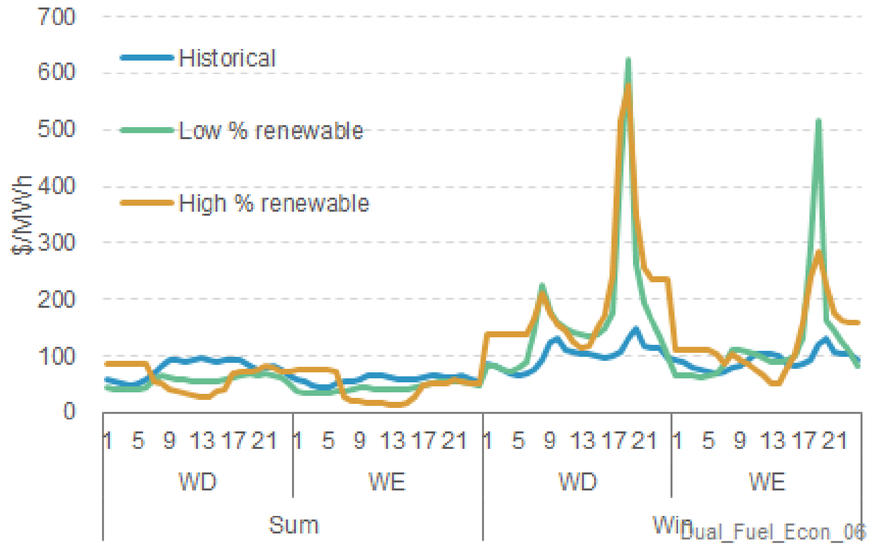


Figure 2: Average monthly prices

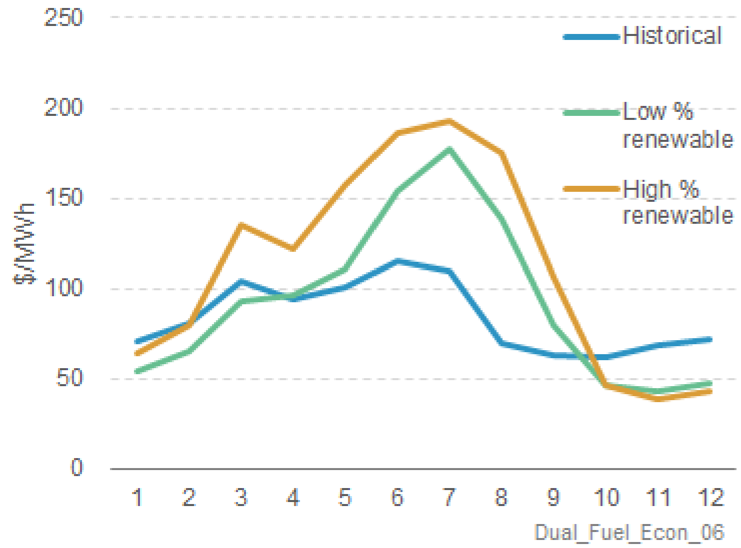


Figure 3: Price duration curve (y-axis stopping at $500/MWh)

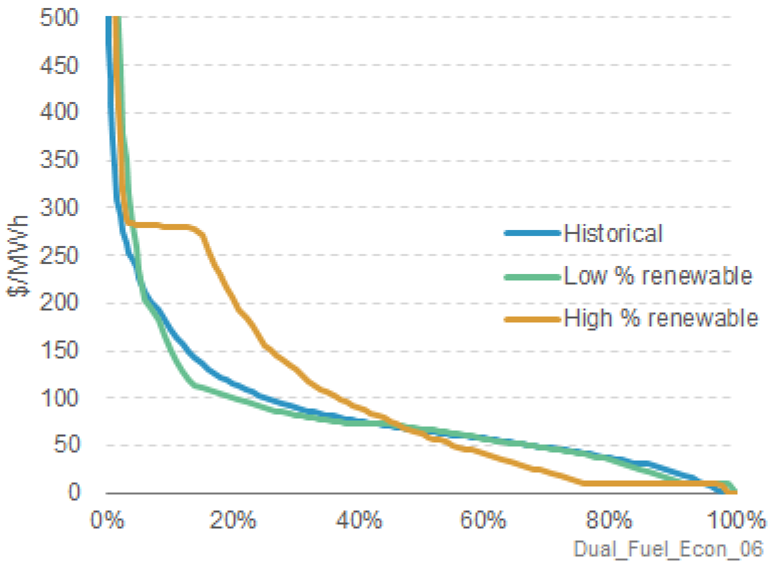
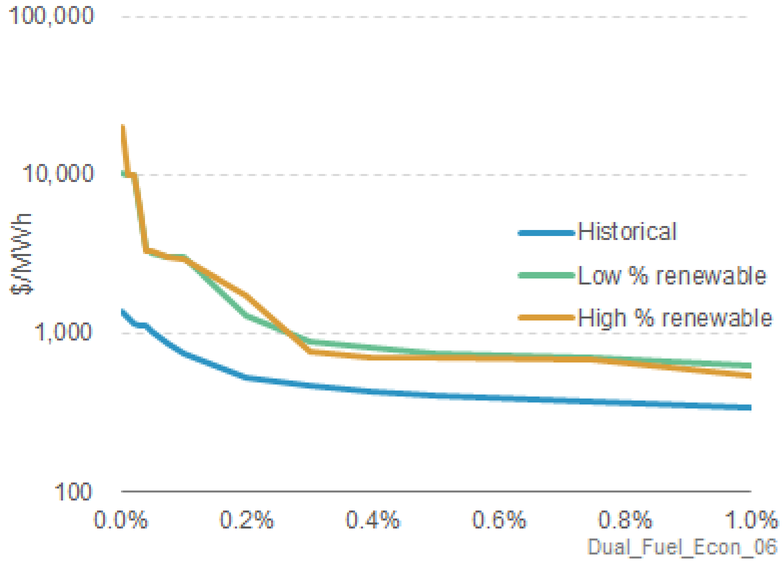


Figure 4: Log-scale price duration curve for top 1% of periods



As the above graphs indicate, as we move to higher % renewables, prices will be characterised by:

- Greater winter/summer price differentials
- Price collapses in summer mid-days for very high% renewable situations – a reversal of the within-day summer shape experienced to-date
- More extreme winter evening peak prices, but less significant rises in morning peak prices. In large part this is due to the charging patterns of EVs, whose uptake is significantly driving the need for wind and solar development.
- Much higher prices at the very top of the price duration curve, but balanced by a far greater proportion of periods of very low

prices, to give a time-weighted average price that is not too different from historical levels.

3.2 The wholesale cost of low capacity factor combustion fuel

For any given modelled hour of operation, the model determines whether it is cheaper to use electricity or the combustion fuel. Accordingly, one user-specified input is the 'baseload' cost of the combustion fuel.

However, dual fuel operation will require a combustion fuel consumption profile that is very different to a baseload one: The same level of peak fuel delivery will be required, but with significant periods of time where no combustion fuel is required. Providing this lower capacity factor fuel will cost more on a $/GJ basis than providing baseload fuel.[2] The lower the capacity factor, the greater the $/GJ cost.

Box 1: Why does lower capacity fuel cost more?

In significant part, this higher per GJ cost is due to the fixed costs of the fuel production facility (gas field, coal mine, or biomass fuel production) that don't vary with the level of production. To reserve the necessary peak fuel delivery capacity from the production facility, the industrial consumer will need to pay a price that allows the producer to recover these fixed costs, but such costs will be spread over a smaller volume of fuel.

In theory, an alternative approach would be for the industrial consumer to procure a steady delivery of the fuel but use a stockpile to manage the variation in usage. However, given the significant year-to-year variation in need, driven by variations in hydrology and the consequent variations in electricity price, the stockpile requirements are large: multiple years' worth. This would also result in higher costs due to the working capital associated with holding a stockpile, plus the cost of the land for the stockpile – land which may not even be available in space-constrained industrial sites. Further, there are question marks over the ability to stockpile biomass for multiple years without suffering material degradation.

The extent to which costs will vary with different levels of fuel capacity factor will be very situation specific, driven by factors such as:

- the extent of variation between fixed and variable costs for the fuel;
- the extent to which the industrial consumer or the fuel producer can use a stockpile to manage some of the variation in demand; and
- the extent to which there may be a liquid market for the fuel that can be accessed on an as-required 'spot' basis.
- the variability of delivery requirement. The greater the degree of randomness to the delivery requirement, the greater the cost of meeting the requirement.

This fact that the $/GJ fuel cost rises as capacity factor falls creates two challenges for this modelling exercise:

1) Estimating the relationship between capacity factor and fuel price; and
2) Determining what capacity factor to use for calculating estimating the combustion fuel price, given that it will also be a function of electricity prices – noting that if the combustion fuel is relatively highly priced compared to electricity the combustion

[2]The capacity factor of fuel consumption is equal to the average daily consumption divided by the peak daily consumption.

fuel capacity factor will be low, and vice versa if the combustion fuel is relatively cheaply priced.

For the first issue, users are asked to provide:

- A baseload $/GJ cost of the combustion fuel (excluding carbon price)
- A $/GJ cost at lower capacity factor. The user can specify which lower capacity factor they wish to use (eg, 20% or 50%). They will need to get a quote from their fuel supplier how much it would cost to provide fuel at this lower capacity factor.

Having provided both these prices, the model produces a curve of prices for all capacity factors.

The second challenge is resolved in the model by the use of a visual basic macro which progressively iterates through multiple steps as follows:

1) Set the initial combustion fuel price to be the baseload price
2) Calculate the resultant operating pattern by comparing the electricity price for each time period with this combustion fuel price to determine which fuel is used. (As set out in XX, this fuel choice decision can be made on an hour-by-hour, day-by-day, or week-by-week basis).
3) Determine the capacity factor of operation across all hours of operation over the modelled period
4) Look up what the combustion fuel price would be at this capacity factor, and input this value as the revised combustion fuel price
5) Repeat steps 2) to 4) until a stable capacity factor of operation is achieved.

It should be noted that this approach will, for some combinations of assumptions, result in an approach which indicates that there should be no combustion fuel used. Ie, the model keeps on moving up the fuel cost curve with ever lower capacity factors until the only stable solution is for no combustion fuel to be used.

3.2.1 An alternative approach for determining the wholesale costs of lower capacity factor gas

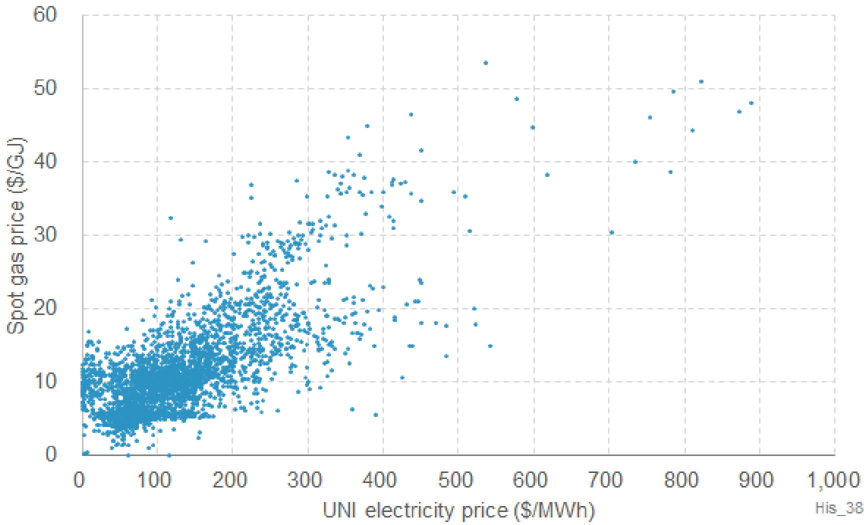
A different approach can be used for gas because of the relationship between gas prices and electricity prices at times of renewable scarcity. In simple terms, the periods when electricity prices are high, are exactly the times when gas-fired generation is most likely to be operating, significantly increasing the price of gas at such times.

Accordingly, if an exogenously specified gas price assumption were to be used – both baseload price and relationship between price and capacity factor – there is a risk that the gas prices would be inconsistent with the electricity prices. This risk does not exist for the solid fuels, as there is not the same relationship between coal or biomass prices and electricity.

To address this issue, analysis was undertaken of historical electricity and gas spot prices to infer a relationship between electricity prices and gas prices and use this relationship to derive likely wholesale gas prices for the scenarios of future electricity prices. This approach may result in gas prices that are more internally consistent with the scenarios of future electricity prices.

Figure 5 plots daily average electricity prices for the upper-north island (ie, at the Otahuhu node) and daily spot (carbon-inclusive) gas prices from the emsTradepoint gas trading platform.

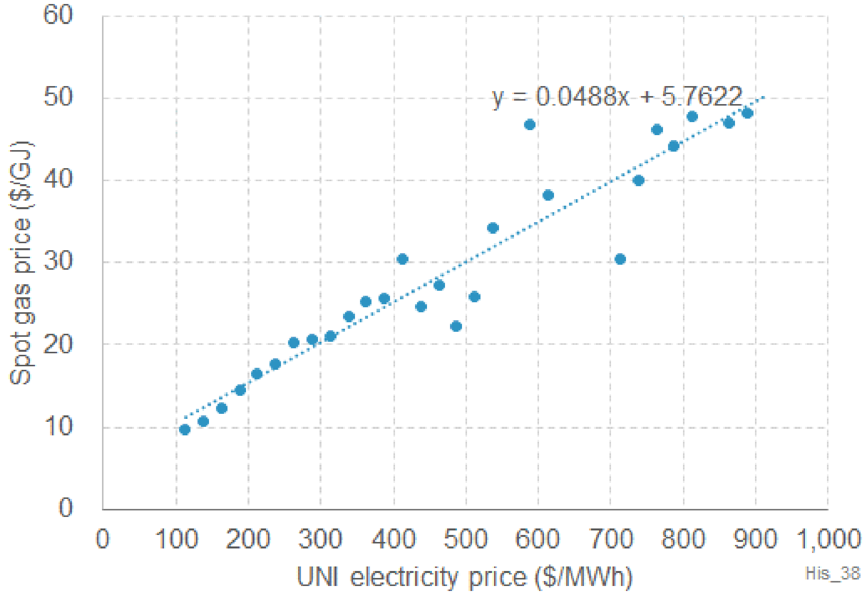
Figure 5: Daily average electricity prices and carbon-inclusive gas prices from Jan-16 to Sep-24



As can be seen there is a strong positive correlation between periods of high electricity prices and high gas prices.

To infer an equation that broadly describes that relationship, Figure 6 below shows the average gas price for electricity price 'bins'. Eg, the lowest point shows the average spot gas price for days when electricity prices were between $100 and $125/MWh, the next point is the average for days when electricity prices were between $125 and $150/MWh, and so on.

Figure 6: Average carbon-inclusive gas price for electricity price intervals during Jan-16 to Sep-24



The equation shown as the best-fit line for the plot is used to estimate the likely gas price for any given electricity price if this gas price option is used. However, it should be noted that the resultant average gas price from this approach delivers average gas prices for the industrial facility that are lower than those currently being experienced in the market. This potentially indicates that the historical relationship between gas and electricity prices is not a reasonable reflection of the new relationships, given change in circumstances for the gas market: a gas deliverability deficit, declining gas reserves, and the likely exit of Methanex which has been a key provider of flexible gas.

Accordingly, the option to use the standard, by assumption, approach to estimate the price of gas at lower capacity factors of operation is also available.