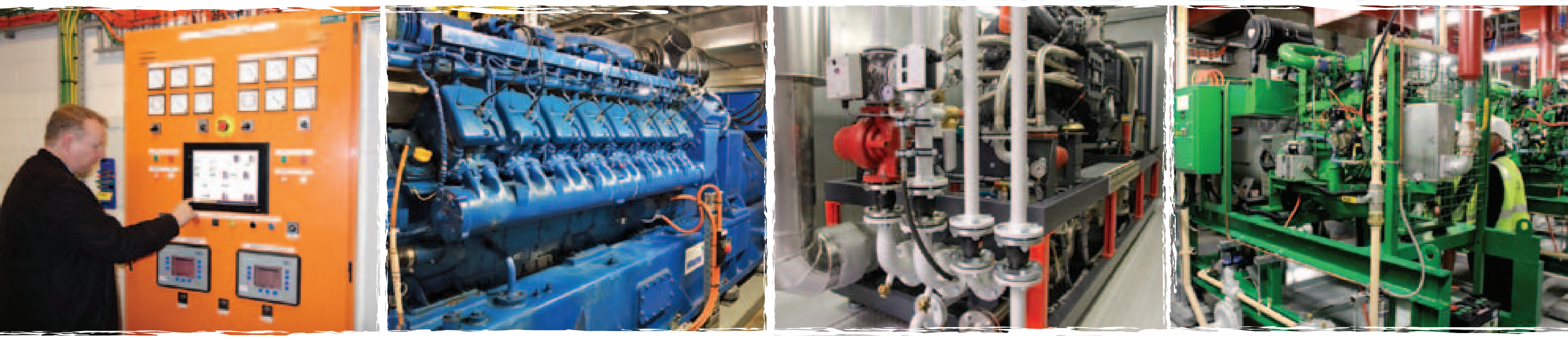
Office of Environment & Heritage

ENERGY SAVER

Cogeneration feasibility guide



environment.nsw.gov.au/business

Published by:

Office of Environment and Heritage NSW
59 Goulburn Street, Sydney NSW 2000
PO Box A290, Sydney South NSW 1232
Phone: (02) 9995 5000 (switchboard)
Phone: 131 555 (environment information and publications requests)
Phone: 1300 361 967 (national parks, climate change and energy efficiency information, and publications requests)
Fax: (02) 9995 5999
TTY: (02) 9211 4723
Email: info@environment.nsw.gov.au
Website: www.environment.nsw.gov.au

Report pollution and environmental incidents
Environment Line: 131 555 (NSW only) or info@environment.nsw.gov.au
See also www.environment.nsw.gov.au

ISBN 978 1 74359 238 0
OEH 2014/0685
September 2014

Table of contents

1 Executive summary

Cogeneration, otherwise known as combined heat and power (CHP), is the simultaneous production of electricity and heat from a single fuel source, commonly natural gas. Trigeneration is an extension of cogeneration which involves the simultaneous production of electricity, heating and cooling.

These systems recover the heat normally lost in traditional grid electricity generation and use it for heating, cooling, dehumidification and other processes. An efficient on-site cogeneration plant can significantly reduce energy costs and carbon emissions. Cogeneration is not a single technology, but an integrated energy system that can be adapted to the needs of the energy end user. Cogeneration can use a variety of fuels to provide reliable electricity, mechanical power and thermal energy. This guide will help you to assess the benefits and risks of a cogeneration system in your facility.

The benefits of cogeneration

Using natural gas cogeneration to generate electricity on-site has two main benefits. Natural gas is currently a much cheaper energy source than grid electricity and can reduce primary energy costs by up to 60 per cent. Using natural gas produces approximately half as much carbon dioxide (CO_2) as coal-powered grid electricity – greenhouse gas (GHG) emissions can be reduced by 50–66 per cent with cogeneration.

The key benefits of cogeneration:

- reduced primary energy costs by up to 60 per cent
- reduced carbon emissions by up to 66 per cent
- increased security of energy supply
- increased fuel efficiency
- improved environmental ratings (NABERS and Green Star).

Will cogeneration work for me?

Each organisation has a unique energy and operational profile and this guide is designed to help you decide if cogeneration will work for you. Facilities that are most likely to benefit from cogeneration are those that use large quantities of thermal load (hot water, heat, steam or chilling) and electricity simultaneously. Examples include hospitals; food and beverage processors; chemicals and plastics producers; pulp, paper and fibreboard manufacturers; metals processors; textile producers and data centres. With careful consideration, cogeneration may also be viable in hotels and shopping centres; universities and TAFEs; large commercial buildings and aquatic centres.

There are many factors that will determine if cogeneration is the right fit for you. In general, cogeneration projects are more likely to be successful at sites with:

- significant and simultaneous need for thermal energy and electrical power over 150 kilowatts (kW)
- thermal requirements that are similar or greater than electrical loads
- constant loads and long operating hours
- electricity costs per unit higher than natural gas costs per unit
- Access to a 'free' energy source, such as biogas or biomass.

This guide will help you to decide if cogeneration is suitable for your site and guide you through all of the different aspects you need to consider. We've included an initial cogeneration viability checklist (Figure 11 page 18) to help you get started.

As a guide, cogeneration may be financially beneficial if more than 60 per cent of the available thermal energy from the cogeneration system can be used on an annual basis. If the cogeneration system only operates for less than 3300 hours per year, then financial returns may be low. The average commercial office building operates for approximately 3080 hours per year (based on 6 am–8 pm, 220 days per year), so making an attractive business case can be difficult for most office buildings.

What does it cost?

Cogeneration and trigeneration can be relatively complex and capital intensive systems. Capital costs range from around $150,000 for small scale systems to millions of dollars for large scale systems. These projects can have significant returns, especially when considered over the life of the plant (around 20 years). Simple payback typically range from two to ten years.

There are number of potential risks that should be considered if you are planning to implement a cogeneration system. Cheaper and more efficient energy upgrades may be more suitable to your situation and it is important to investigate your options carefully. Maintenance and operation costs and requirements may be higher with cogeneration and it can be difficult to find skilled operational and maintenance people. Achieving regulatory and environmental approvals can also cost a considerable amount of time and money. Poorly designed systems can lead to reliability issues and power outages.

Some common problems that affect the success of cogeneration projects are listed below – detailed information on how to overcome these is provided in this guide.

- not accounting for the planned impact of energy efficiency projects on the facility loads
- inaccurate or incomplete thermal and electrical load data
- not accounting for sudden load changes
- overestimation of the cost savings attributed to demand charge reductions
- electrical connection does not meet network service provider requirements.

This guide is designed to help organisations increase their knowledge about cogeneration systems, investigate the potential of cogeneration for their facility and ultimately increase the number of efficient cogeneration projects operating in Australia.

The Office of Environment and Heritage offers training courses designed to help businesses determine whether a cogeneration system is the best technology for their organisation. This training consists of an introductory course designed for decision-makers and a technical course for specialists conducting cogeneration pre-feasibility assessments. For more information on cogeneration training visit
www.environment.nsw.gov.au/business/cogen-training.htm

2 Introduction

2.1 Purpose and background

The purpose of the *Energy Saver Cogeneration Feasibility Guide* is to provide:

- practical information about on-site cogeneration projects
- a detailed step-by-step guide to evaluate the preliminary financial viability of an on-site cogeneration system.

This guide is intended for asset/facility managers and engineers. Sufficient detail has been included to enable non-engineering personnel to use this guide effectively. This guide is meant for sizing small to medium on-site cogeneration systems (up to 5 MW).

This guide does not consider the feasibility of offsite/district heating or cooling networks or bottoming cycle types of cogeneration.

The need for this guide was identified in *Cogeneration in NSW*, a 2008 report by the Institute for Sustainable Futures which recommended that 'a comprehensive guide for potential adopters of cogeneration ... practical issues and process that an organisation needs to go through to make a decision on investing' should be produced.

This guide aims to bridge an information gap and reduce transaction costs for organisations wishing to investigate the potential of this technology. An efficient on-site cogeneration project can significantly reduce an organisation's energy costs and carbon emissions.

The development of a cogeneration project from the initial idea until the plant is in operation has three distinct phases: pre-investment, investment and operating (Figure 1).

This guide provides a tool for preliminary (or pre-feasibility) cogeneration assessments conducted in the pre-investment phase. However, due to its complex technical nature and large capital investment, further investigations, such as a full engineering assessment or design, are commonly required. These investigations usually require an external consultant and can be quite expensive. Site personnel can use this guide to either rule out cogeneration or help to justify the cost of a full analysis.

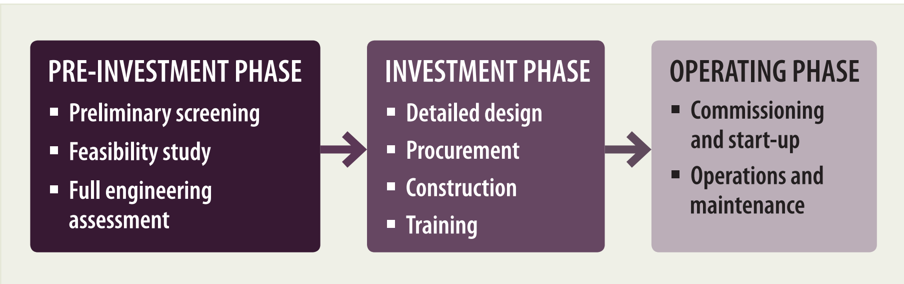


Figure 1: Cogeneration project cycle

2.2 How to use the guide

The guide can be read from start to finish or you can jump to any section of interest. See Figure 2 for a guide outline. There are three distinct parts to the document.

General information and advice

For general information and to get an initial understanding of cogeneration and how it is applied, refer to sections 1–3. These sections cover general site characteristics that are required to make cogeneration favourable, along with some key common mistakes and how to avoid them. It also includes a viability checklist that can help to determine if cogeneration warrants further investigation.

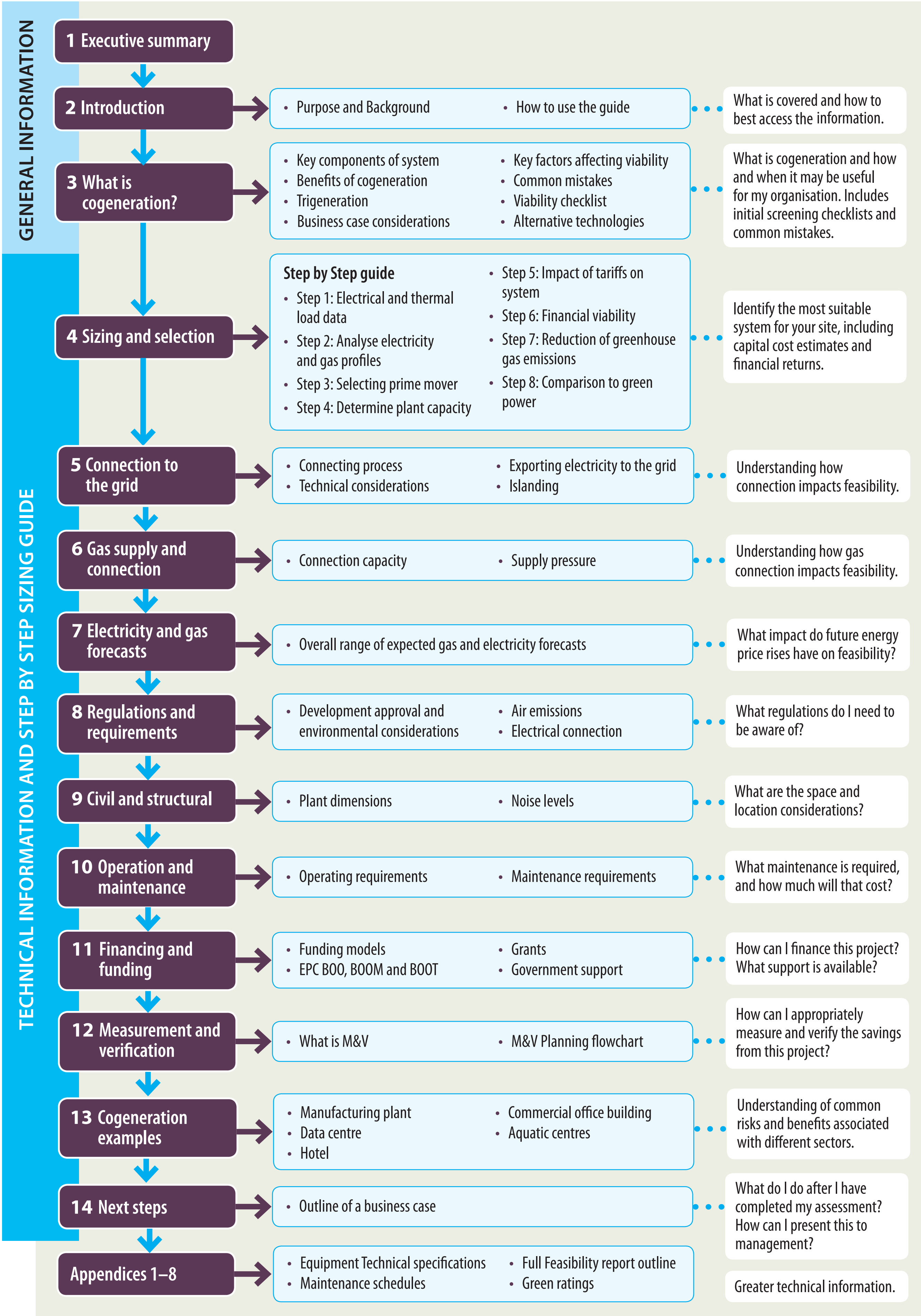
A technical step-by-step detailed guide to conducting a pre-feasibility study

A more detailed technical review is covered in sections 4–14. This includes information on how to select and size the right system which is arguably the most important aspect of viability. This is illustrated through a worked example of a manufacturer, although the information is applicable to all types of sites and circumstances. Further information on other critical aspects, including connection, regulations, operation and maintenance is also provided.

Additional technical information including specifications

Appendices 1–8 provide more detailed information on all of the aspects covered in the guide that affect feasibility and includes brief specifications for different plant equipment.

Figure 2: Guide outline



3 What is cogeneration?

Cogeneration, otherwise known as combined heat and power (CHP), is the simultaneous production of electricity and heat from a single fuel source. Electricity production generates a significant amount of heat which is normally not captured or used in any way. A cogeneration system recovers the heat for use in heating, cooling, dehumidification and other processes.

Cogeneration is not a single technology, but an integrated energy system that can be adapted to the needs of the energy end user. Cogeneration can use a variety of fuels to provide reliable electricity, mechanical power and thermal energy. Cogeneration units predominantly use natural gas as their fuel source, which has a significantly lower emissions factor than conventional grid electricity, which generally uses coal. The traditional method of supplying energy to a site uses both grid-supplied electricity and a separate fuel source for thermal demands (Figure 3). In a cogeneration system, energy is supplied with a single fuel source and waste heat is captured and used (Figure 4). As a result, cogeneration can generate substantial savings for the end user.

Figure 3: Traditional generation for heating cooling and electricity

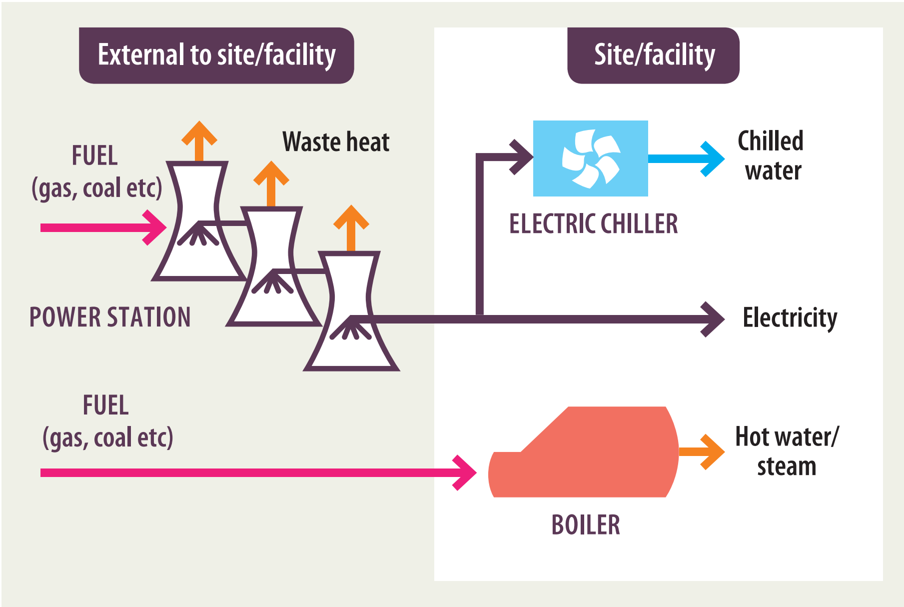
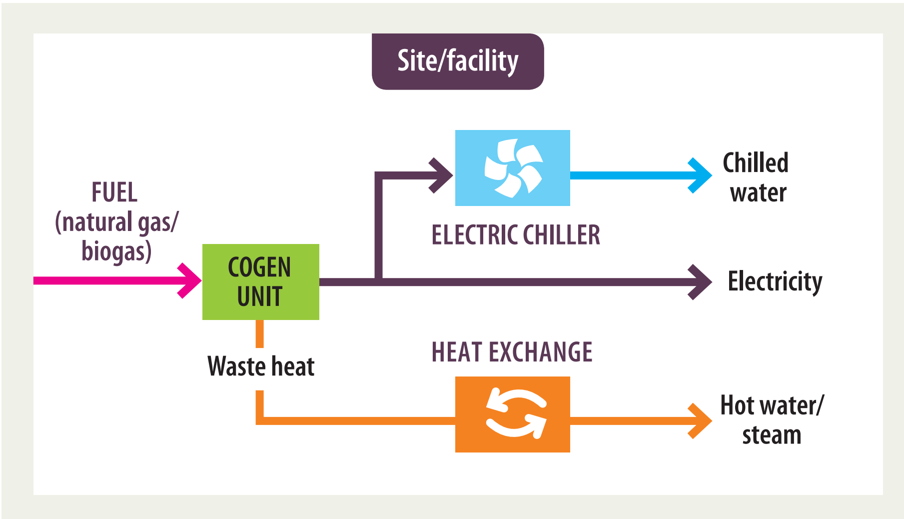


Figure 4: Cogeneration system



3.1 Benefits of cogeneration

Cogeneration is a proven technology and has been recognised worldwide as a cleaner alternative to traditional centralised generation. If a cogeneration system is optimised, then significant environmental, financial and operational benefits arise (Figure 5).

The carbon price impact is greater on grid electricity than on natural gas, so purchasing less grid electricity will reduce exposure to a carbon price.

Environmental

- Improved fuel efficiency – reducing the amount of fuel needed to provide energy means that fewer resources are required.
- Reduced CO_2 emissions – through reducing fuel use and replacing coal with natural gas, which has significantly lower CO_2 content.
- Reduced transmission losses – reducing the distance from generation to use.

Financial

- Reduced primary energy costs – natural gas is generally cheaper than grid-purchased electricity.
- Flexible procurement – more choice of which fuel to purchase for use.
- Improved National Australian Built Environment Rating System (NABERS) and Green Star ratings – an improved rating can have a financial benefit in rental returns and improved asset values.
- Reduced network upgrade costs – with a reduced need to pay for expensive electricity network upgrades if site energy demand increases.
- Reduced impact of a carbon price – the carbon price impact is greater on grid electriciry than on natural gas, so purchasing less grid electricity will reduce exposure to a carbon price.

Operational

- Increased thermal supply choices – this can lead to operational improvements.

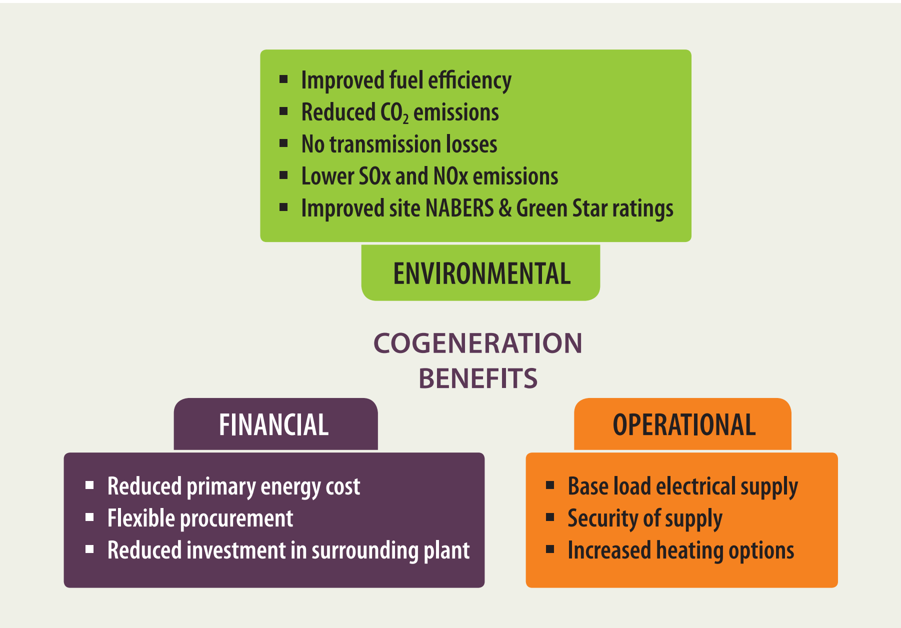


Figure 5: Benefits of cogeneration

3.2 How does cogeneration improve fuel efficiency?

Thermal utilisation is the amount of waste heat captured from a cogeneration system and put to use in other processes, such as providing hot water or space heating. High thermal utilisation is critical to achieving efficiency improvements and the best financial, environmental and operational outcomes.

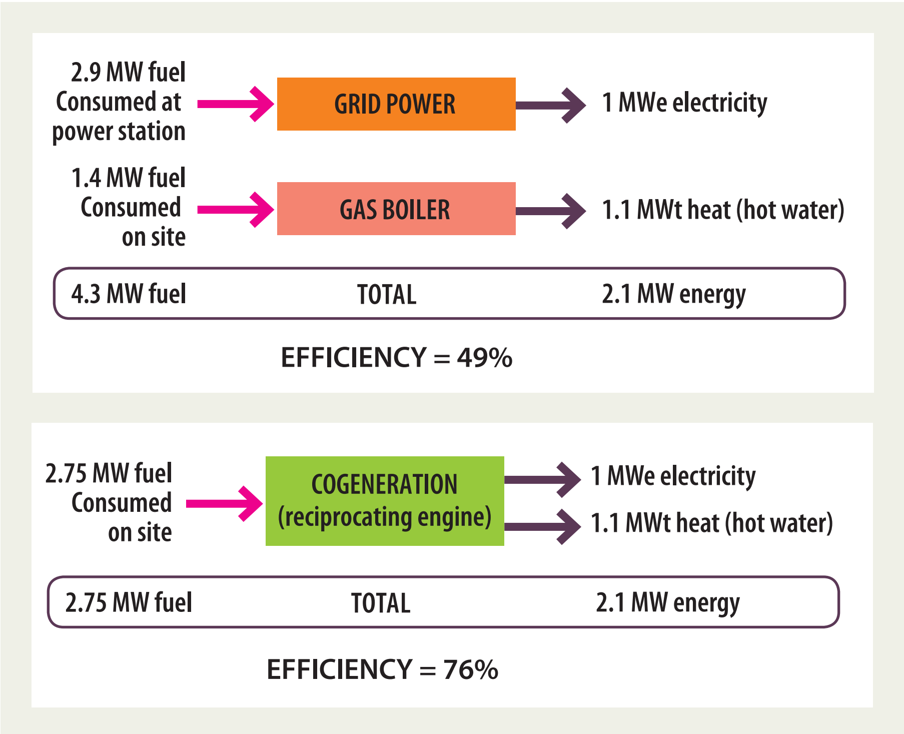
Cogeneration systems increase fuel efficiency in two main ways:

- traditional centralised grid-supplied electricity is not as fuel efficient as cogeneration because the majority of the energy created is lost (wasted) as heat to the atmosphere. Cogeneration systems capture and use the waste heat. This increases the amount of total useful energy received from each unit of input
- cogeneration reduces transmission and distribution losses inherent in grid electricity systems because there is no need to transport electricity across large distances.

The overall efficiency of producing both heat and power using cogeneration is typically 76 per cent for (Figure 6) compared to the conventional separate production of power and heat of 49 per cent.

It is very important to note that the waste heat needs to be captured and used to achieve the substantial efficiency increase. This is referred to as thermal utilisation. If only half of the heat was used, then the cogeneration efficiency in Figure 6 would be reduced to 56 per cent. This highlights the importance of waste heat utilisation to the overall value of the system.

Figure 6: Conventional heat and power efficiency compared to a one megawatt (MW) cogeneration reciprocating engine[1]



1 Assumptions: grid boiler generation efficiency of 36%; high heating value (HHV) less 5% transmission and distribution losses; gas efficiency of 80% (HHV); cogeneration reciprocating engine generator electrical efficiency of 36.4% (HHV); and waste heat recovered from reciprocating engine cooling and exhaust is fully utilised.

3.3 Components of a cogeneration system

Cogeneration systems can be broken down into two basic power cycles types: topping and bottoming cycles.

This guide focuses on helping users that are considering topping cycle cogeneration, as bottoming cycles are most relevant to heavy industry, where the benefits and risks of cogeneration are already well known.

In a topping cycle the input energy (fuel) is used first to generate power and then waste heat is captured from this generation and used to provide thermal energy for use in site processes (Figure 7). This cycle is also referred to as a combined cycle arrangement. Turbine generators, steam turbine generators and reciprocating internal combustion engine generators with heat exchangers are examples of power topping cycles.

In the bottoming cycle, the generation sequence is reversed. High temperature heat is first generated to be used in a process such as steel or concrete manufacture and then the heat from the process is captured and used to generate electricity. This is generally through a steam or organic Rankine cycle (ORC).

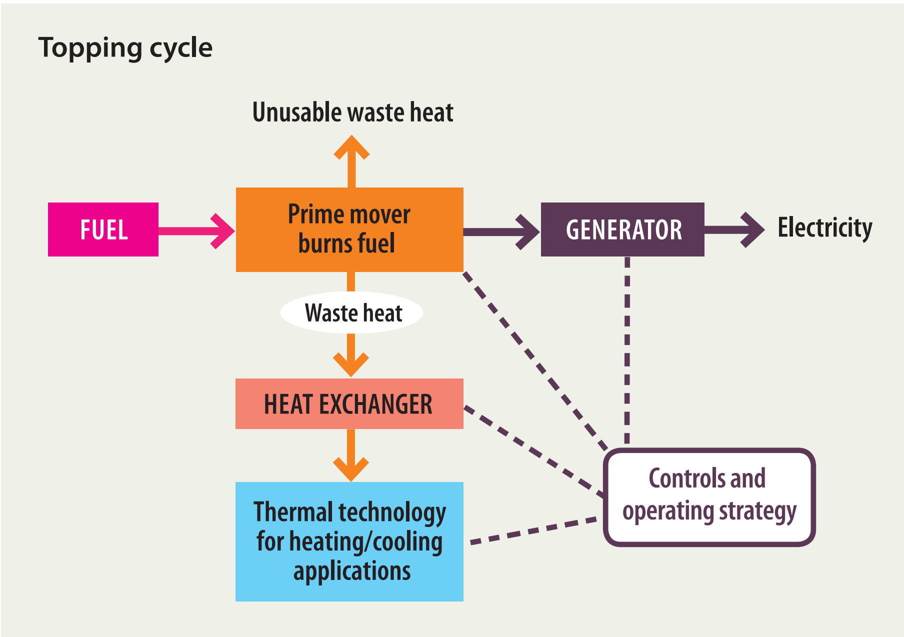


Figure 7: Process flow diagram – topping cycle

Topping cycle cogeneration systems consist of five basic components (Figure 7):

- prime mover (turbine, engine or fuel cell). The prime mover is the first stage in a cogeneration system and this equipment drives the electrical generator and produces the heat by-product
- electric generator
- heat exchanger (heat recovery system)
- absorption cooling unit (if trigeneration)
- control system (control and operating strategy).

Examples of the major components of cogeneration are outlined in Table 1 and more detail and technical specifications can be found in Appendix 2.

The prime mover is the key component of a cogeneration system, as their properties make them suitable for different circumstances. Selecting the right type and size of prime mover is pivotal to ensuring a well-designed system. This is covered in greater detail in section 4. Table 5 on page 26 provides a summary of general advantages and disadvantages of each type of prime mover technology.

Table 1: Cogeneration major components

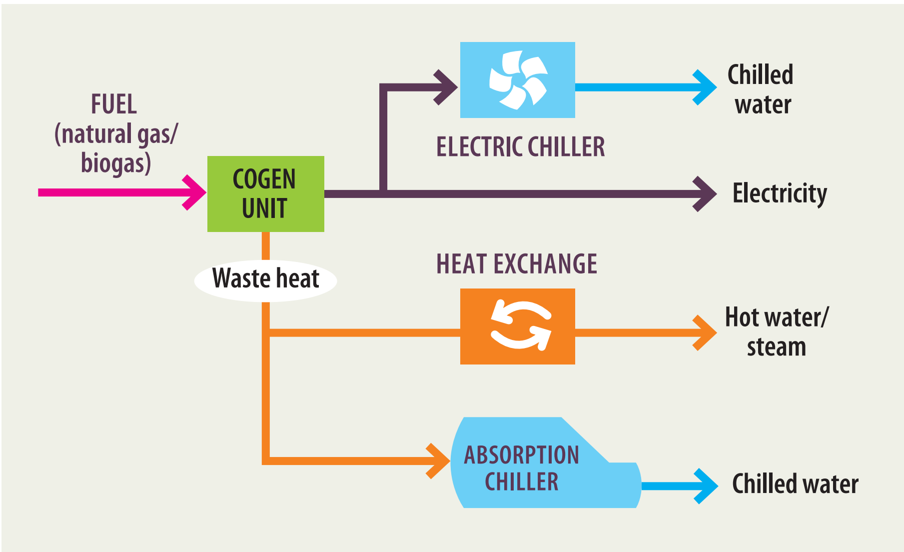
Unit	Examples
Prime mover	• Turbines (combustion, steam, and micro) • Reciprocating engines • Fuel cells
Generator	• Synchronous • Inverters • Induction
Thermal technology	• Heat exchangers • Waste heat recovery boilers • Absorption chillers • Desiccants

Cogeneration systems can be relatively complex and capital intensive and should have a plant life of 20 years. Due to their lifespan they require careful consideration when assessing viability.

3.4 Trigeneration

Trigeneration is an extension to cogeneration which involves the simultaneous production of electricity, heating and cooling. Trigeneration systems include an absorption chiller (or other thermally-powered refrigeration device) that converts the waste heat into chilled water for cooling. A schematic presentation of the principal elements of a trigeneration system is shown in Figure 8.

Figure 8: Trigeneration system



Introducing an absorption chiller into a cogeneration system enables increased use of waste heat from the system, particularly in the warmer summer periods when it can be used for air conditioning.

The efficiency of the conventional generation system where power and cooling are generated separately is compared to a trigeneration system using a gas-fired reciprocating engine with heat recovery and an absorption chiller in Figure 9. The overall efficiency of the traditional system is typically 59 per cent, compared with 66 per cent overall efficiency for the combined production of cooling and power using trigeneration in cooling mode (all of the captured waste heat is sent through the absorption chiller).

If the trigeneration plant were to operate 50 per cent of the year in heating mode (captured waste heat used in heating applications) and 50 per cent of the year in cooling mode, then the average efficiency would be 71 per cent, assuming that all recovered heat is fully utilised. In situations where the shoulder transitional periods of autumn and spring require less heating or cooling, the correct size of the plant is critical and achieving maximum efficiency may be difficult.

Note that if only 50 per cent of the total waste heat were to be used in the example below (0.4 MWr) then efficiency is reduced to 51 per cent (1.4/2.75). This is 8 per cent below a traditional system, highlighting the importance of thermal utilisation to achieving efficiency gains. For more detailed information, refer to Appendix 2 – Technology and equipment overview.

Trigeneration involves the introduction of thermally-driven cooling, such as an absorption chiller, into a cogeneration system to use the waste heat for cooling purposes. It requires additional capital expenditure, and system integration can be more complex, so greater care is required when assessing viability.

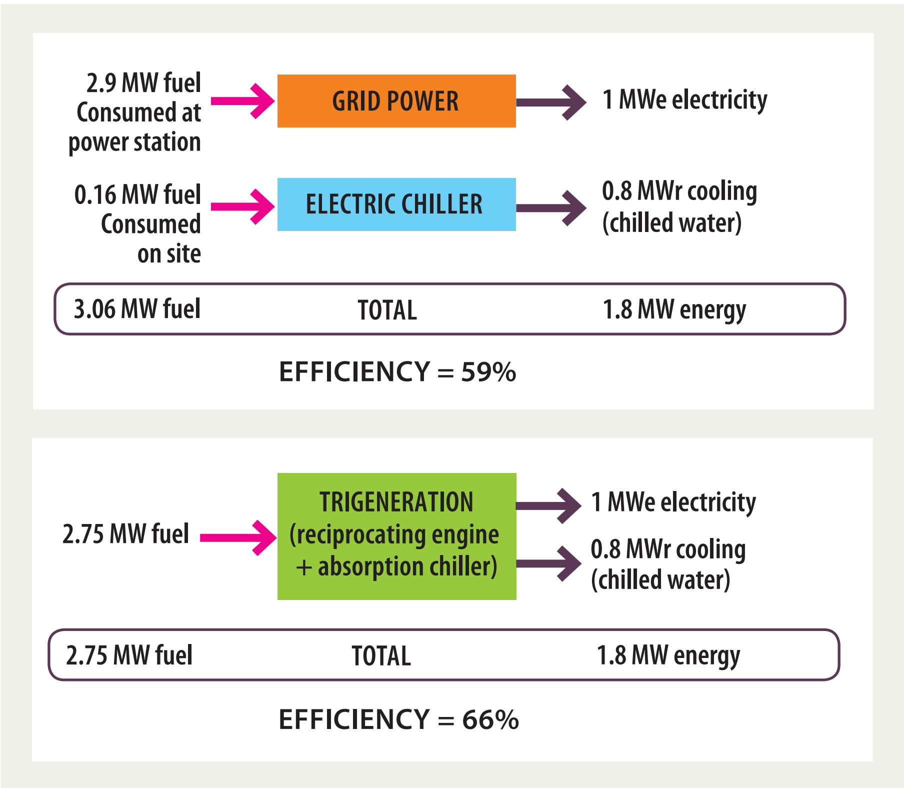


Figure 9: Conventional cooling and power compared to a 1 MW reciprocating engine trigeneration system

Assumptions: grid efficiency of 36% (HHV) generated (less 5% transmission loss); electric chiller coefficient of performance (COP) of 5.0; trigeneration reciprocating engine electrical efficiency of 36.4% (HHV); absorption chiller COP of 0.73; and all heat recovered from reciprocating engine cooling and exhaust is fully utilised to produce chilled water.

This guide provides information to help evaluate on-site cogeneration systems and does not evaluate the potential for off-site or district heating or cooling networks.

3.5 Off-site or district systems

District systems differ from on-site systems in that the heating or cooling is distributed off site to nearby consumers. District heating systems are popular in Europe where they can cover a whole district or city. Heat is generated at decentralised facilities and hot water or steam is distributed through insulated piping systems. Off-site systems are similar to district systems but may only service a small number of buildings. District systems can have larger efficiency gains as they can balance many different types of loads. Their capital cost is high, and there are also issues involved with infrastructure ownership and securing long-term commitments from consumers to purchase energy.

3.6 Business case considerations

The issues that can make or break a business case for cogeneration are summarised below.

Site specific characteristics

A site that is suitable for cogeneration should have a simultaneous and constant need for electric power and thermal energy (above 150 kilowatts (kW)) over long operating hours with a large difference in the price paid for electricity compared to gas. See section 3.7: Key factors affecting financial viability.

Appropriate sizing and selection of equipment is the most critical factor to the success of any cogeneration project.

Sizing and selection of plant

Appropriate sizing and selection of equipment is the most critical factor to the success of any cogeneration project. If incorrect, the plant will not meet the expected output or return. This is covered in detail in section 4: Sizing and selecting the cogeneration system.

Electrical and gas connection

Getting the cogeneration system connected can be a costly and timely exercise, and will require a negotiated agreement with your local district network service provider (DNSP). Understanding the site's electrical characteristics and opening clear communication lines with your DNSP early in the process is critical. Make sure that all of the electrical loads covered in the assessment are able to be connected to the cogeneration system – this may not be possible depending on the site's electrical switchboard set up. See section 5 for more details.

It is critical to ensure that the existing mains gas supply is adequate to supply the increased gas demand for running the cogeneration plant. The cost of augmentation work is prohibitive for most cogeneration projects. See section 6 for more details.

Structural and location requirements

Identifying an appropriate and available location to place the equipment early is crucial as this can significantly impact on the implementation costs if no adequate space is freely available. See section 9 for more details.

Operation and maintenance requirements

Integrating a new plant with the existing plant can sometimes be a challenge. Implementing a cogeneration system will increase maintenance requirements and require site operators to be up-skilled. There may be a limited number of people with operational knowledge of, and skills with, cogeneration or trigeneration systems. However, there are a number of different ways to manage this risk, which could include supplier maintenance contracts and other options related to financing models. See section 10 for more detail.

It is also important to consider the potential site disruption, including possible site downtime during implementation.

Finance

Due to the capital intensive nature of cogeneration projects, organisations may not have access to the level of capital needed. However, there are different methods for financing projects, some of which do not require any upfront capital investment. See section 11 for more details.

3.7 Financial viability

The key factors for a financially attractive cogeneration project are:

Simultaneous need for electric power and thermal energy

A site should have an electrical and thermal load over 150 kW before assessing cogeneration as an option. Cogeneration plants are generally not available under this size or the capital expenditure is greater than the potential returns over the plant's lifetime.

In addition, cogeneration projects only become financially attractive when the power and heat loads are similar in level at similar times over the year. Seasonality of heat load is common at many sites and must be understood to establish likely thermal utilisation.

It may be possible to store thermal energy until needed, using thermal storage. This usually requires additional equipment, such as large insulated water tanks. However, if thermal storage is required then the project is likely to be less viable due to increased capital costs of additional equipment. This can be determined during a full engineering assessment.

Guideline:

If more than 60 per cent of the available thermal energy from the prime mover can be used on an annual basis, cogeneration may be financially attractive.

Constant loads

The demand for heat and electricity must be reasonably constant, so that the cogeneration system can operate at close to full load most of the time. The cogeneration plant must have a high usage from being heavily loaded and running as many hours as possible throughout the year.

Spark spread

'Spark spread' is the difference between the price of purchasing electric power from the grid (including network charges) and the cost of natural gas. Projects are more financially attractive when the spark spread is larger. This is especially true when waste-to-energy projects are a possibility, as the biogas source can potentially be very cheap, if not free.

Smaller systems require larger spreads. Calculating the spark spread will usually require the gas units be converted from gigajoules (GJ) to kilowatt hours (kWh). This can be done using the following equation: 1 GJ ≈ 278 kWh.

Spark spread ($/kWh) = average annual electricity cost ($/kWh) – average annual gas cost ($/kWh).

As cogeneration systems have a life of over 20 years, future expectations of price should be taken into consideration. See section 7 for more information.

Guideline:

If 'spark spread' is greater than $0.04/kWh, then cogeneration may be financially viable.

Long operating hours

Payback periods are improved when the operating hours of plant are longer.

Cogeneration systems should operate when the cost of generating electricity is lower than the cost of electricity supplied from the grid. This is usually at peak and shoulder electricity rate periods (12 hours to 15 hours per day).

Guideline:

Cogeneration operation for fewer than 3300 hours per year may make it difficult for a plant to be sized efficiently and generate the level of return needed to make it viable. The average commercial office building operates for approximately 3080 hours per year (based on 6 am–8 pm, 220 days a year).

Due to the lower price of off-peak electricity, running cogeneration during off-peak periods may be more expensive than purchasing electricity from the grid.

Thermal utilisation at all times of plant operation is critical to ensuring adequate returns.

Plant running times of fewer than 3300 hours per year will normally not generate enough energy savings to justify investment unless other project drivers exist (such as backup power requirements). An average office building operates about 3080 hours per year (14 hours a day, 220 days a year), making an attractive cogeneration business case difficult for most office buildings.

Sites where there is continual use of thermal energy (24 hours, seven days a week), such as hospitals and industrial facilities, are likely to have a cogeneration unit operating for more than 6000 hours per year including at off-peak electricity rate times. In this case, the benefit of thermal waste usage is greater than the loss made by generating electricity rather than purchasing it at off-peak times and therefore running the unit continuously will be financially viable.

Fuel availability

Natural gas is currently the most commonly used fuel for cogeneration in Australia, as technologies for its use are proven and reliable. A cogeneration project is less likely to be financially viable if natural gas or a biomass derived fuel is not readily available.

Refer to section 6 – Natural Gas Network connection

Suitable location

A cogeneration facility should be located at or near the building or facility using the produced heat so that transport distance is minimised. It is also important to consider noise levels and accessibility.

Refer to section 9 – Civil and structural considerations.

If all the above criteria are satisfied, then cogeneration is more likely to be feasible.

3.8 Common design mistakes

There are five key cogeneration design problems that may cause the installed system to perform poorly or not reach financial expectations:

Not accounting for the planned impact of energy efficiency projects on the facility loads

If the cogeneration electrical output exceeds the facility load, then the plant will typically have to operate at part load, because export of power to the grid in Australia is generally not economically viable. On the other hand, if the cogeneration thermal output exceeds the need of the facility the heat has to be lost, usually to atmosphere. In either case, energy savings are not realised and the payback period of the cogeneration project becomes poorer.

Implementing traditional energy efficiency measures is often a more cost effective way of reducing costs. Conducting an energy audit; ensuring potential energy saving opportunities are implemented prior to adopting cogeneration; and incorporating any planned significant production/site usage changes into future plant energy demand calculations will help avoid the issue of poorly sizing the cogeneration system.

Inaccurate or incomplete thermal and electrical load data

This may cause the cogeneration system to be poorly sized. This will lead to low utilisation of the cogeneration plant, reducing the energy savings and negatively affecting the payback period. Adequate data logging will reduce uncertainty about facility loads when evaluating cogeneration.

Not accounting for sudden load changes in electrical or thermal demand

Sudden changes can result in frequent tripping (when the engine output cannot follow the electrical loads) of the cogeneration plant, producing increased mechanical and thermal stress on the plant. This can lead to more frequent breakdown and reduced equipment life.

The facility loads should be well understood and any events resulting in sudden load changes understood in terms of their frequency, predictability and magnitude of the load change. Avoiding this pitfall requires an individual load breakdown and analysis, which is generally completed at the full engineering assessment stage.

Overestimation of the cost savings attributed to demand charge reductions

Network service providers base demand charges on the peak or maximum demand, measured as a maximum half-hourly kW or kilovolt- ampere (kVA) power reading at the customer's connection point during a specified period, usually monthly. If the cogeneration plant is offline at any time due to maintenance or a breakdown, there may be no saving in demand charge. The evaluation of cogeneration should include an assessment of scheduled maintenance requirements and plant reliability to arrive at a realistic reduction, if any, in demand charges.

Electrical connection does not meet network service provider requirements

The electrical connection of the cogeneration plant must consider the switchboard's current ratings, fault levels and protection systems. If mistakes are made with the design of the electrical connection, a cogeneration plant may not be electrically safe to operate and/or may not be able to secure a connection agreement with the network service provider. It is important to check that it is technically possible to connect all switchboards and loads that have been included in the feasibility study. The design of the cogeneration plant's electrical connection should be reviewed by a specialist consultant prior to construction to avoid potentially expensive changes. To help reduce the time and cost it is vital you contact your electricity retailer and/or distributor as early as possible.

Exporting power

Currently, exporting power is generally not feasible in Australia as the price received for power exported to the grid is generally less than the cost to produce it. Exporting energy to the grid has specific licensing and regulatory issues that make it complex and costly. For further details refer to sections 6 and 9.

There are a number of alternatives for heating and cooling that may be more financially attractive than cogeneration. It is important to ensure that a facility operator looks widely when investigating energy efficiency improvements and meeting the facility's thermal requirements. Refer to Appendix 2 – Technology and equipment overview for more detailed information.

3.9 Heating/cooling alternatives to cogeneration

Depending on the energy profile of the facility, there are a number of common alternative energy-efficient technologies that may be more appropriate in meeting the heating and/or cooling needs of the site. Equipment that addresses heating and cooling needs is referred to as thermal plant. Alternative thermal plant includes:

- efficient heat pumps (ground source or air source)
- condensing gas boilers
- solar thermal
- highly efficient electric chillers.

The general characteristics for different types of thermal plant for heating are outlined in Table 2.

Table 2: Thermal plant comparison

	Cogeneration plant	Ground source heat pump	Air source heat pump	Condensing gas boiler	Solar thermal
Energy saving	Med	Med–high	Med	Low–med	Med
GHG savings	Med–high	Med	Med	Low	Med
Capital costs	Med–high	Med–high	Low–med	Low	Med[1]
Fuel requirement	Gas	Electricity or gas	Electricity or gas	Gas	Nil
Requires consistent base-load	Yes	No	No	No	No
Maintenance requirements	Med–high	Med	Low	Low	Low
Heat generation temperature	High	Low–med	Low–med	High	Low–med[1]

1. High generation temperatures can be achieved with mirror concentration technologies, although these typically have a high capital cost.

The optimum outcome (efficiency gain against capital costs) ranges for different types of thermal plant depend on the quantity and temperature required for heating (Figure 10).

For more information about these technologies, please refer to Appendix 2.

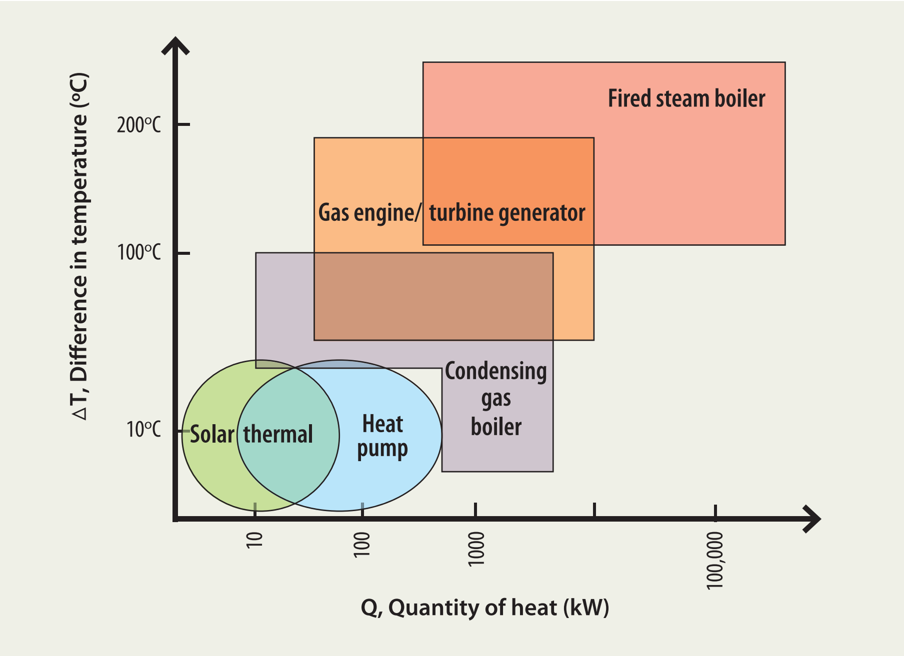


Figure 10: Temperature–quantity of heat (T–Q) diagram for alternative thermal plant

Selecting a heating system for an aquatic centre

Example

An aquatic centre requires heating for a new indoor pool. The pool water temperature is to be maintained at 33°C and the average minimum ambient temperatures range from 8°C (winter) to 19°C (summer). The maximum heating load is expected to be 75 kW in winter.

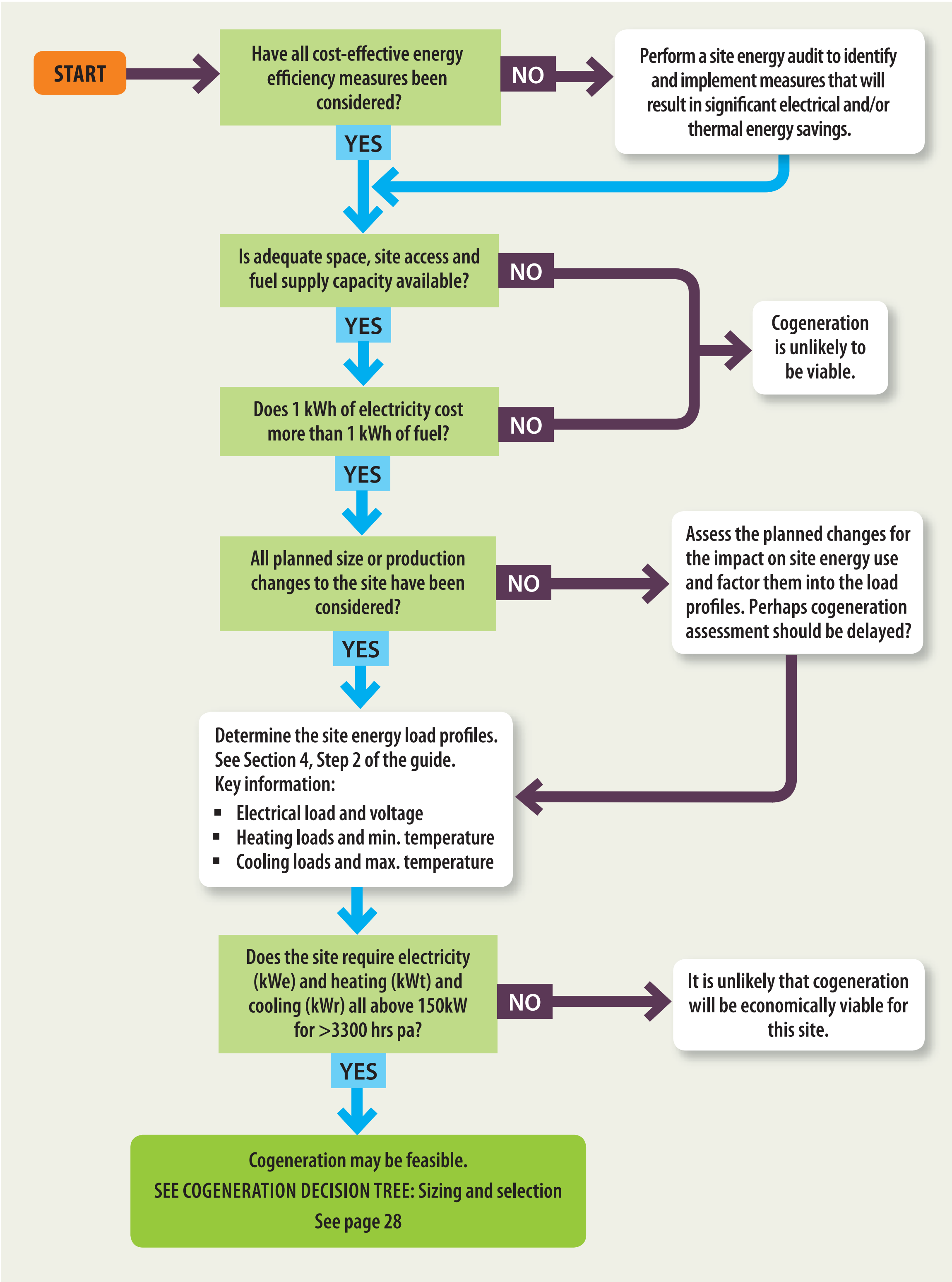
The difference in temperature (ΔT) is the pool water temperature (33°C) less the minimum ambient temperature (8 to 19°C), which is 14°C to 25°C, and the quantity of heat (Q) is 75 kW. This combination of ΔT/Q values sits in the solar thermal and heat pump regions of the T-Q diagram (Figure 10), which indicates that these technologies are probably the most suitable for this situation and should be investigated.

For information on cooling technology, including a comparison of electric chillers to absorption chillers, please refer to Appendix 2 Technology and equipment overview.

3.10 Initial viability checklist

Before beginning the detailed analysis, a preliminary screening is recommended. A preliminary screening tool that will help you to decide if cogeneration is worth further investigation is presented in Figure 11.

Figure 11: Initial viability checklist



4 Sizing and selecting a cogeneration system

Appropriate equipment sizing and selection is critical to the success of any cogeneration project. This section provides a step-by-step guide to initial sizing and selection of a cogeneration plant to help you decide if cogeneration is an appropriate way to reduce a site's energy costs, energy use and greenhouse gas emissions.

A preliminary screening is recommended before beginning a detailed analysis. This can be done by reading the general overview of the factors affecting viability found in sections 3.6 and 3.8, and using the initial viability checklist in Figure 11 on page 18. This will indicate if further investigation of cogeneration is worthwhile.

The following steps for sizing and selecting systems are described in this section:

- Step 1: Collate electrical and thermal load data
- Step 2: Analyse electricity and gas profiles
- Step 3: Select the appropriate cogeneration prime mover technology
- Step 4: Determine the required plant capacity
- Step 5: Assess the impact of tariffs on system design
- Step 6: Determine financial viability
- Step 7: Calculate the reduction in greenhouse gas emissions
- Step 8: Compare with green power.

Appropriate sizing and selection of equipment is the most critical factor to the success of any cogeneration project.

Step 1: Collate electrical and thermal load data

If the checklist from Figure 11 confirms that cogeneration may be viable at your site, the next step is to collate the electrical and thermal load data for the facility. Accurate data is vital to correctly assessing the viability of the project. At a minimum, you need interval data from your electricity supplier and daily thermal data. If the project progresses to a full engineering assessment, more detailed thermal data may be required.

Past consumption data, which can be obtained from site utility bills, usually provides a good indication of future demand, but it is also important to take site-specific factors into account, including:

- efficiency of energy use
- future changes in site energy demands
- use of heat to replace electricity
- timing of demands.

Example

An example of a soft drink bottling facility is provided to highlight sizing and selection steps. This facility will be used as an example for decision-making throughout the document.

Electrical data

Cogeneration feasibility requires an understanding of hourly, daily, weekly, monthly and yearly electrical consumption, including peak demands, which can be easily graphed once you have received the data from your electricity supplier.

Electrical data is collated from the site's electricity usage, for most facilities this data can be obtained in 30-minute (or similar) intervals from the site electricity retailer. When analysing cogeneration, this raw data should be collected for as long a period as is practical and should also relate to the site's future potential operating requirements.

For example, if you completed a major energy saving project two years ago, then earlier data would not be relevant and should not be included in the dataset.

Accurate data is vital to correctly assessing the feasibility of the project. At a minimum, you need interval data from your electricity supplier and daily thermal data.

Thermal data

Thermal load data refers to heating and/or cooling loads and can be more difficult to obtain than electrical data, because fuel or heat use is often metered in larger time increments. Site gas usage data can be used to estimate thermal loads and depending on the gas meter, interval data may be available from your gas supplier.

Heating load data (either hot water or steam) can often be extracted from a building management system (BMS) or system control and data acquisition (SCADA) system. While some cooling thermal data may also be available in the BMS or SCADA, it may require multiplying the cooling electrical load by an estimated coefficient of performance (COP) to get the resulting cooling load.

If the thermal load data is not easily available, there are two basic options for obtaining the raw interval data:

- estimating using process knowledge and engineering calculations
- data logging by installing permanent or temporary sub-metering.

For further details on data logging and calculations of thermal loads refer to Appendix 1 – Calculations and spread sheets.

An example of the thermal data required is given in Table 3 and Table 4.

Example

A bottling factory prepares soft drinks by mixing water, sugar, flavouring and carbon dioxide and filling plastic or glass containers. Heating is used for mixing and sterilisation after bottling. The mixture is cooled before bottling to make it easier to inject CO_2. Electricity is used to run the bottling and packaging machinery, lighting and other equipment. Over a year, the facility operates three, eight-hour shifts (24 hours per day) for 125 days; two, eight-hour shifts (16 hours per day) for 120 days; and does not run on weekends (120 days at zero hours per day).

Typical loads are shown in Table 3 and Table 4.

Table 3: Example of typical daily load data requirements (16 hour operating day)

Time h:min	Electrical load kWe	Heating load kWt	Cooling load kWr
0:00	335	0	0
1:00	321	0	0
2:00	324	0	0
3:00	341	0	0
4:00	289	0	0
5:00	953	500	550
6:00	1152	2015	2215
7:00	1183	2040	2244
8:00	1203	2100	2310
9:00	1189	2150	2365
10:00	1354	2110	2321
11:00	1452	2001	2200
12:00	1389	2205	2400
13:00	1350	2134	2347

Time h:min	Electrical load kWe	Heating load kWt	Cooling load kWr
14:00	1380	1995	2195
15:00	1455	1805	1980
16:00	1485	2150	2365
17:00	1555	2350	2585
18:00	1556	2250	2475
19:00	1542	2180	2398
20:00	1420	2150	2365
21:00	1621	2080	2288
22:00	1103	1200	1320
23:00	385	0	0

Table 4: Facility monthly energy demand data requirements

Month	Electrical kWe	Heating kWt	Cooling kWr
Jan	1389	2413	2654
Feb	1267	2389	2628
Mar	1156	2215	2437
Apr	1123	2326	2559
May	1159	2359	2595
Jun	1089	2103	2313
Jul	1056	2059	2265
Aug	1079	2046	2251
Sep	1489	2468	2715
Oct	1523	2579	2837
Nov	1512	2545	2800
Dec	1269	2156	2372

Example

Where electrical and/or thermal data is not easily available, data logging is required. Data logging and collection is typically undertaken as part of an energy audit. For more information on energy auditing please visit the Office of Environment and Heritage website: **www.environment.nsw.gov.au/sustainbus/energyauditing.htm**

Step 2: Analyse electricity and gas profiles

Sudden large load changes, either electrical or thermal, can result in frequent tripping. Tripping is the when sites electrical protection devices isolate the plant, effectively shutting it down. This can cause increased mechanical and thermal stress on the cogeneration plant, more frequent breakdowns and ultimately reduced equipment life. Facility loads should be well characterised and the frequency, predictability and magnitude of any load changes understood.

Next, you will need to develop yearly and operational load profiles, to:

- understand minimum and maximum thermal and electrical loads
- determine the ratios of thermal and electrical needs of the site over the year
- determine the typical site operating profile and evaluate the effect on the site's thermal and electrical needs.

Understanding your usage profile allows you to select the type and size of cogeneration technology.

Yearly profile

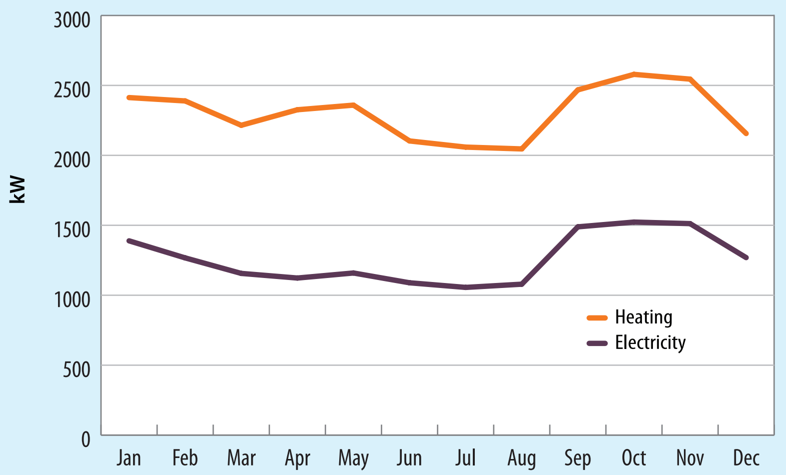
Once a relevant and appropriately sized dataset has been collected for both the electrical and thermal data, it should then be graphed into a yearly profile. The seasonality of energy use should be reviewed to help identify which operational profiles should be completed.

Example

The energy load at the soft drink facility is seasonal according to the yearly energy profile (Figure 12).

The seasonality reflects higher soft drink sales during the summer months. The underlying driver of increased energy use in this case is the longer operational hours per day needed to produce the volume of soft drink required in summer.

Figure 12: Yearly energy profile for soft drink bottling facility



Operational load profiles

The data should then be broken up into operational profiles to reflect the typical operational variations in load over time. Common operational profiles span a day, a week and a month.

An operational load profile is developed by taking the average of all the data for that particular time period.

Some sites, such as commercial office buildings, may have fairly predictable load profiles and be dependent on just a few variables, such as weather or occupancy. Other facilities may be more complex.

Two other examples of varying operational profiles are:

- A brewery has major production peaks and larger refrigeration loads in the warmer months. In this case, load profiles should be developed for both the peak operating season and the quiet period (winter) for an average day, week and month.
- An aquatic centre has an open air pool and air conditioning for its offices and change rooms. This application requires heating and cooling. These loads will vary significantly throughout the year as the seasons change. In this case, load profiles for typical winter and summer days should be developed. If the facility is closed for significant parts of the year then this period should also be analysed.

Example

Over a year the bottling facility operates for the full 24 hours for 125 days; for two, eight-hour shifts (16 hours per day) on 120 days; and does not run on weekends, another 120 days. Operational load profiles for each operation type are shown in Figures 13–15.

Figure 13: Soft drink bottling facility operating 24 hours per day

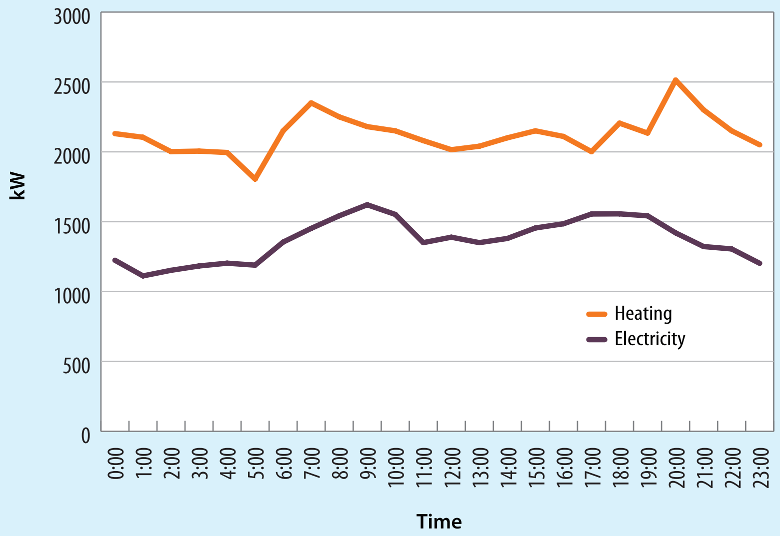
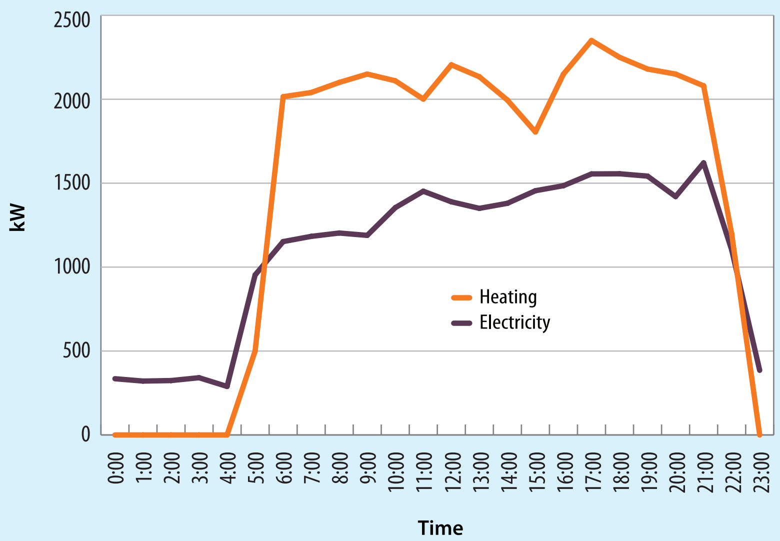
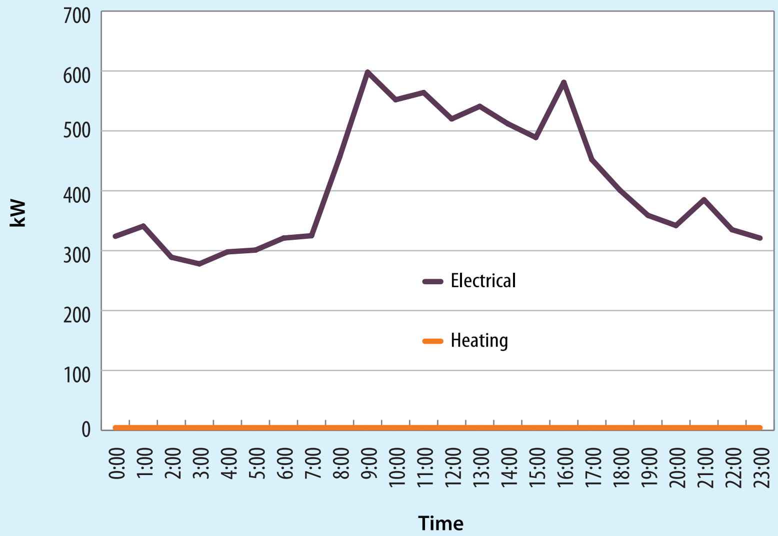


Figure 14: Soft drink facility typical load profile when operating 16 hours per day



Example

Figure 15: Soft drink bottling facility when non-operational



As these typical daily load profiles show, the facility has electrical loads even when it is not operating, due to non-operational loads such as perimeter lighting and backup systems.

The profiles (Figures 13–15) can be summarised as follows:

- maximum electrical load: ~ 1500 kWe (see highest point in Figure 13)
- base electrical load: ~ 300 kWe (lowest point in Figure 14)
- maximum thermal load: ~ 2500 kW (highest point in Figure 14)
- base thermal load: ~ 0 kW (lowest point Figure 15).

This example answers the question in the checklist (see Figure 11) – does my plant use electricity (kWe) and heating (kWt) or cooling (kWr) at levels above 150 kW for over 3300 hours per year? The site's electrical consumption never drops below 300 kWe and although the site's thermal load (kWt) drops to zero at some points during non-operational periods, it exceeds 150 kWt for most of the year (Figure 13).

Step 3: Select the appropriate cogeneration prime mover technology

Cogeneration design and selection is an iterative process and it is sometimes better to select equipment before sizing, as in our bottling factory example. However, in some cases, it may make more sense to size first.

The prime mover is the heart of the cogeneration system and correct selection is vital for a successful system. The main factors governing selection are:

- fuel(s) available, or in the case of a waste heat recovery system, the temperature of waste heat available
- grade (temperature) of heat required on site
- heat to power ratio (the ratio of recoverable heat to electrical output)
- amount of electrical output required
- form of thermal load (hot water, steam, chilled water) and conditions (temperature and pressure).

There are secondary considerations that may also impact selection:

- available space
- air emissions
- noise
- engine turn down (ability to vary thermal and electrical output)
- maintenance and reliability.

There are a variety of prime movers available. The most common categories are:

- reciprocating engines
- gas turbines
- steam turbines.

Table 5 summarises prime mover characteristics and provides a basis for initial selection. All of these characteristics must be considered in selection. For example, if backup power is very important, such as in a data centre, one might choose a small gas turbine rather than a reciprocating engine. Even though the engine has a higher electrical output and is cheaper, the gas turbine is more reliable leading to fewer outages.

Table 5: Prime mover technology options

Cogeneration system	Advantages	Disadvantages	Available sizes
Spark ignition reciprocating engine (1500 rpm)	• High electrical efficiency • Good part load efficiency • High grade heat (exhaust) • Fast start-up • Low pressure gas fuel	• High relative maintenance costs ($/MWh) • Low grade heat from engine cooling • Relatively high emissions • Engine must be cooled if heat not used	50–4,000 kW
Gas turbine	• High reliability • Low emissions • High grade heat (exhaust) • Minimal cooling required	• Medium pressure gas fuel • Poor part load efficiency • Output falls as ambient temperature increases • Performance degrades over time	1000 to >30,000 kW
Microturbine	• High reliability – small number of moving parts • Compact size and weight • Low emissions • No cooling required • Fast start-up	• High pressure gas fuel • High relative capital cost ($/kW) • Low electrical efficiency • Low grade heat (exhaust) • Performance degrades over time	30–250 kW
Fuel cell	• No direct emissions • Low noise • High electrical efficiency over load range • Modular design • Low pressure gas fuel • No Nox Emissions	• Very high relative capital cost ($/kW) • Low durability • Very low power density • Gas fuel requires processing • Low grade heat • Fuel cell must be cooled if heat not used • Performance degrades over time	5–1400 kW
Steam turbine	• High thermal efficiencies possible • Highly reliable • Compact • Versatile in configuration • Runs on heat as opposed to fuel	• High cost at smaller sizes • High grade heat required • Low electrical conversion	80 to >500,000 kW
Organic Rankine cycle	• Low grade heat acceptable • Highly reliable • Runs on heat as opposed to fuel	• Low electrical conversion • High relative capital cost • Higher electrical efficiencies at lower in out temperatures	30 to 10,000kW

Using the decision trees for technology selection

The decision trees on the following pages should be used to select the type of prime mover technology:

- cogeneration decision tree – heating and electricity (kWe and kWt) needs are both greater than 150 kW (Figure 16)
- trigeneration decision tree – cooling and electricity (kWe and kWr) needs are both greater than 150 kW (Figure 17).

Always start with the cogeneration decision tree as these systems maximise the use of heating and electricity and are normally more viable than trigeneration. The trigeneration decision tree examines whether the addition of thermally-driven cooling plant is viable and if so, helps you to determine a suitable chiller type.

Once the list of appropriate technologies has been identified, the capacity or 'sizing' of the prime mover can be determined. The best size and configuration should be based on the outputs of financial, energy saving and GHG reduction calculations.

Example

The soft drink bottling facility satisfies all of the conditions in the viability checklist and can now move on to the technology selection decision trees.

Starting at the cogeneration decision tree (Figure 16), the first question asks whether heat is needed above or below 100°C. The bottling facility only requires low grade heat or hot water – most of its heating load is only required at 50°C, to heat the beverage to enable labelling.

This answer directs you to the right-hand side of the decision point. As the electrical peak requirement for the facility is 1600 kWe, the heating and electrical load profiles at this step indicate that microturbine or reciprocating engine technologies are appropriate.

The next step is to decide between these two prime movers. The facility selected a reciprocating engine after weighing up the options (Table 5):

- reciprocating engines have a higher electrical efficiency than microturbines, and will deliver cost savings and GHG reduction
- the largest size microturbine available typically has about 250 kWe output, so as many as five units would be required at the factory. Conversely, 600 and 1250 kWe output reciprocating engines are common and competitively priced
- the reciprocating engine has a better capital to kWe output ratio
- the heat required on site is similar to the electricity requirements so a heat to power ratio of the reciprocating engine (approximately 1:1 compared to 2:1 of microturbine) means that there is a lower likelihood of the thermal energy being wasted.

Now that a reciprocating engine has been selected as the prime mover, the tree guides you to determine plant capacity, otherwise referred to as plant sizing.

Although there may be a cooling load, a cogeneration system is more financially attractive (for operational and capital project optimisation) if the heating thermal load is considered first. This is because cooling involves the purchase of more assets which adds cost and complexity to the project. In most cases, it is more economical to use the heat directly rather than converting to cooling. The additional expense of waste heat-driven cooling equipment (e.g. an absorption chiller) needs to be justified by the increase in electrical generation and offset by the amount of electricity no longer needed by electric chillers.

Figure 16: Scenario 1: heating and electricity both greater than 150 kW

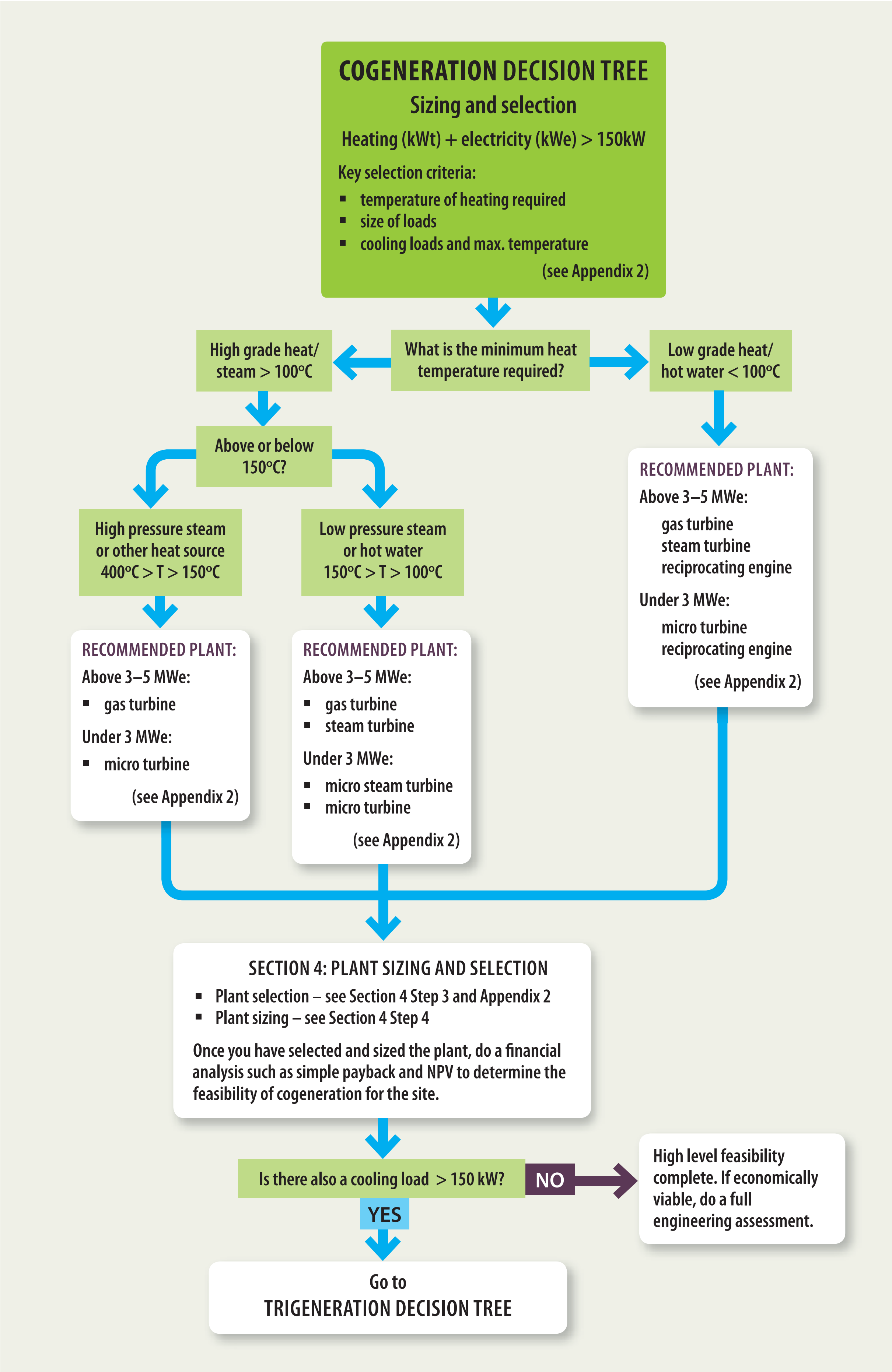
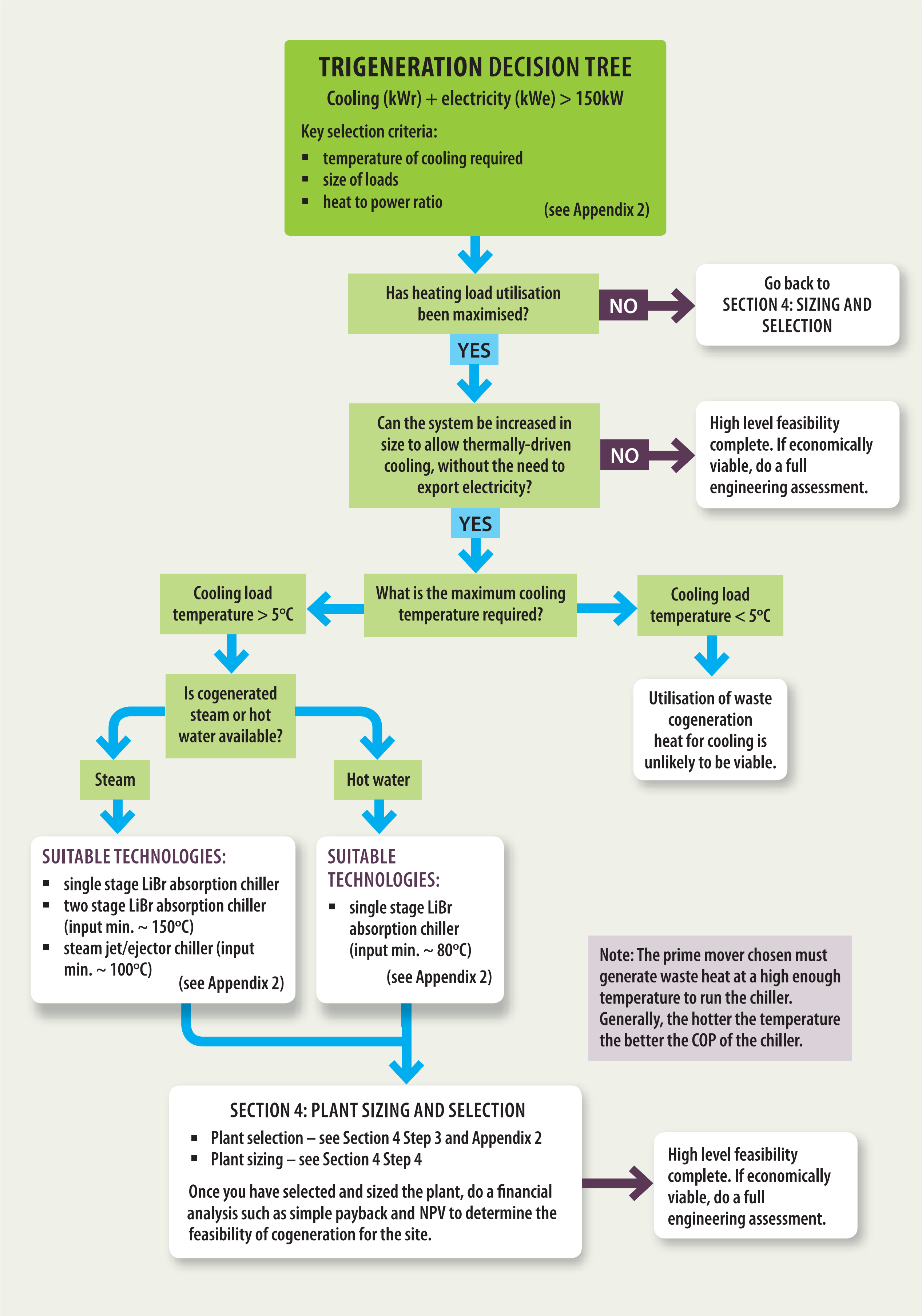


Figure 17: Scenario 3: cooling and electricity both greater than 150 kW (topping cycle 3)



Step 4: Determine the required plant capacity

Common mistakes made with cogeneration plants are oversizing or selecting technology that doesn't suit the facility. This results in poor plant reliability, low efficiency and failure to deliver on project costs and energy reduction targets. These issues generally arise from the plant output not matching the energy requirements of the facility and resulting in poor or low utilisation.

What drives plant size?

The drivers behind cogeneration and site energy load profiles are important when determining the optimum size of a cogeneration plant. Common reasons for installing cogeneration include:

- reducing site energy costs
- reducing site energy consumption and/or improving energy efficiency
- reducing the site's GHG footprint.

The chosen size of a cogeneration system may differ according to which of these is the primary driver. A number of potential plant sizes might need to be passed through financial, energy and GHG reduction analysis to determine the right size.

For example, a plant which runs as many hours as possible per year will deliver greater energy and GHG reductions. However, if the off-peak electricity price is lower than the cost of the combined fuel input and operation/maintenance costs, then the plant will cost money in off-peak hours.

It is important to maximise the thermal and electrical utilisation when sizing a cogeneration plant. A cogeneration plant should be operating at, or close to, full output/load as much as possible.

General sizing considerations:

Smaller is better

- plant should be as small as possible while maximising the amount of electricity generated on site. Due to the relatively high value of electricity, it is the electricity generated by the plant that generates the greatest operational cost savings
- plant should not be sized above peak electrical demand with a view to export. Exporting electricity is currently not generally financially viable
- plant should be sized to match the lowest base load, whether that is thermal base load or electrical base load
- it is common practice to include a 'network safety margin'. This margin reduces the size of the plant to help mitigate the risk of overproducing electricity if a major piece of equipment stops and on-site demand reduced quickly. For example, if the optimum theoretical size was 450 kW, a safety margin of 50 kW might be applied and therefore a 400 kW unit would be specified. The magnitude of the margin depends on the type and size of electrical equipment on site.

As a general rule, plant should be sized to match the lowest base load whether that is thermal base load or electrical base load.

Maximise heat recovery

- plant should be sized to maximise the heat recovered. Thermal heat recovered and used in processes further reduces operational costs
- any thermal energy available from the cogeneration plant that is not used by the facility is reducing the potential operating cost savings of the cogeneration plant

Understanding impact of load variations

- a single prime mover plant can vary output down to about 50 per cent of its stated size, after which it must be shut down. For most plants, efficiency reduces as the load decreases from the maximum. See Appendix 2: Technology and equipment overview for further details
- when analysing electrical data, allow for a reduction in electric chiller loads if an absorption chiller is introduced
- due to differing electrical layouts it is not often possible to pick up the entire electrical load at the switchboards. A full breakdown and analysis is usually carried out in the full engineering assessment stage

Different sizing approaches

Some approaches to sizing are outlined below. Note that sizing is very site specific and each method may be viable depending on the site operating profile. Thought should be given to the general considerations mentioned above.

Sizing to base load thermal demand – this will generally ensure that the majority of waste heat is used and maximise the efficiency of the system. This method is generally more suitable if your electricity load is greater than your heat load.

Sizing to base load electrical demand – this maximises the run times and ensures the plant will operate close to 100 per cent. This method is recommended when your thermal load is greater than your electrical load. Note that the financial return is usually gained through electricity generation. This is a common method for sizing, but it may not lead to the most efficient system.

Sizing to electrical peak load – may limit plant operating run times. It may lead to excessive thermal wastage and reduce efficiency gains, and is not recommended for most circumstances.

Sizing to thermal peak load – may limit plant operating run times and is not recommended for most circumstances.

Sizing for trigeneration

When sizing a trigeneration unit, you should also consider periods of low loading. Turndown limitations that should be considered are:

- electrical power generation at less than 50 per cent of the generator's rated capacity is typically not possible. At lower electrical loadings the generator would normally be stopped and then restarted when the electrical loading has risen above the minimum level for a sustained period. While the generator is stopped, all power is imported from the external electricity grid
- absorption chillers can typically operate at reduced capacity, down to 10–30 per cent of their rated output.

The waste heat generated should be used for heating as a priority before sending it to an absorption chiller to provide cooling. If, for example, 100 per cent of the sites hot water requirements have been met by only 50 per cent of the waste heat generated by the trigeneration unit, the other 50 per cent of the waste heat could then be used in the absorption chiller to provide space cooling.

> For the cogeneration plant sizes covered by this guide (< 5 MWe) it is usually not viable to export power to the grid, as the fuel plus operation and maintenance cost of cogeneration normally exceeds the revenue generated by sale of electricity to the grid (refer to section 6 for more details on exporting).

Example

Example

Following the selection of a reciprocating engine as the prime mover, the following assumptions are made:

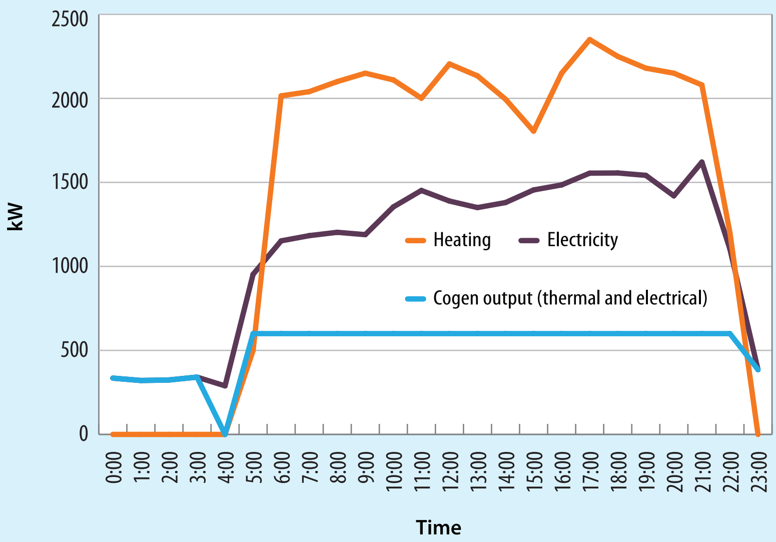
- there are two electricity tariffs throughout the day: peak/shoulder (6 am to 10 pm) = $0.10/kWh and off-peak (10 pm to 6 am) = $0.05/kWh
- gas cost is $6.00/GJ (= $0.0216/kWh)
- engine operation and maintenance costs are approximately $0.02/kWh
- the engine produces an energy split of 40% electricity, 40% hot water (heat to power ratio of 1:1) and 20% heat losses (unusable heat)
- the engine can vary its output down to 50% after which is must be shut down
- the facility is predicted to have 120 non-operational days per year, 120 x 16 hour operational days per year and 125 x 24 hour operational days per year.

Upon review of the load profiles, three engine sizes are possible:

1. 600 kWe engine, sized to maximise its electrical generation and therefore have the longest potential run time. Its load curve is shown in Figure 18

Pro	When the facility is not operational the engine can turn down 50 per cent to a base load of approximately 300 kWe. The engine would therefore only stop occasionally when the site electrical load drops below 300 kWe
Con	The drawback is that there is no heat demand when the engine is running during non-operational periods. This means that the heat generated by the engine during these times is wasted

Figure 18: 600 kWe engine load profile



2. 2000 kWe engine sized to maximise the thermal utilisation of the plant. Its load curve is shown in Figure 19

Pro In this case, we see that the site's thermal load sits at around 2000 kWt while it is operating. We therefore select a 2000 kWe engine with a thermal output of approximately 2000 kWt

Con At this size, the 2000 kWe of electrical energy produced exceeds the site's electricity requirements and would either need to shut down or, if feeding electricity back into the grid is technically possible and financially viable, export power. In NSW at present, the tariff (price) received for selling electricity back into to the grid generally makes this financially uneconomic and therefore this is not the preferred sizing

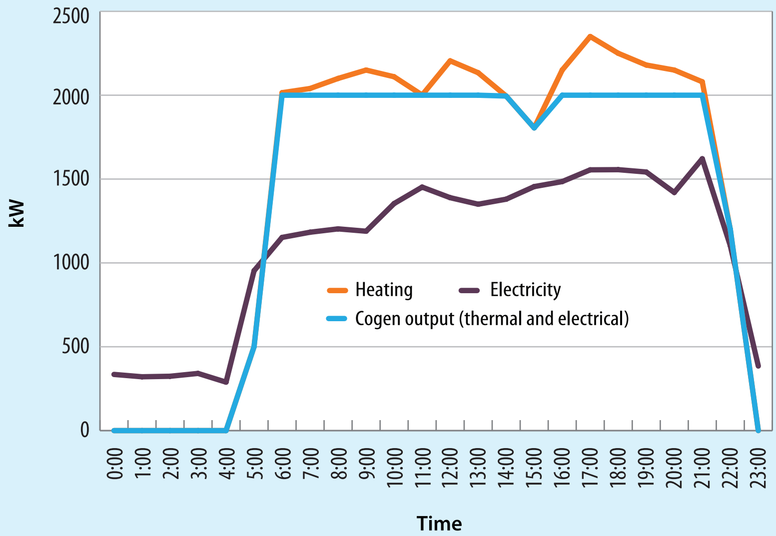


Figure 19:
2000 kWe engine

3. 1250 kWe engine sized to maximise the electrical and thermal utilisation during operational periods. Its load curve is shown in Figure 20

Pro The engine is sized to run at maximum electrical and thermal utilisation just during operational periods for the site, when the energy loads are significantly higher. At 1250 kWe (and therefore 1250 kW thermal), the engine will stay fully loaded almost all of the time during the operational periods.

Con The engine would therefore shut down during non-operational periods, reducing its overall utilisation.

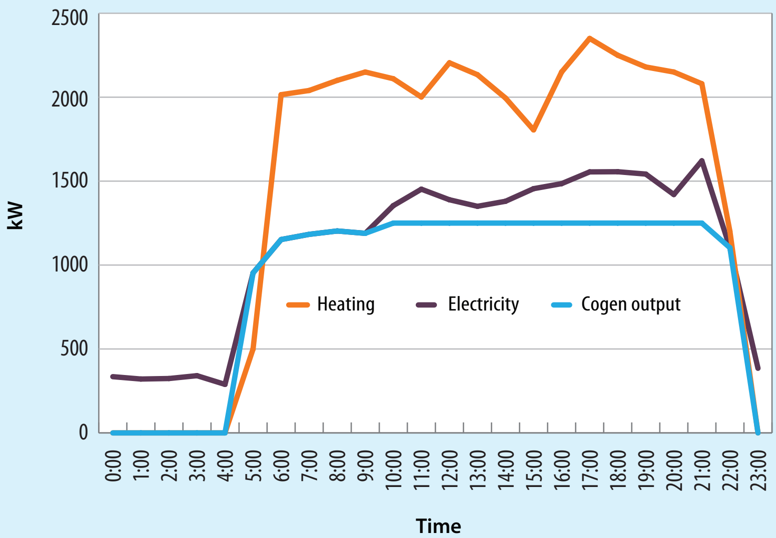


Figure 20:
1250 kWe engine

Example

Example

The 2000kWe unit can be discounted as exporting electricity is generally unviable. The choice between the first and third options would then be made on a financial and/or energy and GHG reduction analysis (depending on the project's drivers).

Having chosen a prime mover (reciprocating engine) and suggested two possible sizes (600 kWe and 1250 kWe), we can now determine if trigeneration is worth considering. Using the trigeneration decision tree (Figure 17) the following questions are answered.

Q: Is there also a cooling load?'

A: Yes, used in refrigeration and blast chilling process.

Q: Is all the heat utilised?

A: Yes all the heat is utilised as the thermal output is below the site's thermal needs.

Q: Can the size of the unit be increased?

A: Yes, for the 600 kWe unit but perhaps not for the 1250 kWe (in both cases the electrical output could be increased, but more so with the 600 kWe size).

Q: What is the maximum temperature at which cooling is required?

A: Cooling is required below 4°C. This then suggests that trigeneration is probably not viable.

As trigeneration is not a viable option, we now compute the cost, energy and GHG savings of the two reciprocating engine cogeneration options (600 kWe or 1250 kWe) to assess project viability.

Total electrical generation and fuel quantity calculation

The next step is to calculate the total electrical generation and fuel input requirements for each potential plant size as this will allow you establish the costs and benefits of running the different-sized systems. This is done using the typical load profiles and the corresponding engine outputs.

Take the following steps for each potential size:

- determine the load factor by establishing the heat and electrical output of engine compared to load profile of site. This allows you to calculate the electrical outputs and gas inputs
- calculate the electrical outputs using the following equation:

  engine electrical rating x load factor x operational days per annum x 24 hours per day = total annual kWh of electricity generated
- calculate the natural gas requirements to run the plant using the following equation:

  ((engine electrical rating) / (engine electrical efficiency %) x 100%) x load factor x operational days per annum x 24 hours per day = total annual kWh of gas required for that specific operational load profile.

The 16 hours per day load profiles for the soft drink bottling facility are shown in (Table 6).

Table 6: Load factor calculation for 600 kWe and 1250 kWe for bottling facility running 16 hours per day

Daily data 16 hours			600 kWe engine output			1250 kWe engine output		
Time	Heat kW	Elec. kW	Heat kW	Elec. kW	Load %	Heat kW	Elec. kW	Load %
12:00	2205	1389	600	600	100	1250	1250	100
13:00	2134	1350	600	600	100	1250	1250	100
14:00	1995	1380	600	600	100	1250	1250	100
15:00	1805	1455	600	600	100	1250	1250	100
16:00	2150	1485	600	600	100	1250	1250	100
17:00	2350	1555	600	600	100	1250	1250	100
18:00	2250	1556	600	600	100	1250	1250	100
19:00	2180	1542	600	600	100	1250	1250	100
20:00	2150	1420	600	600	100	1250	1250	100
21:00	2080	1621	600	600	100	1250	1250	100
22:00	1200	1103	600	600	100	1103	1103	88
23:00	0	385	385	385	64	0	0	0
0:00	0	335	335	335	56	0	0	0
1:00	0	321	321	321	54	0	0	0
2:00	0	324	324	324	54	0	0	0
3:00	0	341	341	341	57	0	0	0
4:00	0	289	0	0	0	0	0	0
5:00	500	953	600	600	100	953	953	76
6:00	2015	1152	600	600	100	1152	1152	92
7:00	2040	1183	600	600	100	1183	1183	95
8:00	2100	1203	600	600	100	1203	1203	96
9:00	2150	1189	600	600	100	1189	1189	95
10:00	2110	1354	600	600	100	1250	1250	100
11:00	2001	1452	600	600	100	1250	1250	100
Average					**87**			**73**

Note: for an actual thermal breakdown of a reciprocating engine please refer to Table 21 in Appendix 2.

The 600 kWe engine has an 87 per cent load factor and the 1250 kWe engine has a 73 per cent load factor for 16 hours a day operation. The load factors for the other typical load profiles, calculated in the same way, are as follows:

- 24 hour operational day, 600 kWe ~ 100%
- 24 hour operational day, 1250 kWe ~ 98%
- non-operational day, 600 kWe ~ 63%
- non-operational day, 1250 kWe ~ 0%.

Example

Example

In this case, the engine sizing tends to follow the electrical needs of the site and therefore determine the load factor. The next step is to calculate the natural gas requirements and the electrical outputs for the two engine sizes. These results are shown in Table 7.

Table 7: Gas requirements and electricity output for 600 kWe and 1250 kWe engine for soft drink bottling facility

					Gas input		Electricity output
Operation (hours)	Engine kWe	Electrical generation efficiency[1] %	Load factor %	Annual days	kWh	GJ	kWh p.a.
24	600	40	100	125	4,500,000	16,200	1,800,000
16		40	87	120	3,758,400	13,530	1,503,360
0		40	63	120	2,721,600	9,798	1,088,640
				Total	**10,980,000**	**39,528**	**4,392,000**
24	1250	40	98	125	9,187,500	33,075	3,675,000
16		40	73	120	6,570,000	23,652	2,628,000
0		40	0	120	0	0	0
				Total	**15,757,500**	**56,727**	**6,303,000**

Notes: 1. Electrical generation efficiency is based on electrical generation output divided by fuel consumption.

In summary, the total electricity produced per year is:

- 600 kWe engine – 4,392,000 kWh
- 1250 kWe engine – 6,303,000 kWh.

The gas usage in each case is:

- 600 kWe engine – 39,528 GJ
- 1250 kWe engine – 56,727 GJ.

In the next steps, these figures are used to assess the costs and benefits of generating electricity and using the waste heat.

Step 5: Assess the impact of tariffs on system design

The cost savings from cogeneration are largely derived from the difference between the cost of purchasing electricity (including all network and environmental charges) to that of purchasing alternative fuel, such as natural gas, to generate your own electricity. This is often referred to as the spark spread. Currently the retail price of natural gas is generally less than grid generated electricity.

Grid electricity compared to natural gas prices

The best case for a cogeneration operator is high electricity prices and low fuel prices. In some cases, by significantly increasing the amount of gas required on site, you may be able to negotiate a reduced gas price and further enhance spark spread.

A positive spark spread means it is economically beneficial to operate the cogeneration unit. A negative spark spread means it is better to buy directly from the grid.

When evaluating the feasibility of a cogeneration system, it is important to look not only at the current heat and electricity tariffs but also to make appropriate forecasts. It is recommended this be done using expert guidance (for more information refer to section 7). Another important consideration is peak demand charges and the ability for a cogeneration plant to reduce them. Peak demand charges are levied against a site based on the highest metered electrical current during a peak period. This is normally set as the highest demand reached over a month but if they are based on the maximum peak period demand for the previous 12 months, no peak demand charge savings may be realised. Contact your district network service provided (DNSP) to clarify how your demand charges are set and what reductions in peak demand charges are possible.

The cost savings from cogeneration are largely derived from the difference between the cost of purchasing electricity (including all network and environmental charges) to that of purchasing alternative fuel such as natural gas to generate your own electricity.

Peak demand charges are levied against a site based on the highest metered electrical current during a peak period. This is normally set as the highest demand reached over a month but if they are based on the maximum peak period demand for the previous 12 months, no peak demand charge savings may be realised.

Example

Tariff impact on soft drink facility – peak demand savings estimate

Key assumptions:

- peak demand charge (sometimes referred to as capacity charge) of $14/kVA/month
- the facility's existing average peak electrical demand is 2123 kVA (average maximum monthly peak)
- typical uptime of gas engine is 85per cent
- the engine will reduce the peak demand for eight months out of 12; this conservative estimate accounts for unscheduled maintenance.

This demand savings calculation considers that the peak demand for grid-supplied electricity will be reduced by 600 kVA or 1250 kVA for eight months each year and that the electricity tariff demand charge is based on the highest peak period electrical demand each month.

For the 600 kWe engine, peak demand charge savings are

600 kVA x $14/kVA/month x 8 months/year = $67,200/year.

For the 1250 kWe engine, peak demand charge savings are

1250 kVA x $14/kVA/month x 8 months/year = $140,000/year.

The above assumptions made for peak demand savings are very much linked to engine reliability and are hard to predict early in the project cycle.

Step 6: Determine financial viability

The key steps for the financial appraisal of a proposed cogeneration project are:

Step 6a: Estimate capital cost

Step 6b: Estimate potential savings

Step 6c: Quantify key project parameters

Step 6d: Determine net present value (NPV) and internal rate of return (IRR).

The capital cost estimation used to determine viability of a project should refer to the installed cost of the system, and is typically 1.5 to 3 times the purchase cost of the equipment.

Step 6a: Estimate capital cost

The overall cost of a cogeneration project varies significantly depending on the required plant configuration and its intended physical location.

An approximate capital cost estimate is required to determine the financial viability of the cogeneration project. The capital cost estimation used to determine viability of a project should refer to the installed cost of the system, and is typically 1.5 to 3 times the purchase cost of the equipment.

This multiplier accounts for additional capital expenditure items, such as:

- upgraded electrical system, including interlocks, protection and safety systems
- civil, structural and site preparation
- sound enclosures
- pipework and mechanical plant to utilise the thermal energy in the facilities processes
- controls and automation
- gas supply system, including mains extensions, supply pressure requirements and safety systems
- size and type of installation; for example, small gas engines (< 500 kW output) cost significantly more per unit output than a 1.5 MW output plant.

Table 8 provides indicative installed prime mover capital costs as $/kWe.

Table 8: Indicative $/kWe installed prime mover capital cost estimates

Technology	Capital cost – $ AUD/kWe rated output	Comments
Gas-fired reciprocating engine	$800–$2500	Optimum cost range: engines sized from 1000 to 1500 kWe
Gas turbine (> 1 MW)	$800–$4000	Optimum cost range above 10 MWe
Microturbine (< 1 MW gas turbine)	$1800–$3000	Sizes from 30 to 250 kWe available
Fuel cell (molten carbonate)	$3000–$4000	Sizes from 300 kWe to 3 MWe, with high electrical efficiencies of around 50%. The waste heat is also all available over 400°C so is suitable for steam production.
Steam turbine without boiler plant (> 1 MW)	$300–$1400	Requires high pressure super-heated steam as input. If this is not available the boiler plant will need to be purchased or upgraded. Optimum cost range above 4 MWe
Steam turbine with boiler plant (> 1 MW)	$1000–$3000 (petroleum fuel) $3000–$7000 (high ash/solid fuel/biomass)	Optimum cost range above 4 MWe
Micro steam turbine without boiler plant (< 1 MW)	$1000–$1500	Sizes from 80 kWe to 275 kWe
Organic Rankine cycle	$1000–$3000	Sizes from 80 kWe to 10,000 kWe, with larger units more cost effective

Many factors can influence equipment prices and Table 8 should be viewed as indicative only. Quotes should be sought before making any investment or other significant decisions.

Example

Using Table 8, and assuming an installed capital cost ratio of \$1800/kWe for a gas fired reciprocating engine plant at 600 kWe and \$1200/kWe for 1250 kWe, we can estimate the capital costs of the systems:

- 600 kWe = \$1,080,000 installed system costs
- 1250 kWe = \$1,500,000 installed system costs.

Step 6b: estimate potential savings

Savings are simply the value of the grid electricity and existing thermal plant (such as boilers or hot water heaters) that would be replaced by the cogeneration plant, minus the amount it costs to operate the plant. Cost to operate is determined by two main factors:

- fuel to power the engine
- additional maintenance and operational costs for the plant.

The overall cost for operation over an hour, day, week, month or year can vary significantly depending on the operational profile of the plant. For example, the amount of fuel required will change according to the size and loading of the engine, so loading changes must be taken into account.

For information on maintenance and operating costs (exclusive of fuel costs) see section 10.

To establish the financial benefit, calculate hourly costs versus hourly savings. This enables you to analyse differing operating profiles (i.e. 24 hours, seven days and peak/shoulder) and aggregate annual costs and benefits.

Total costs and total savings calculation method

Total costs per hour = (engine electrical rating x load factor) / engine electrical efficiency x cost of fuel input \$/kWh + (operational and maintenance cost/kWh x engine electrical rating).

Total costs per day = each hourly cost may differ depending on the daily operational profile so each hourly cost needs to be added to get an accurate day cost for that operating profile.

Total savings per hour = electrical savings + thermal savings

Electrical savings = (engine electrical rating x cost of electricity during that hour x load factor for the hour)

\+

thermal savings = (engine rated thermal output x cost of gas/kWh x load factor for the hour x per cent of waste heat recovered / existing plant thermal efficiency [fuel to heating output ratio]).

Net return

These calculations are usually completed using an excel spread sheet.

As cogeneration plants usually require significant capital expenditure and have long plant lives, it is usually more appropriate to use net present value (NPV) and internal rate of return (IRR) as financial metrics to determine viability.

At this point, a simple payback for the project can be determined.

Simple payback: = (project capital investment) / (annual savings)

Most facility managers use simple payback to evaluate and prioritise projects for approval and implementation. While this may work well for organisations that plan only for the short term, it may not be the best way to evaluate projects if you are thinking long term. In fact, most energy saving projects yield benefits over the long term, so if you only use simple payback, you may be oversimplifying the analysis.

Example

Determination of potential savings – soft drink facility cogeneration plant

The method used to assess the viability of the 600 kWe and the 1250 kWe cogeneration systems for the 24 hour period is illustrated in Tables 9–10. Tables 11–13 show calculations for 24 hours, 16 hours and zero hours of manufacturing operation.

Assumptions:

- electricity cost – peak/shoulder (6 am to 10 pm) = $0.10/kWh
- electricity cost – off-peak (10 pm to 6 am) = $0.05/kWh
- gas cost of $6.00/GJ = $0.0216/kWh
- engine operation and maintenance costs are approximately $0.02/kWh
- engine has electrical efficiency of 40% (i.e. the engine produces an energy split of 40% electricity, 40% hot water (heat to power ratio of 1:1) and 20% heat losses (unusable heat)
- 120 x 0 hour non-operational days per year
- 120 x 16 hour operational days per year
- 125 x 24 hour operational days per year
- engine can vary its output down to 50% after which it must be shut down
- existing plant thermal efficiency (e.g. current boiler efficiency) of 80%.

Table 9: Determination of potential savings for 24 hour operation of 600 kWe engine

Item	Method
Step 1: Calculate total costs per hour (the example numbers are for the 600 kWe engine for the hour at 12:00 midday)	= engine electrical rating (600) x load factor (100% = 1) / engine electrical efficiency (40% = 0.4) x cost of fuel input $/kWh. (Gas $0.0216/kWh) + operational and maintenance cost/kWh (0.02) x engine electrical rating (600)) 600 kWe example at 12:00 (600 x (1 / 0.4) x 0.0216) + (0.02 x 600) = $44.40
Step 2: Total costs per day 600 kWe	add the 24 different hourly totals to get savings per day. (Refer Table 11, totals) =$1065.60
Step 3: Calculate total savings per hour (the example given is for the hour at 12:00 midday)	Electrical savings = engine electrical rating (600) x cost of electricity during that hour (.10) x load factor for the hour (100% = 1) + Thermal savings engine rated thermal output (600) x cost of gas/fuel input /kWh (gas $0.0216/kWh) x load factor for the hour (100% = 1) x % of waste heat recovered (100% = 1) / existing plant thermal efficiency [fuel to heating output ratio] 80% = 0.8) 600 kWe example scenario 1 (600 x 0.1 x 1) + (0.0216 x 1 x 1 x 600 / 0.8) = $76.20
Step 4: Total savings per day – 600 kWe	=$1528.80 (add the 24 different hourly totals to get savings per day, refer Table 11, totals)
Step 5: Net return per day (24 h operation) – 600 kWe	Net daily return = total day savings – total day costs =$1528.80 - $1065.60 = $463.20 (refer Table 11, totals)

Table 10: Totals for 1250kWe

Step 1: Total cost per hour (12:00)	= $92.50 (at 12:00)
Step 2: Total costs per day 1250 kWe	= $2193.81 (refer Table 11, totals)
Step 3: Calculate total savings per hour 1250kWe	= $158.75 (refer Table 11, totals)
Step 4: Total savings per day 1250 kWe	= $3147.66 (refer Table 11, totals)
Step 5: Net return per day (24 hour operation) 1250 kWe	=$953.82 (refer Table 11, totals)

Example

Table 11: Net savings for soft drink example on 24 hour operation day and 600 kWe and 1250 kWe engines

	Gas cost	Opex cost	Elec. cost	600 kWe Engine					1250 kWe Engine				
Time	$/Kwh	$/Kwh	$/Kwh	Load factor	% Heat rec	Total costs	Total savings	Net savings	Load factor	% Heat rec	Total costs	Total savings	Net savings
0:00	$0.022	$0.020	$0.050	100%	100%	$44.40	$46.20	$1.80	98%	100%	$91.10	$94.25	$3.15
1:00	$0.022	$0.020	$0.050	100%	100%	$44.40	$46.20	$1.80	89%	100%	$85.05	$85.62	$0.58
2:00	$0.022	$0.020	$0.050	100%	100%	$44.40	$46.20	$1.80	92%	100%	$87.21	$88.70	$1.50
3:00	$0.022	$0.020	$0.050	100%	100%	$44.40	$46.20	$1.80	95%	100%	$88.88	$91.09	$2.21
4:00	$0.022	$0.020	$0.050	100%	100%	$44.40	$46.20	$1.80	96%	100%	$89.96	$92.63	$2.67
5:00	$0.022	$0.020	$0.050	100%	100%	$44.40	$46.20	$1.80	95%	100%	$89.21	$91.55	$2.35
6:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
7:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
8:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
9:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
10:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
11:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
12:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
13:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
14:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
15:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
16:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
17:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
18:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
19:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
20:00	$0.022	$0.020	$0.050	100%	100%	$44.40	$46.20	$1.80	100%	100%	$92.50	$96.25	$3.75
21:00	$0.022	$0.020	$0.050	100%	100%	$44.40	$46.20	$1.80	100%	100%	$92.50	$96.25	$3.75
22:00	$0.022	$0.020	$0.050	100%	100%	$44.40	$46.20	$1.80	100%	100%	$92.50	$96.25	$3.75
23:00	$0.022	$0.020	$0.050	100%	100%	$44.40	$46.20	$1.80	96%	100%	$89.91	$92.55	$2.65
					Totals	$1,065.60	$1,528.80	$463.20		Totals	$2,193.81	$3,147.66	$953.85

Table 12: Net savings for soft drink example on 16 hour operation day, 600 kWe and 1250 kWe engines

	Gas cost	Opex cost	Elec. cost	600 kWe Engine					1250 kWe Engine				
Time	$/Kwh	$/Kwh	$/Kwh	Load factor	% Heat rec	Total costs	Total savings	Net savings	Load factor	% Heat rec	Total costs	Total savings	Net savings
0:00	$0.022	$0.020	$0.050	56%	0%	$30.09	$16.75	-$13.34	0%	0%	$-	$-	$-
1:00	$0.022	$0.020	$0.050	54%	0%	$29.33	$16.05	-$13.28	0%	0%	$-	$-	$-
2:00	$0.022	$0.020	$0.050	54%	0%	$29.50	$16.20	-$13.30	0%	0%	$-	$-	$-
3:00	$0.022	$0.020	$0.050	57%	0%	$30.41	$17.05	-$13.36	0%	0%	$-	$-	$-
4:00	$0.022	$0.020	$0.050	0%	0%	$-	$-	$-	0%	0%	$-	$-	$-
5:00	$0.022	$0.020	$0.050	100%	83%	$44.40	$43.50	-$0.90	76%	40%	$76.46	$57.94	-$18.52
6:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	92%	100%	$87.21	$146.30	$59.10
7:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	95%	100%	$88.88	$150.24	$61.36
8:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	96%	100%	$89.96	$152.78	$62.82
9:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	95%	100%	$89.21	$151.00	$61.80
10:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
11:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
12:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
13:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
14:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
15:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
16:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
17:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
18:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
19:00	$0.022	$0.020	$0.100	100%	100%	$44.40	$76.20	$31.80	100%	100%	$92.50	$158.75	$66.25
20:00	$0.022	$0.020	$0.050	100%	100%	$44.40	$46.20	$1.80	100%	100%	$92.50	$96.25	$3.75
21:00	$0.022	$0.020	$0.050	100%	100%	$44.40	$46.20	$1.80	100%	100%	$92.50	$96.25	$3.75
22:00	$0.022	$0.020	$0.050	100%	100%	$44.40	$46.20	$1.80	88%	96%	$84.56	$83.74	-$0.82
23:00	$0.022	$0.020	$0.050	64%	0%	$32.79	$19.25	-$13.54	0%	0%	$-	$-	$-
					Totals	**$951.32**	**$1,334.20**	**$382.88**		**Totals**	**$1,626.28**	**$2,522.01**	**$895.73**

Table 13: Net savings for soft drink example on non-operational day – 0 hour operation, 600 kWe and 1250 kWe engines

	Gas cost	Opex cost	Elec. cost	600 kWe Engine					1250 kWe Engine				
Time	$/Kwh	$/Kwh	$/Kwh	Load factor	% Heat Rec	Total costs	Total savings	Net savings	Load factor	% Heat rec	Total costs	Total savings	Net savings
0:00	$0.022	$0.020	$0.050	54%	0%	$29.50	$16.20	-$13.30	0%	0%	$-	$-	$-
1:00	$0.022	$0.020	$0.050	57%	0%	$30.41	$17.05	-$13.36	0%	0%	$-	$-	$-
2:00	$0.022	$0.020	$0.050	0%	0%	$-	$-	$-	0%	0%	$-	$-	$-
3:00	$0.022	$0.020	$0.050	0%	0%	$-	$-	$-	0%	0%	$-	$-	$-
4:00	$0.022	$0.020	$0.050	0%	0%	$-	$-	$-	0%	0%	$-	$-	$-
5:00	$0.022	$0.020	$0.050	50%	0%	$28.25	$15.05	-$13.20	0%	0%	$-	$-	$-
6:00	$0.022	$0.020	$0.100	54%	0%	$29.33	$32.10	$2.77	0%	0%	$-	$-	$-
7:00	$0.022	$0.020	$0.100	54%	0%	$29.55	$32.50	$2.95	0%	0%	$-	$-	$-
8:00	$0.022	$0.020	$0.100	76%	0%	$36.62	$45.60	$8.98	0%	0%	$-	$-	$-
9:00	$0.022	$0.020	$0.100	100%	0%	$44.29	$59.80	$15.51	0%	0%	$-	$-	$-
10:00	$0.022	$0.020	$0.100	92%	0%	$41.81	$55.20	$13.39	0%	0%	$-	$-	$-
11:00	$0.022	$0.020	$0.100	94%	0%	$42.46	$56.40	$13.94	0%	0%	$-	$-	$-
12:00	$0.022	$0.020	$0.100	87%	0%	$40.08	$52.00	$11.92	0%	0%	$-	$-	$-
13:00	$0.022	$0.020	$0.100	90%	0%	$41.21	$54.10	$12.89	0%	0%	$-	$-	$-
14:00	$0.022	$0.020	$0.100	85%	0%	$39.65	$51.20	$11.55	0%	0%	$-	$-	$-
15:00	$0.022	$0.020	$0.100	82%	0%	$38.41	$48.90	$10.49	0%	0%	$-	$-	$-
16:00	$0.022	$0.020	$0.100	97%	0%	$43.37	$58.10	$14.73	0%	0%	$-	$-	$-
17:00	$0.022	$0.020	$0.100	75%	0%	$36.41	$45.20	$8.79	0%	0%	$-	$-	$-
18:00	$0.022	$0.020	$0.100	67%	0%	$33.65	$40.10	$6.45	0%	0%	$-	$-	$-
19:00	$0.022	$0.020	$0.100	60%	0%	$31.39	$35.90	$4.51	0%	0%	$-	$-	$-
20:00	$0.022	$0.020	$0.050	57%	0%	$30.47	$17.10	-$13.37	0%	0%	$-	$-	$-
21:00	$0.022	$0.020	$0.050	64%	0%	$32.79	$19.25	-$13.54	0%	0%	$-	$-	$-
22:00	$0.022	$0.020	$0.050	56%	0%	$30.09	$16.75	-$13.34	0%	0%	$-	$-	$-
23:00	$0.022	$0.020	$0.050	54%	0%	$29.33	$16.05	-$13.28	0%	0%	$-	$-	$-
					Totals	$739.08	$784.55	$45.47		Totals	$-	$-	$-

Example

These tables show that the:

- savings are significantly reduced during off-peak electricity periods
- plant is costing rather than saving money when the thermal energy is not fully recovered
- larger 1250 kWe engine is unable to operate and generate savings for significant periods because the electrical load is less than the engine's minimum operating load.

Therefore, operational decisions such as whether to operate the plant during off-peak periods need to be made. There are two key financial cases to assess:

- running the plant during off peak
- not running the plant during off peak.

The net savings for each potential operating regimes and engine sizes are calculated as follows:

600 kWe engine operating during peak and off-peak hours:

= (125 (24 hour days) x $463.20) + (120 (16 hour days) x $382.88) + (120 (0 hour days) x $45.47)

= $109,302 per annum

600 kWe engine operating during peak hours only:

= (125 x 14 (peak and shoulder hours per day) x $31.80) + (120 x 14 x $31.80) + (120 x 14 x $9.92) (average peak and shoulder energy saving outside production)

= $125,740 pa

1250 kWe engine operating during peak and off-peak hours:

= 125 x $953.85 + 120 x $895.73 + 120 x $0.00

= $226,719 per annum

1250 kWe engine operating during peak hours only:

= (125 x 14 x $66.25) + (120 x 14 x $ 64.83 (average savings peak and shoulder)) + (120 x 14 x $0.00)

= $224,851 per annum

Therefore the best operational profiles for each size system are:

- 600 kWe engine operating during peak hours only – $125,470
- 1250 kWe engine operating during peak and off-peak hours – $226,719.

Now we can make simple payback calculations based on the best operational cases for both engine sizes and the associated demand savings.

600 kWe operating in peak hours only:

= $1,080,000/ ($125,740 (grid offset savings) + $67,200 (demand savings – see step five))

= 5.6 years

1250 kWe operating during peak and off-peak:

= $1,500,000 / ($226,719 + $140,000 (demand savings – see step five))

= 4.1 years

In this case, the most financially attractive cogeneration system using simple payback is a 1250 kWe engine operating in peak and off-peak periods with a simple payback of 4.1 years.

As can be seen in the worked example, the operating strategy affects the financial outcomes, so you may need to test several combinations of sizing and operational strategy.

For trigeneration, an additional annual electricity cost for conventional grid supply of the electric chiller is calculated for peak, shoulder and off-peak periods as:

Grid electricity offset = (trigeneration thermal output) x (absorption chiller COP / electric chiller COP) x (operating hours) x (electricity tariff)

Step 6c: Quantify key project parameters

Net present value (NPV) is a financial tool used to determine the overall value of a project (or a series of cash flows). NPV represents the value in today's dollars of all future cash flows. Some key parameters that are usually required to conduct an NPV are below:

- facility life – typically up to 20 years
- depreciation – for example, linear for 20 years to zero residual value
- discount rate (or discount factor) – dependent on minimum attractive rate of return (MARR). Every company has a MARR and it basically means that they can invest and earn this rate elsewhere, so your project must have a return greater than the MARR. A common discount rate is seven per cent
- construction period – typically, 24 months from commencing feasibility study to handover of operating plant to operations
- additional funding or grants.

Step 6d: Determine NPV and IRR

The next step is to estimate the cash flow generated with capital cost at year zero and net savings each year over the project lifetime, by applying assumptions for escalating energy tariffs as well as operating and maintenance costs. The payback period, NPV and internal rate of return (IRR) of the cogeneration project cash flow are then determined to complete the base case financial appraisal. For information on how to conducting NPV analysis using excel please see: office.microsoft.com/en-au/excel-help/npv-HP005209199.aspx

A sensitivity analysis should be completed to test the impact of changing key input variables on the project payback, NPV and IRR. For example, what is the impact on the NPV if gas price was to double over the next five years? The calculations are conducted again using an increasing gas price and the results noted. Key inputs to be tested include:

- capital cost
- electricity tariffs
- natural gas tariffs
- waste heat utilisation
- maintenance costs
- operating hours.

There are numerous methods for financing cogeneration projects that can include grants and funding schemes, see section 11 for more details.

The financial metrics for the bottling facility example, with the 600 kWe engine operating only during peak periods and the 1250 kWe operating for 24 hours, are shown in Table 14.

Table 14: Summary of results with discount rate of seven per cent

Discount rate of 7%	600 kWe peak and shoulder	1250 kWe 24 hours
IRR	21.29%	32.04%
NPV – project life (20 years)	$755,547	$1,873,968
NPV at 10 years	$298,472	$1,120,049
Simple payback (years)	5.6	4.1

From this analysis, it is clear that the best financial option would be the 1250 kWe system.

Example

Additional financial benefits

There are a number of benefits typically associated with cogeneration projects that should be included in the financial viability analysis. These include:

- potential access to energy efficiency project funding
- reduction in carbon dioxide emissions and reduced exposure to the carbon price
- potential reduction in site ancillary utility infrastructure capital requirements, such as a reduction in steam/hot water generation capacity and a reduction in peak demand capacity of electricity connection
- improvement of building NABERS rating (refer to Appendix 7) which can increase rental income and/or qualify the premises for rental by organisations requiring a minimum NABERS rating.

These benefits may contribute significantly to building a successful business case. However, as these benefits are very site specific, they are not estimated in this guide

Step 7: Calculate the reduction in greenhouse gas (GHG) emissions

Significant GHG emissions can be saved by implementing cogeneration/trigeneration. The GHG savings predominantly come from replacing a CO2-intensive fuel source (coal) with a less intensive the main fuel source for electricity generation (natural gas).

Always check for the most up-to-date factors when performing GHG calculations. These can be found at www.climatechange.gov.au/publications/greenhouse-acctg/national-greenhouse-factors.aspx.

Reductions in GHG emissions could lead to additional benefits in improving environmental green ratings for the site (Appendix 7).

The greenhouse gas savings can be calculated by:

GHG savings = (offset grid GHG – cogeneration gas fuel GHG) + heat recovered for boiler offset GHG.

Step 1: Determine the total electrical output of the cogeneration plant

Step 2: Determine the cogeneration gas consumption in gigajoules, high heating value (HHV) basis

Step 3: Calculate GHG in kg CO2-e for the cogeneration gas consumption

Step 4: Calculate GHG in kg CO2-e for sourcing this generated electricity from the grid if no cogeneration plant was installed

Step 5: Calculate boiler GHG emission reduction

Step 6: GHG savings = cogeneration GHG – grid GHG – boiler GHG.

Example

Calculation of GHG emissions for the soft drink facility

For the bottling facility example, a 1250 kWe engine is operated during peak electricity tariff periods only. The greenhouse gas savings are calculated to be 4,797 tonnes per annum. The calculation is shown below.

Step 1: Determine the total electrical generation of the cogeneration per year

Total generation = 6,303,000 kWh

Step 2: Determine the annual cogeneration gas consumption in GJ HHV basis

Gas consumption = 56,727 GJ

Step 3: Calculate GHG in kg CO_2-e for the cogeneration gas consumption using *National Greenhouse Accounts Factors July 2012*. From their Tables 2 and 37, emission factors 51.33 kg CO_2-e / GJ (scope 1) + 14.2 kg CO_2-e / GJ (scope 3)
= 65.53 kg CO_2-e / GJ (scope 1+3)

Cogeneration GHG = 56,727 GJ x 65.53 kg CO_2-e / GJ
= 3,717,320 kg CO_2-e pa

Step 4: Calculate GHG in kg CO_2-e for sourcing this generated electricity from the grid using *National Greenhouse Accounts Factors July 2012*. From their Table 40, NSW grid factor of 1.06 kg CO_2-e / kWh (scope 2+3)

Grid offset GHG = 6,303,000kWh x 1.06 kg CO_2-e / kWh
= 6,681,180 kg CO_2-e pa

Example

Step 5: Calculate boiler GHG emission reduction using *National Greenhouse Accounts Factors July 2012*. Natural gas factor of 51.33 kgCO_2/GJ.

Note: the boiler efficiency to calculate the fuel consumption of a gas fired boiler (in GJ HHV) is also applied.

Heat recovery boiler load offset = (125 days x 1250 kW x 0.0036 GJ/kWh x 24 h/day x 100%) + (120 x 1250 kW x 0.0036 x 24 x 70% [average thermal utilisation]) + (120 x 1250 kW x 0.0036 x 24 x 0%) x 65.53 kg CO_2-e / GJ

= 1,467,180 kg CO_2-e pa

Correcting for boiler efficiency = 1,467,180 / 80% (HHV basis) = 1,833,975 kg CO_2-e pa

Step 6: GHG savings = (grid GHG – cogeneration GHG) + heat recovered boiler offset GHG

GHG savings = (6,681,180 – 3,717,320) +1,833,975 = 4,797,835 kg CO_2-e pa.

Trigeneration GHG emissions reduction

GHG emissions reduction from trigeneration can be calculated similarly.

Step 1: Determine the total electrical generation of the trigeneration

Step 2: Calculate grid GHG in kg CO2-e for sourcing this generated electricity from the grid using NGA NSW grid factor of 1.06 kg CO2-e / kWh

Step 3: Determine the total cooling duty produced by the absorption chiller in kWh

Step 4: Calculate the electric chiller GHG emissions offset using the NGA NSW grid factor of 1.06 kg CO2-e / kWh. This can be done by firstly applying the COP of an electric chiller suited to the cooling duty to the total cooling duty produced by the absorption chiller to calculate the electrical consumption offset by the absorption chiller and then multiplying this consumption offset by 1.06 kg CO2-e / kWh

Step 5: Calculate the displaced value of refrigeration gases HFC R134a or R22 that would have otherwise been used in the electric chiller

Step 6: Calculate the trigeneration fuel consumption in GJ HHV basis

Step 7: Calculate the trigeneration GHG emissions using NGA natural gas factor of 65.53 kg CO2-e / GJ

Step 8: GHG savings = offset amount of grid GHG – trigeneration produced GHG + electric chiller offset GHG production

Additional GHG reductions using trigeneration

Using trigeneration to replace electric chillers can have an additional GHG reduction benefit. Electric chillers typically use fluorocarbon refrigerants such as HFC 134a which has a global warming potential of 3830 over 20 years or 1300 after 100 years. According to *Australian National Greenhouse Accounts Factors 2012* (Tables 24 and 26), the leakage rate for HFC refrigerants is nine per cent a year. Heat-fired absorption chillers on the other hand use refrigerants with zero potential for ozone depletion potential or global warming such as lithium bromide and water or ammonia and water, representing an additional reduction in GHG emissions.

Table 15 below illustrates typical GHG savings achievable by cogeneration and trigeneration for a number of configurations. Note that the percentage GHG saving is only on the portion of energy supplied by the cogeneration or trigeneration plant and does not apply to the entire energy consumption of the facility. GHG savings reduce if the waste heat generated from the plant is not fully utilised.

Table 15: Greenhouse gas emission savings for cogeneration and trigeneration (100% of recovered heat utilised)

Configuration	Generator type	Electrical [kWe]	Heat [kWt]	Cooling [kWr]	GHG saving [%]
Cogeneration (hot water)	Reciprocating engine	1000	1100	–	54
Cogeneration (steam)	Gas turbine	5000	8500	–	49
Cogeneration (hot water)	Microturbine	100	138	–	42
Cogeneration (LT + HT hot water)	Fuel cell	400	450	–	55
Cogeneration (HT hot water)	Fuel cell	400	138	–	47
Trigeneration	Reciprocating engine	1000	–	800	50

Notes:

1. Waste heat utilisation assumed to be 100%
2. Boiler efficiency assumed 80% HHV
3. Electric chiller COP assumed 5.0.
4. Absorption chiller COP assumed 0.73.

Step 8: Compare with green power

If the objective is to reduce carbon emissions in the most cost-effective way, cogeneration may not be as cheap as purchasing green power. A comparison is necessary.

Green power electricity is generated from renewable sources such as solar, wind, hydro, biogas and biomass, and so it has zero or minimal carbon emissions. Green power costs 5–8 c/kWh more than regular electricity tariffs for 100 per cent green power.

To compare cogeneration and green power:

- determine the capital cost and net energy savings (energy savings less cogeneration operating cost) for the proposed cogeneration plant based on regular tariffs (i.e. zero per cent green power)
- calculate the NPV of the proposed cogeneration over the plant lifetime
- calculate the NPV of purchasing 50 per cent green power – likely to be 2.5–4.0 c/kWh more than regular tariffs over an equivalent timeframe
- If NPV (green power) is less than NPV (cogeneration), then green power is a more cost-effective way to reduce GHG emissions.

Green power cost calculation – soft drink facility

Example

Assumptions:

- a 1250 kWe cogeneration plant installed
- the cogenerated electricity cost, including all operating costs, weighted average costs of capital and deprecation costs is $0.13/kWh
- the engine produces 6,303,000 kWh p.a. and the carbon footprint of the electricity is 0.53 kg CO_2-e / kWh (50 per cent reduction compared to grid power at 1.06 kg CO_2-e / kWh)
- the cost of green power is $0.17/kWh and it has zero GHG emissions.

Hence, the quantity of green power required to give the same GHG reduction as the cogeneration plant is:

(1 – 0.53/1.06) (equivalent amount of carbon neutral power) x 6,303,000 kWh (cogenerated energy)

= 3,151,500 kWh p.a. (49% of total consumption)

Cost of green power = 3151500 kWh x $0.17/kWh = $535,755 p.a.

Cost of cogenerated electricity = 6303000 kWh x $0.13/kWh = $819390 p.a.

Hence, the cogenerated electricity has a higher total cost. The soft drink facility would therefore be better off purchasing green power if GHG reduction was the only objective.

If the energy savings achieved by cogeneration are not sufficient to justify the capital investment, green power may be a more cost-effective way to reduce GHG emissions.

The design of a specific cogeneration system requires selecting and deciding from numerous alternatives, with the final system specification a result of extensive trade-off analyses.

5 Connection to the electricity grid

The selection of the connection method can significantly affect the complexity, timeframe and costs associated with the grid connection and can therefore affect the overall feasibility of cogeneration for the particular site.

The costs of required network augmentations in some locations may severely affect the viability of the generating scheme and it is essential to consult the DNSP early in the planning process to identify any network constraints.

All cogeneration system configurations interact with the electricity grid: as backup in case of failure and to supply electricity when the cogeneration system does not supply the full electricity load of the facility.

Connecting a cogeneration system to the electricity grid requires careful consideration of the available options, including the following:

- generator connection point
- generator and connection voltages (low voltage (LV) or high voltage (HV))
- if export of power to the grid is required (refer to section 5.2)
- if operation in island mode is required (refer to section 5.3).

The selection of the connection method can significantly affect the complexity, timeframe and costs associated with the grid connection and can therefore affect the overall feasibility of cogeneration for the particular site.

For example, the maximum capacity of a generating installation that could generally be connected to the low voltage network is around 1.5 MVA. Larger generators require extensive system studies that can be both costly and time-consuming. The costs of required network augmentations in some locations may severely affect the viability of the generating scheme and it is essential to consult the DNSP early in the planning process to identify any network constraints.

Each individual cogeneration scheme has unique technical and commercial characteristics, so it is not possible to provide specific guidelines and solutions for the design of connection arrangements. Instead, this section of the guide will give you a general understanding of the connection process and the main issues which affect the design and cost of cogeneration connections

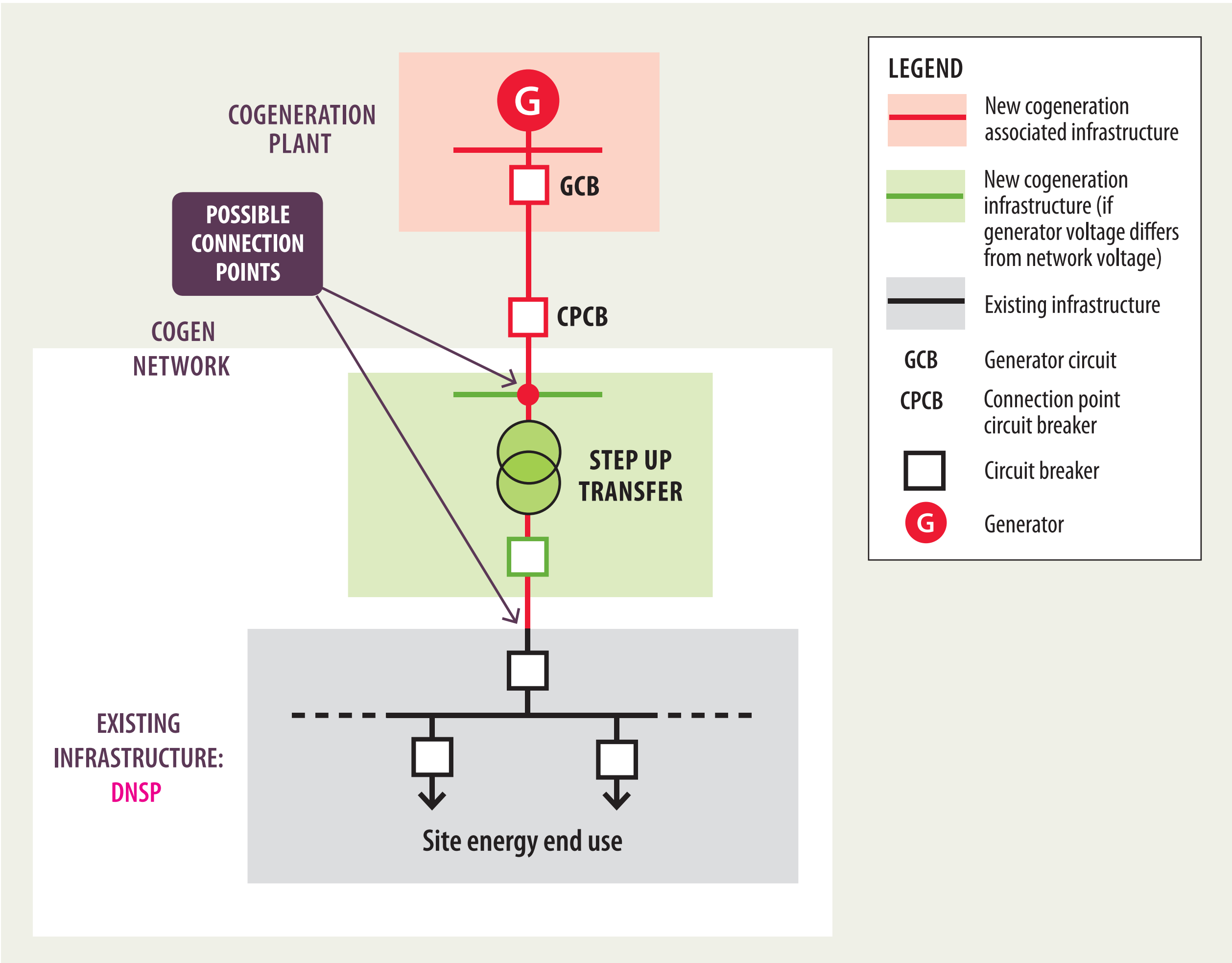
5.1 Parallel connection

Connection in parallel is the most common form of connection. The cogeneration unit and the grid are synchronised so that the site can receive electricity from the grid and the cogeneration unit at the same time. This would occur with all base-load sized cogeneration units.

A typical cogeneration connection arrangement is shown below in Figure 21. The step-up transformer shown may not be required if the generator voltage is the same as the network voltage at the network connection point. It is important to check that it is technically possible to connect all switchboards and loads that have been included in the feasibility study.

The voltage of the cogeneration unit is typically determined by two factors: the voltage required at the point of connection (to avoid additional cost of transformers) and the voltage available from the prime mover technology selected (e.g. smaller generators may only be available in low voltages).

Figure 21: Typical single line diagram of cogeneration plant electrical connection



5.2 Exporting electricity to the grid

Most cogeneration schemes operate in parallel to the grid but do not export electricity to it. Generally, the cogeneration plant is sized to operate continuously at high load to satisfy the base load requirements for the site, with load variations above the base load being met by electricity imported from the grid. This configuration is generally the most economic.

If the capacity of the cogeneration plant is greater than the customer's on-site load demand, it may be possible for any excess electricity generated to be exported to the grid. This arrangement would be subject to agreement for the additional technical requirements with the DNSP and negotiation of a satisfactory energy purchase agreement with the retailer.

It is more technically complicated to connect a generator that can export electricity to the network than it is to connect a load or a generator that will not export and that addressing these technical requirements can be expensive. Furthermore, the operating cost for generating electricity is likely to be higher than the pricing received for energy exported to the grid, making grid export generally uneconomic.

Currently, exporting to the grid requires an electrical retail license (i.e. you become the equivalent of an electricity retailer). Currently, there is considerable discussion as to how this is processed.

The decision over whether or not to export electricity to the grid is primarily a commercial decision, to be made after careful consideration of the additional costs and other factors associated with exporting.

Currently exporting power is generally not feasible as the price received for the power exported to the grid is less than the cost to produce it. Exporting energy has specific licensing and regulatory issues that make it more complex and costly to connect to the grid. However, exporting of power can be financially viable under some contractual arrangements. This would typically only occur in a scenario where the cogeneration plant was constructed under a build, own and operate agreement (for more details see section 11) by a business that has a relationship with a network company and sells the outputs to customers under a specific agreement. In this arrangement, because the network company allows the energy to be exported, it can be supplied back to the same customer or another customer at a previously agreed rate. This may make the system financially viable. It may also be viable for shopping centres which are allowed to run embedded networks and on-sell electricity generated to its retail customers without requiring an electrical retail license.

5.3 Islanding

Islanding refers to a situation where the cogeneration system separates from the normal power system and then continues to operate independently of the normal power system. For example, this may happen when a fault or disturbance on the network trips circuit breakers that separate the cogeneration connection from the network.

Operation in islanded mode of cogeneration systems (of the scale discussed in this guide) is typically not considered viable, as DNSPs such as Ausgrid, Endeavour Energy and Essential Energy require increased safety and supply quality issues associated with islanding operation.

Cogeneration schemes intended for islanding operation must be approved by the DNSP and will require additional systems to be in place to ensure the following:

- the generator must be disconnected before the islanded section of network is reconnected to the rest of the network; or
- synchronising facilities must be installed to ensure the cogeneration system is synchronised to the network when it re-connects.

Example

Exporting electricity is not economically feasible and the ability to operate island mode is not required. Therefore this plant will run in parallel. A gas engine generator of 1250 kWe will connect at low voltage and will generate three-phase power at 415 V. The connection costs and timeframes were kept to a minimum as the DNSP was contacted early and they were provided with all the relevant electrical information from site, including fault levels, equipment current ratings and existing switchboard protection. The connection was approved and the plant can now be connected to a 415 V switchboard.

5.4 Connection process

The process for connecting cogeneration to the electricity grid is set out in the National Electricity Rules (NER). The process is generally seen as being complex, inefficient, costly and slow. In June 2012, the Australian Energy Market Commission (AEMC) published a consultation paper about proposed changes to the rules to create a timelier, clearer and less expensive process for connecting embedded generators to distribution networks. The AEMC consultation paper and associated documents, including submissions from interested parties, are available on the AEMC website:

www.aemc.gov.au/Electricity/Rule-changes/Open/connecting-embedded-generators.html

As the current regulations concerning the connection process are likely to change, you should consult AEMC and your DNSP early in the process, to establish what is needed in your specific situation.

The basic process involves the following main steps.

Step 1: A connection enquiry is submitted to the DNSP, setting out details of proposed cogeneration system.

Step 2: A connection enquiry response is received from the DNSP, setting out connection options and associated information.

Step 3: An application for connection is submitted to the DNSP, setting out final details and requirements for the cogeneration system.

Step 4: An offer to connect is received from the DNSP, setting out requirements and design information for any required connection works.

Step 5: A connection agreement is completed.

Step 6: Construction, testing and commissioning.

Additional information regarding connection regulations can be found in section 8.

The above process applies to most cases. However, it may vary significantly in terms of the level of information required, with complexity generally increasing with connection capacity.

Additional information regarding regulatory requirements related to electricity connections can be found in section 8.

5.5 Technical considerations

Connecting a cogeneration scheme to an electricity distribution network will affect the operation and performance of the network. The DNSP is responsible for maintaining network safety and ensuring that operation of the cogeneration scheme does not cause problems for nearby electricity users such as voltage disturbances or spikes on the network.

Particular technical considerations for cogeneration connections include the following:

1. Connection voltage

Due to network limitations, the maximum capacity of a generating installation that can generally be connected to the LV network is around 1.5 MVA. Generators above this size must generally be connected to the HV network, with consequently more complex connection requirements. A transformer may be required to convert between the generator voltage and the connection voltage.

2. Equipment full load current ratings

The existing and new infrastructure must be capable of carrying the current output from the generator. This may require replacement or upgrading of existing equipment such as switchboards and circuit breakers.

3. Fault levels

Connecting a generator to a distribution network can increase the fault levels in the network close to the point of connection. The addition of new generation to an existing network may increase fault levels beyond the fault ratings of currently connected equipment, resulting in the need to upgrade existing equipment or provide additional equipment to reduce the fault contribution from the generator. You should measure and understand your existing fault levels before engaging the DNSP on connection. This can be done by most electrical contractors or engineers.

To speed up the connection process you should measure and understand your existing fault levels before engaging the DNSP on connection. This can be done by most electrical contractors or engineers.

4. Protection requirements

Protection systems are required for the generating system itself as well as to ensure the stability and security of the distribution network to which the generator is connected. In general, the protection requirements will become more complex the larger the generating capacity and the higher the connection voltage.

5. Generator synchronisation

It is important that a generator is fully running and synchronised with the external power network before it is physically connected, so that no equipment is damaged. Generator synchronisation involves making sure that the:

- voltage level of generation matches the voltage level of the external network
- frequency of generation matches the frequency of the external network
- generator is in phase with the external network.

Synchronisation requires more complex controls than are required for a standard backup generator.

5.6 Reference documents

Key reference documents on the connection of cogeneration plants to distribution networks are:

- *Embedded Generation Connection guide* – Clean Energy Council
- *Technical Guide for Connection of Renewable Generators to the Local Electricity Network* – Australian Business Council for Sustainable Energy (BCSE)
- *NS194 Connection of Embedded Generators*, August 2008 – Ausgrid
- *CEOP 8012 Generation Connection: Protection Guidelines* – Essential Energy
- *Network Connection Contestable Works General Requirements (SPJ 4004-2)*– Endeavour Energy
- *Endeavour Energy Standard Form Connection Contract for Connection Points with Exempt Generation* – Endeavour Energy.

For more information on compliance and regulations regarding connection please refer to section 8.3.

6 Natural gas network connection

The two key technical parameters for the natural gas supply are the:

- connection capacity
- gas supply pressure.

Connection capacity

Typical natural gas requirements in gigajoules per hour (GJ/h) for gas engines, gas turbines, microturbines and fuel cells for a range of generator outputs are given in appendix two. The total natural gas supply requirement, or connection capacity, for a facility must also allow for all other gas users at the facility.

The facility owner will need to confirm the following with the gas supplier:

- capacity of existing metering station for the total gas requirement
- ability of the gas supply network to cope with the required maximum flow of gas.

If the existing gas metering station and/or the supply network do not have sufficient capacity, the facility owner will need to clarify the scope and cost of the required upgrade to the gas supply. Augmentation work is usually expensive and may rule out a potential cogeneration project.

Supply pressure

The NSW natural gas network configuration operates at a range of pressures, from 6895 kPa on the Moomba to Sydney trunk main down to 2 kPa on low-pressure distribution mains (see Figure 22).

Typical pressure requirements for cogeneration technologies are:

- gas reciprocating engines 10–20 kPa
- gas turbines 1500–2500 kPa
- microturbines 500–650 kPa
- fuel cells 2–20 kPa.

The natural gas supply pressure to most facilities is typically sufficient for gas engines and fuel cells, which have relatively low pressure requirements. If your facility is not currently supplied from a primary main, a gas turbine may require either a new gas connection or gas compression within the facility, which will affect the viability of the cogeneration project. Unless you are a major gas consumer, it is most unlikely that your gas connection is from a primary main.

A new gas connection will probably require connection to a higher pressure gas main and a new metering station at the facility. This cost may be high and cast doubt on the viability of a cogeneration project.

Best practice would involve using renewable fuel options, such as biogas from biodigesters, which can be free and further reduce equivalent carbon dioxide emissions.

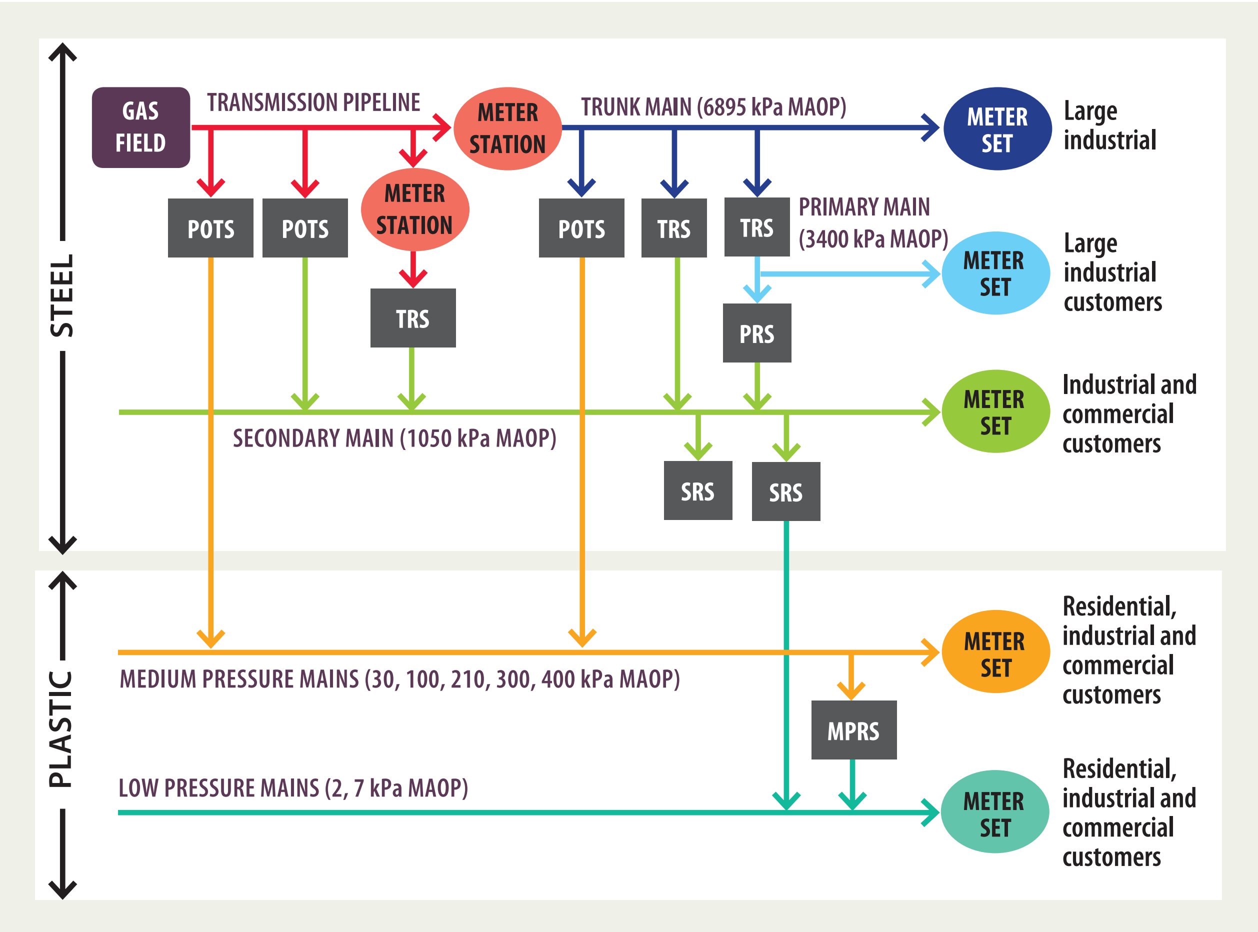
The installation of gas compression would typically involve two gas compressors driven by electric motors installed close to the cogeneration plant. One compressor would normally be in operation with the second acting as a standby or undergoing maintenance. The capital and operating (maintenance and auxiliary load) costs of the compressors must be included in the cogeneration project evaluation.

For a microturbine application it is likely that gas compression (fuel gas booster) will be required. This is typically available from the microturbine supplier as an integrated option.

Example

The site already receives natural gas from the mains. The 1250 kWe gas engine requires 15 kPa pressure. The site confirmed with the gas supplier that the supply capacity and pressure are sufficient without the need for augmentation work.

Figure 22: NSW natural gas network configuration



7 Electricity and gas tariff forecasts

Electricity and gas tariff forecasts ensure that the difference between the price of grid electricity and that of natural gas is considered for the full lifetime of your cogeneration project.

There could be changes to key electricity supply contract parameters caused by a cogeneration project and these need to be taken into consideration. For example, a reduction in energy imported from the grid (kWh) may affect the energy tariff. Introducing cogeneration will usually reduce demand (kVA), but as demand tariffs are levied on peak demand (over a month or 12-month period), the effect may not be seen in the early billing periods.

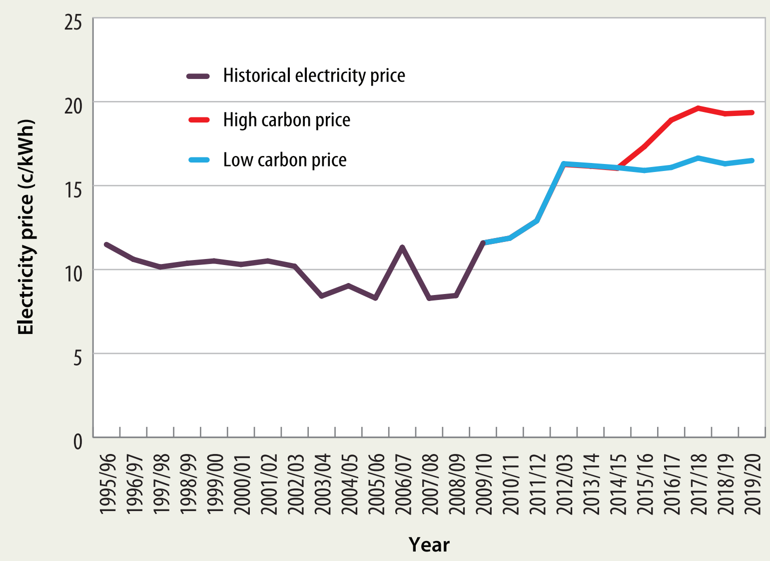
You should discuss all charges, particularly maintenance outages and peak demand charge periods, with your electricity retailer.

The cogeneration plant may have maintenance outages (both scheduled and breakdowns) and occasional trips, initiated by the cogeneration plant's protection systems, during which supply of electricity from the grid may set the facility peak demand. The number of maintenance outages and trips likely to occur in a year must be estimated to assess the extent of reduction of demand charges. You should discuss all these charges, particularly maintenance outages and peak demand charge periods, with your electricity retailer.

7.1 Overall range of expected electricity price increases

An overview of historical and near-term electricity prices is shown in Figure 23.

Figure 23: NSW business electricity prices 1995–2020 (2011–2012 $)



Source: Ison, N. and Rutovitz, J. 2011. *NSW Business Energy Prices 2000–2020*. Institute for Sustainable Futures, University of Technology, Sydney.

A cogeneration project is typically evaluated over a lifetime of 10–20 years, so escalation estimates should be applied to electricity tariffs beyond the existing electricity supply contract period. The escalation applied can use simple Consumer Price Index (CPI) or public domain reports for small projects or electricity market modelling by specialist consultants for larger projects.

7.2 Forecast range of natural gas price increases

Like electricity, the retail price of natural gas has a number of components. Price may also depend on the quantity of gas used with larger consumers potentially able to negotiate lower rates. The main components of gas price are:

- wholesale gas price
- network charges, including transmission and distribution
- retail costs and margins.

Forecasting gas prices is similar to forecasting electricity prices. Figure 24 shows one forecast.

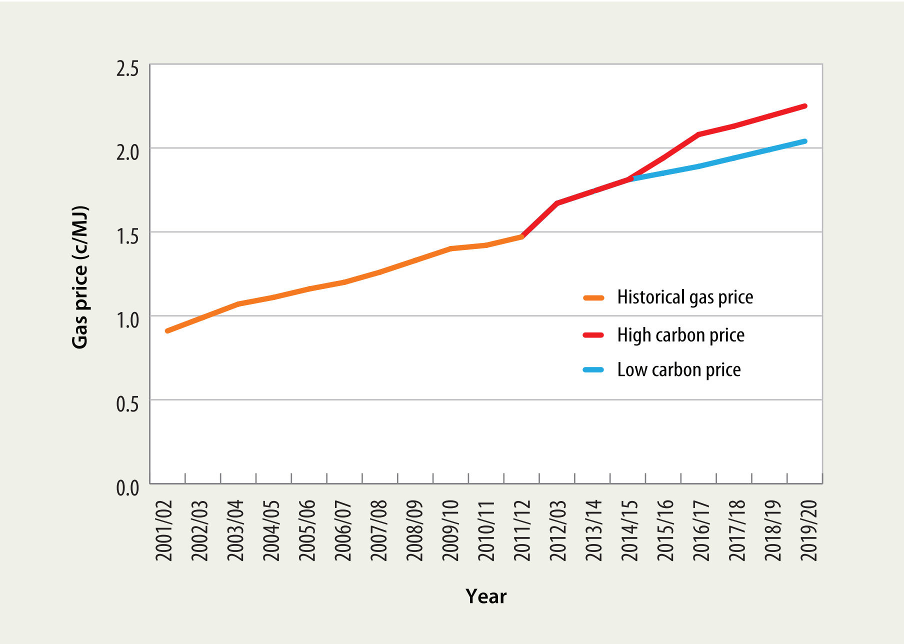


Figure 24: NSW business gas prices 2001–2020 (2011–2012 $)

Source: Ison, N. and Rutovitz, J. 2011. *NSW Business Energy Prices 2000–2020*. Institute for Sustainable Futures, University of Technology, Sydney.

A public domain forecast for NSW energy prices to 2020 for medium to large business users is available within *NSW Business Energy Prices to 2020* published by the Institute for Sustainable Futures.

Variations of future gas and electricity prices should be put through a sensitivity analysis to see what impact these changes make to the financial business case. For example, if gas was to triple in price over 20 years but electricity prices stayed the same, how would that affect your business case?

8 Regulations and approvals requirements

This section details the basic approvals and regulations relevant to a cogeneration installation, including:

- development approval and environmental consents
- air emissions regulations
- electrical connection.

Obtaining all approvals is necessary for the project to proceed and compliance with all regulations is required prior to operation.

8.1 Development approval and environmental consents

A cogeneration project in NSW may require a development approval and an environmental consent.

Land use zoning

State Environmental Planning Policy (Infrastructure) 2007

This policy permits electricity generating works including cogeneration with development consent in prescribed zones (rural, industrial or special-use land use zones) across the state.

Local Environmental Plans (LEP)

Each council has its own zoning plan (i.e. an LEP), which may indicate additional zones where cogeneration can be permitted with development consent. Often cogeneration is prohibited in residential and other sensitive land use zones.

Step one – Development Consent

Cogeneration requires development consent either from the Minister for Planning and Infrastructure or local council.

State Significant Development

A cogeneration project is a 'State Significant Development' if it has an estimated capital investment value of greater than $30 million, (or greater than $10 million if the unit is to be located in an environmentally sensitive area). State Significant Developments need consent from the Minister for Planning and Infrastructure and a development application must have an Environmental Impact Statement (EIS).

Local Development

If your cogeneration project is not a State Significant Development, you need development consent from council.

A cogeneration plant with 30 MW or more of generating capacity is known as 'Designated Development' and a development application with an EIS must be submitted to council. For smaller cogeneration projects, contact the council for its development application requirements.

Environmental Impact Statements

Where an EIS is needed you must first obtain project-specific environmental assessment requirements from the Department of Planning and Infrastructure (i.e. Director-General's Requirements).

Step two – Environmental Protection Licence

A cogeneration installation may also be a 'Scheduled Activity', which requires an Environmental Protection Licence from the Environmental Protection Agency (EPA). The thresholds for Scheduled Activities are:

- capacity to generate more than 30 MW of electrical power, or
- metropolitan electricity works (gas turbines) with capacity to burn more than 20 MJ of fuel per second, or
- metropolitan electricity works (internal combustion engines) with capacity to burn more than 3 MJ of fuel per second.

8.2 Air emissions

Cogeneration plants release local emissions from the combustion of fuel in the generator. They therefore must ensure that they adhere to all relevant air emissions regulations.

The interim NO_x policy for cogeneration in Sydney and the Illawarra

This policy sets out how NSW deals with emissions from cogeneration and trigeneration proposals in Sydney and the Illawarra. Cogeneration proposals in these areas should be either NO_x neutral or required to achieve best available technique (BAT) emission performance.

This more stringent requirement is necessary, as air quality in Sydney and the Illawarra currently exceeds the National Environment Protection Measure for Ambient Air Quality. Best available technique for any natural gas-fired stationary reciprocating internal combustion engine in Sydney and the Illawarra, with a capacity to burn less than 7 MJ of fuel per second, (2.7 MW system) has been defined by EPA as 250 mg/m^3. For natural gas-fired stationary reciprocating internal combustion engines with a capacity greater than or equal to 7 MJ of fuel per second, BAT will be determined on a case-by-case basis. EPA should be contacted for the specific requirements for natural gas-fired stationary reciprocating internal combustion engines with a capacity greater than or equal to 7 MJ of fuel per second.

Selective catalytic reduction (SCR) equipment can be fitted to plant to reduce NO_x emissions to comply with this the policy. However, this will increase the capital and maintenance cost of the project.

The Protection of the Environment Operations (Clean Air) Regulation 2010 (CAR)

The Protection of the Environment Operations (Clean Air) Regulation (CAR) prescribes the maximum allowable emissions for an industrial source located anywhere in NSW. The CAR limits reflect the levels achievable using reasonably available technology and good environment practices. The NO_x emission limits for common cogeneration technologies are outlined in Table 16.

Table 16: Protection of the Environment Operations (Clean Air) Regulation 2010 (CAR) NO_x emissions limit

Prime mover	CAR NOx emission limit
Stationary reciprocating internal combustion engine	450 mg/m^3
Gas turbine, used in connection with an electricity generating system with a capacity of less than 10 MW	70 mg/m^3
Any turbine operating on a fuel other than gas, used in connection with an electricity generating system with a capacity of less than 10 MW	90 mg/m^3

Approved Methods for the Modelling and Assessment of Air Pollutants in New South Wales (December 2006)

Proposals for cogeneration must use approved methods for modelling and assessment to demonstrate no adverse impact on human health or the environment. Site-specific factors dictate the level of emission control required. Depending on the sensitivity of the local receiving environment, an item of plant may need to meet emission standards tighter than those in Best Available Techniques (BAT). Contact EPA for detailed requirements for an air quality impact assessment.

Local government

Local governments also specify requirements for cogeneration plant. It is recommended that the relevant council or shire be contacted to obtain the information necessary to submit a development application for any cogeneration proposal.

8.3 Electrical connection

This section considers the regulatory aspects of connection to the grid. Further detail can be found in section 5.

Cogeneration is defined as an embedded generator by the National Electricity Rules (NER).

The application and connection of a proposed cogeneration installation will depend on the capacity (class) of the proposed generator, requirements applied by the relevant DNSP and procedures defined in Chapter 5 (Network Connection) of the NER.

Medium-sized cogeneration plants between 1 MW and 5 MW and generally connected to ≥ 11 kV networks are subject to the NER network security procedures stipulated in Chapter 4 (Power System Security) of the NER. Plants smaller than 1 MW and generally connected to the low-voltage network are required to adhere to the security requirements of the individual DNSP.

The NER sets out a process for the connection of all generators to the network. This process includes:

- a connection enquiry and resultant application to the DNSP:
  - satisfaction of technical and information requirements; the DNSP must be advised on the location of installation, capacity, type, nominal capacity, agreed generated performance standards, required and agreed network services, the period of effect and any factors specific to the connection
  - consultation with other network service providers, including transmission businesses, where the connection is over a particular size
- an offer to connect
- a connection agreement

- eventual testing and tenderisation of the site.

These steps are subject to time limitations binding the network service provider, where the cogeneration proponent provides all reasonable information required to connect to the site.

Contact your local DNSP for further details regarding connection regulations.

Chapter 5 and Chapter 5a of the *National Electricity Rules* (NER)

There has been much discussion of the current connection regulatory requirements for small- to mid-scale cogeneration. The following quote and Table 17 is a direct extract from AEMC's Consultation Paper, National Electricity Amendment (Connecting embedded generators) Rule 2012 (14 June 2012):

> *Chapter 5 of the NER sets out, among other things, the procedure and requirements for connecting to the transmission and distribution networks. Chapter 5a of the NER, which is to be introduced as a part of the national energy customer framework, has been developed to provide for more standardised connection processes for some types of embedded generators.*

The provisions of Chapter 5 compared with Chapter 5a are set out in Table 17.

Table 17: Provisions under Chapter 5 and Chapter 5a of the NER

Type of installation	Registration requirements	Chapter 5 (connection process and technical requirements)	Chapter 5a
Less than 5 MW	Exempt from registration	Chapter 5 provisions do not automatically apply. However, any person can require the network service provider to comply with Chapter 5 and/or elect to use the connection process. Otherwise, jurisdictional processes apply. (Once Chapter 5a has been implemented, a connection applicant can choose between Chapter 5 and Chapter 5a). Jurisdictional technical standards apply.	Chapter 5a applies. Under Chapter 5a distributors must develop 'model standing offers' to apply for 'micro embedded generators', which are typically installations up to 10 kW.
5 MW to 30 MW	Can apply to AEMO for exemption to register as a market participant	If exempt from registration, same provisions as above. (Once Chapter 5a has been implemented, a connection applicant that is exempt from registration can choose between Chapter 5 and Chapter 5a). Chapter 5 provisions apply if registered as a market participant.	Chapter 5a could apply for non-registered embedded generators.
More than 30 MW	Must register as a market participant	Chapter 5 applies.	Chapter 5a does not apply

Potential changes to Chapter 5 and Chapter 5a

After a recent request for a rule change and a subsequent consultation process, on 18 October 2012, the AEMC extended the period of time in which it must make the draft rule determination on the connecting embedded generators rule change request until the end of late 2013.

For further information please visit **www.aemc.gov.au/**

Please refer to Appendix 5 for further details on the regulations and approval requirements.

9 Civil and structural considerations

There are a number of considerations that must be taken into account when determining the location for a cogeneration plant, including:

- space requirements, including maintenance access
- access to allow plant removal for major overhaul
- electrical cable routing from cogeneration generator to electrical points of connection
- hot water or steam pipe routing from cogeneration to thermal point of connection.

If internal, provision of:

- sufficient ventilation air to cool plant. Cogeneration plant emits a significant amount of heat and if the plant room temperature gets to high the plant will not operate as efficiently, in addition there may be electrics only be rated up to 35°C.
- inlet air (combustion air) – particularly for gas turbines
- exhaust ducting
- connection to a cooling tower.

If within a building, the building must have sufficient structural strength to support the cogeneration unit's mass without transmitting undue vibrations.

If installing a trigeneration system on a roof, additional structural support may be required for the absorption chiller.

The dimensions of various cogeneration units are given in Appendix 3.

Noise levels

Cogeneration units produce a significant amount of noise during operation. Almost all the prime movers require sound enclosures (barring some fuels cells and micro turbines). The actual sound levels vary depending or the prime mover, the manufacturer and model. In the case of reciprocating engines, they would normally be in excess of 95 decibels without an enclosure. With a properly designed enclosure, the noise level outside can be completely safe and minimal.

10 Operation and maintenance

It is important to identify all operating and maintenance costs of a running a cogeneration plant to ensure the project is viable.

Depending on the ownership model chosen, the maintenance and operating cost may be between 0.1 and 5 cents per kilowatt hour. This includes labour and standard replacement parts.

Indicative maintenance costs for various cogeneration technologies are shown in Table 18. There are many factors that influence maintenance costs and these should be viewed as indicative only.

Table 18: Indicative maintenance costs ($/kWh) for cogeneration technologies

Technology	Maintenance, $ AUD/kWhe produced	Comments
Gas fired reciprocating engine	$0.018–$0.05	Often the highest maintenance cost among prime movers. Availability typically 85%
Gas turbine (> 1 MW)	$0.01–$0.015	Very reliable, availability > 95%
Microturbine (< 1 MW gas turbine)	$0.01–$0.025	Very reliable, availability > 95%
Steam turbine without boiler plant (> 1 MW)	$0.005–$0.015	Very reliable, availability > 95%
Steam turbine with boiler plant (> 1 MW)	$0.01–$0.02	Very reliable, availability > 95%
Micro steam turbine without boiler plant (< 1 MW)	$0.005–$0.025	Very reliable, availability > 95%
Organic Rankine cycle	$0.005–$0.015	Very reliable, availability > 95%

It is important to identify all operating and maintenance costs of a cogeneration plant to ensure the project is viable.

Depending on the ownership model chosen, the maintenance and operating cost may be between 0.1 and 5 cents per kilowatt hour per year. This should include labour and standard replacement parts.

10.1 Operating requirements

The operating requirements of a cogeneration plant depend on the plant size and technologies.

Cogeneration plants require regular routine inspections that would normally be performed by existing operating staff. Training of operating staff is typically provided as part of the contract to supply the cogeneration plant. In some finance schemes, the operation and maintenance is the responsibility of the solution provider, avoiding the training of existing staff.

Cogeneration plants with reciprocating engines, microturbines or fuel cells can be configured to operate unattended. Cogeneration plants with gas turbines and a heat-recovery steam generator (HRSG) may require additional staffing as dictated by Australian standards. A HRSG of less than 10 MW steam output (or gas turbine with less than 6–7 MWe output) may run unattended, but require supervision by an appropriately trained person with checks at a maximum of 24 hour intervals. A HRSG between 10 MW and 20 MW steam output (or gas turbine 6–15 MWe output) is classified as limited attendance, which requires supervision by an accredited boiler attendant with checks at a maximum of four-hour intervals.

10.2 Maintenance requirements

Most cogeneration plants contain mechanical rotating equipment which requires periodic routine maintenance. Scheduled maintenance and breakdown maintenance are typically undertaken by the equipment manufacturer or their Australian agent.

A maintenance contract is normally agreed with the extent and scope of services tailored to suit the cogeneration plant owner. The maintenance contract may also include guarantees on:

- performance (electrical output, heat rate, thermal output)
- plant availability
- breakdown response time.

Typically for cogeneration plants of the capacity considered by this guide, only consumables (chemicals, lubricants, and filter elements) and minor spares are held on site. The majority of spare parts are held by the equipment manufacturer or maintenance contractor.

The following sections outline the typical maintenance required for common cogeneration equipment. Further details including estimated maintenance schedules can be found in Appendix 4.

Reciprocating engines

Reciprocating engines have many moving parts and contact surfaces and typically have higher maintenance requirements (and costs) than other technologies. Scheduled maintenance is typically performed at 2000 operating hour intervals with major services at approximately 12,000 operating hour intervals. A minor overhaul is typically required at 24,000 to 30,000 hours of operation with a major overhaul required at about 60,000 operating hours (i.e. after about seven years' full-time operation), when the engine is commonly replaced with a reconditioned unit.

Maintenance time can vary from several hours for a minor service to up to a week or more for an overhaul and must be scheduled around operational requirements.

Gas turbines

Gas turbines have limited moving parts so require less maintenance. Scheduled maintenance is typically performed at 2000 operating hour intervals with a major overhaul typically required at 30,000 hours of operation.

Microturbines

Similar to gas turbines, microturbines have limited moving parts and require limited maintenance. Scheduled maintenance is typically performed at 4000 operating hour intervals with a major overhaul typically required at 40,000 hours of operation.

Steam turbines and organic Rankine cycle (ORC)

Steam turbines (and ORC), like gas turbines have limited moving parts but unlike gas turbines have no air intake and therefore no air intake filters to be replaced. They therefore require less time and money to maintain, and are probably the prime movers with the lowest maintenance.

Fuel cells

Fuel cells have minimal moving parts and thus require limited maintenance. The majority of maintenance is for the balance of plant systems such as air-cooled radiators, cooling water pumps and heat exchangers. The fuel cell stack itself has a typical life of 20 years and usually requires major overhaul after 10 years, which involves the replacement of major fuel cell components.

If operating the prime mover only during peak/shoulder time with scheduled off-peak maintenance, a plant can achieve 97.5 per cent availability during prime mover peak/shoulder time.

Absorption chillers

Absorption chillers have minimal moving parts and thus require limited maintenance. Periodic maintenance is typically required to check for fouling and leaks; inspect pumps and test refrigerant solution, seals, gaskets, belts and valves; and refrigerant replaced as required.

Note: if operating the prime mover only during peak/shoulder time with scheduled off-peak maintenance, a plant can achieve 97.5 per cent availability during prime mover peak/shoulder time.

11 Financing and funding

11.1 Finance models

The financial arrangements for a cogeneration project and the delivery model for the project are often inter-related. The following five different delivery and financing models are discussed below:

- engineer, procure, construct, manage (EPCM)
- engineer, procure, construct (EPC)
- build, own, operate (BOO)
- build, own, operate, transfer (BOOT)
- energy performance contract.

Engineer, procure, construct, manage (EPCM)

In this model, the owner (or the owner's consultant) designs the cogeneration and issues separate supply-only or supply and install requests for tender from equipment suppliers for the various elements of the plant.

The owner is responsible for ensuring that the various elements work and perform together appropriately.

In the cogeneration context, a typical package breakdown might be:

- generation set, usually with the heat recovery equipment but sometimes separate
- civil and building works
- mechanical installation and balance-of-plant
- electrical works.

EPCs are often selected over EPCMs because of the relative cost certainty provided by a single contractor with responsibility for turnkey delivery, even though this certainty costs more. The EPCM approach may benefit a project by achieving lower cost and implementation flexibility through managing a small number of specialist contractors rather than engaging a single contractor.

EPCM contracting does involve a greater risk and effort for the owner, due to the management of a greater number of contracts. Generally the extent to which works are broken up in an EPCM arrangement is a balance between cost saving and the ability of the owner to manage risk.

Engineer, procure, construct (EPC)

In the EPC model, the obligation to design and build the plant is transferred to the contractor. It is also called a 'turnkey' contract. The owner specifies the overall performance required and the operating environment/envelope.

This is most often executed as a single contract package, although some components such as the utility connections may be implemented separately.

The owner should choose a contractor who is experienced in the design and construction of cogeneration plants. The contractor must be able to select appropriate plant items and take responsibility for integrating them and commissioning the overall plant. The turnkey contractor is commonly the original equipment manufacturer (OEM) for the primary generation equipment, particularly for smaller projects. For larger projects, a major industrial construction company would commonly participate and draw together key equipment suppliers and designers to work under their overarching project and construction management supervision.

In this model, the project construction and performance risk is transferred to the contractor, which is reflected in the turnkey cost being higher than most other financing models. The owner retains the ongoing operations and performance risks and the market risks (energy tariffs) over the project's life.

Note that in both the EPCM and EPC models, it is also common for the owner to enter into a Long-Term Service Agreement (LTSA, see Appendix 4) with the OEM for the maintenance and service of the major generation plant. The LTSA terms vary, with terms of 4 to 12 years being common depending on the nature of the equipment (e.g. engines versus gas turbines); whether the equipment is using the very latest technology (for which the commercial track record is less established); and whether the OEM is likely to have a monopoly over the service elements for that equipment.

Build, own, operate (BOO)

In the BOO model the contractor (service provider) takes full responsibility for selecting and designing the plant, gaining approvals/consents, financing construction and operation, construction of the plant, ongoing operational and performance risks and market risks (energy tariffs).

The procurement arrangement is based on the owner's output requirements, or key performance indicators (KPIs), such as electricity and heat off-take quantities, qualities and reliability, over the term of the agreement instead of specifying plant sizes and heat rate characteristics. The contractor is generally paid on the basis of fixed and variable charges (tariffs) on the electricity and heat used by the facility. If the contractor fails to meet the agreed KPIs in any period through the term of the agreement, then offsets are typically applied to the fees payable to the contractor.

The facility must generally commit to taking a minimum amount of energy from the contractor (called a take-or-pay provision) or else is provided with strong incentives to do so, in the form of fixed and variable tariffs.

The term of the BOO agreement needs to be long enough so that the contractor can amortise the capital costs and set-up costs in a reasonable fashion into the fees and tariffs. Unless there is a strong resale market for the equipment (not generally the case for cogeneration plants), the term of the BOO agreement tends to be a reasonable percentage of the technical life of the equipment and plant. Twelve to 25 years would be typical, with terms seldom below ten years.

As the relationship between the parties endures for such a long period, and the matters to be agreed and measured are complex, the BOO agreements are very commonly bespoke agreements, with external legal and (often) financial advisors.

The transaction costs for BOO projects, especially where they are project financed, tend to be large because of the level of negotiation and complexity of agreements required and the due-diligence processes adopted. Consequently, project finance is rare for projects under approximately $50 million in capital cost.

This model is not generally used for the relatively small projects that are the focus of this guide.

Build, own, operate, transfer (BOOT)

The BOOT model is a variation of the BOO model where at the end of the agreement the plant ownership (and operating obligations) are transferred to the facility owner.

Sometimes a payment is made for the assets (particularly if the BOO term is relatively short compared to the plant's life). Sometimes the transfer is not automatic but depends on the exercising of an option.

Energy performance contract

Energy performance contracting is a delivery model in which a developer contracts to deliver an energy performance outcome (such as reducing electricity consumption by an agreed amount at the site) and is paid according to the agreed measure when the performance outcome has been established.

Typically the contract does not include market risk. For example, the cost saving gained by the measure is often calculated using the energy tariffs prevailing at the time of the agreement, rather than those that actually apply over the project's life.

Cogeneration projects may be suitable for energy performance contracts.

Agreements tend to be bespoke and hence more complex than conventional procurement or EPC models, but tend not to be long-lived and hence are of lower complexity than BOO-type models.

11.2 Grants and funding options

Funding opportunities exist for technologies and initiatives related to greenhouse gas emission reduction, climate change adaptation and/or other clean energy and renewable energy initiatives. Below is an overview of some of the funding programs currently available. Refer to the relevant website for closing dates and further information on these programs.

NSW Government

NSW Office of Environment Energy Saver program

This program supports energy efficiency for medium to large organisations. The program provides energy efficiency knowledge and training resources including sector technology guides along with assistance in business case development and identifying energy saving opportunities. Assistance includes cogeneration pre-feasibility studies.

To check eligibility to access this program please contact the energy saver team on 1300 361 967 or email energysaver@environment.nsw.gov.au.

NSW Environmental Upgrade Agreements (EUA)

Environmental Upgrade Agreements (EUAs) make it easier to access finance for environmental improvements to existing commercial, industrial, strata scheme and large multi-unit residential buildings in NSW (Figure 25).

Under this agreement, a finance provider lends funds to a building owner for water, energy and other environmental upgrades, and this low-risk loan is repaid through a local council charge on the land.

Tenants of commercial buildings can be asked to contribute to the loan costs; such costs are offset by the same amount of saving generated by reduced energy and water bills.

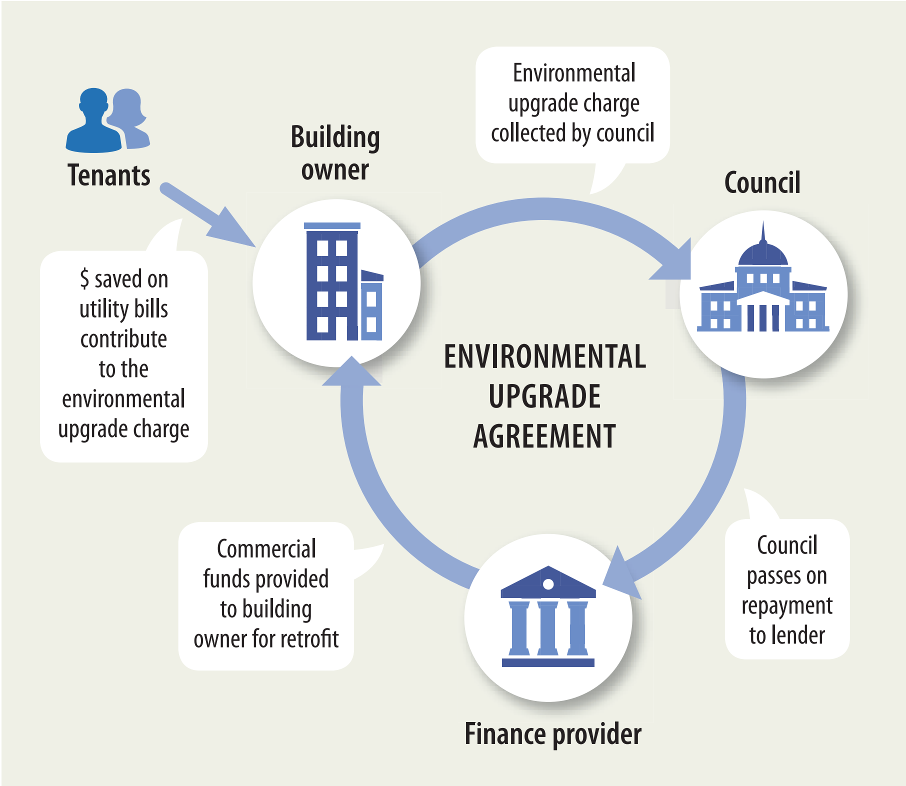


Figure 25: Environmental Upgrade Agreement framework

- The building owner, council and finance provider voluntarily enter into an EUA.
- The building owner agrees to carry out the environmental upgrade works.
- The finance provider agrees to advance the funds for the works.
- Council agrees to level environmental upgrade charges to pass repayments on to the finance provider (minus council's processing fees).

For more information on Environmental Upgrade Agreements email **energysaver@environment.nsw.gov.au** or phone 1300 361 967.

Sustainable Government

Funding for energy and water efficiency upgrade projects is available to NSW general government agencies in the form of a repayable capital advance.

Application for funding is managed by the NSW Office of Environment and Heritage (OEH), whose specialist team also provide support and advice to help identify, develop and implement suitable efficiency upgrade projects.

To be eligible for funding projects must:

- reduce a facility's energy or water consumption without reducing output
- demonstrate an IRR of 12 per cent or higher, with 75 per cent of the projects gross benefits directly related to energy and/or water savings
- satisfy OEH's verification processes.

For further details please contact the OEH Sustainable Government team on 1300 361 967 or email **government@environment.nsw.gov.au**

The NSW Energy Savings Scheme (ESS)

This scheme provides financial incentives to use grid electricity more efficiently. The recent changes to the NSW Energy Saving Scheme in June 2014 state that any savings that result from the generation of electricity are ineligible, therefore cogeneration and trigeneration projects would not be eligible for Energy Saving certificates. The relevant excerpt is in Clause 5.4 (f)

5.4 Recognised Energy Saving Activities do not include any of the following:

(f) an activity that reduces electricity consumption by generating electricity from any source or by converting non-renewable energy to provide equivalent goods or services;

The eligibility of any project is determined according to the ESS rules by the scheme administrator, the Independent Pricing and Regulatory Tribunal (IPART).

For more information see **www.ess.nsw.gov.au**

12 Measurement and verification

Measurement and verification are important parts of any energy efficiency project including cogeneration projects. The metering of fuel use and electrical and thermal output are important to provide robust verification of the cogeneration plant's performance and efficiency.

Often, the only means of metering the consumption of electricity or gas at a facility is by using the supply meters used for billing. Although useful, this approach is limited since it does not show where the energy is being used within the facility and typically makes efficient management of energy equipment impossible.

An example measurement and verification flow chart that can be followed to ensure good planning and execution of measurement and verification principles in provided in Figure 27.

A measurement and verification plan should be developed as part of the cogeneration project to ensure that targeted energy savings are achieved in practice.

Key issues

Energy consumption over a suitable baseline period should be gathered. Data for a baseline period of 12 months or longer (or since the last major energy efficiency project) should be considered for comparing with the cogeneration system's performance.

A boundary must be established for the measurement of energy and improvement in efficiency at the facility (both electrical and thermal). Unless sufficient energy sub-metering equipment is installed, the measurement boundaries would be the total energy used by the site.

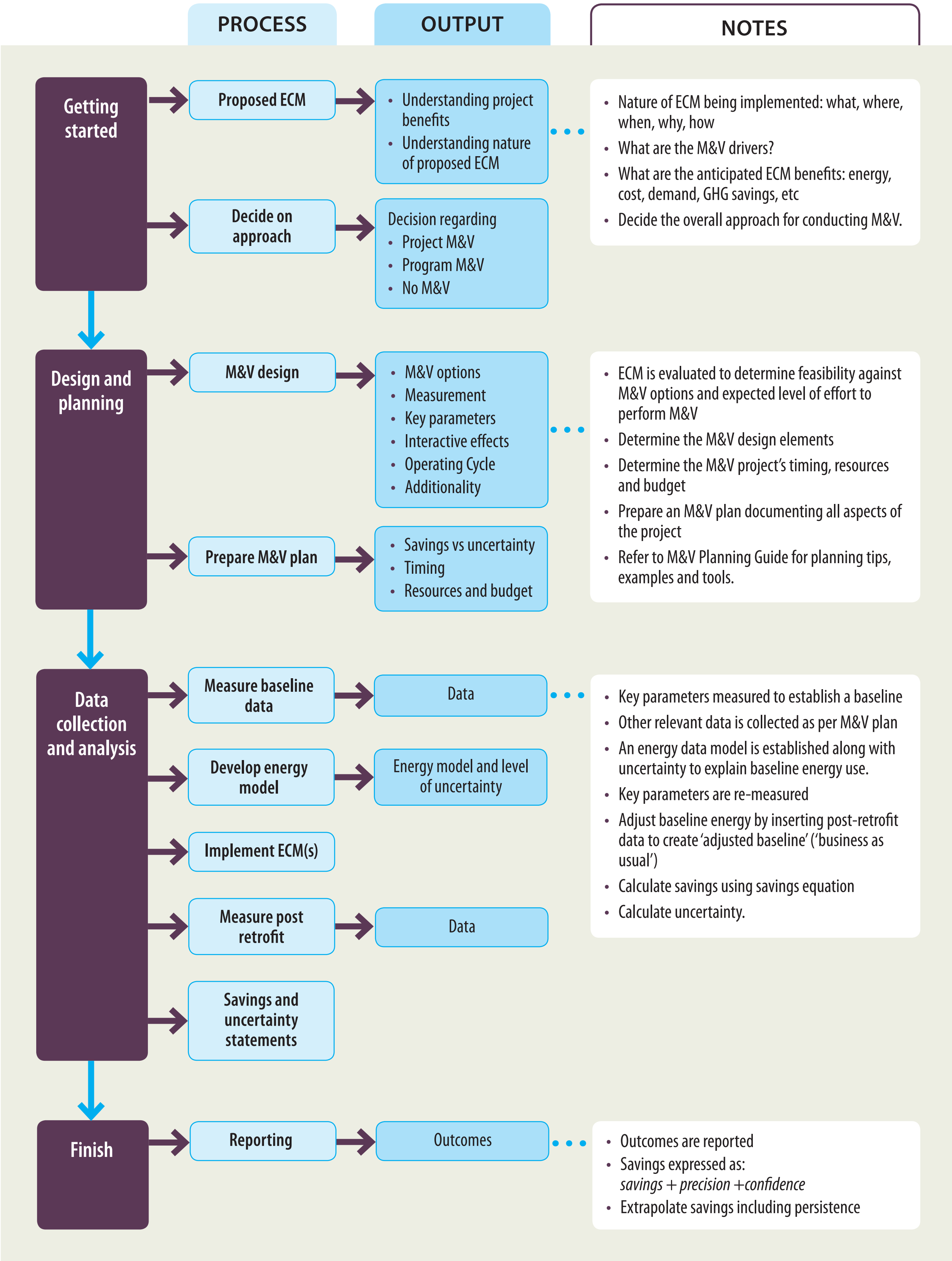
Temporary sub-metering can be installed to assist with the verification of reductions in energy use. This is normally easier for the measurement of electrical energy.

Where the energy consumption of a facility is significantly influenced by production rate, ambient temperature or other factors, regression analysis of the baseline energy data along with the relevant data should be considered. This regression would then be used to estimate the facility's energy consumption after the cogeneration project is implemented and evaluate the efficiency improvements.

If a number of energy efficiency projects are being implemented within a similar period, the total improvement in efficiency will need to be measured (unless there is sufficient energy sub-metering available to verify the efficiency gains in each of the areas involved).

For further information on appropriate measurement and verification processes and protocols, including a step-by-step guide, refer to OEH's Measurement and Verification Operational Guide: www.environment.nsw.gov.au/resources/climatechange/120992reandcogenapp.pdf

Figure 26: Measurement and verification of a cogeneration project



13 Cogeneration examples

Facilities most likely to benefit from cogeneration are those that have simultaneous large electrical and thermal loads (hot water, heat, steam or chilling). Examples are hospitals; food and beverage processors; chemical and plastic producers; pulp, paper and fibreboard manufacturers; metals processors; textile producers; data centres; and manufactures with large thermal processes.

Other sectors that may be viable with careful consideration include hotels, shopping centres; universities and TAFEs, large commercial buildings and aquatic centres. However, alternatives to cogeneration may provide better outcomes.

This section provides qualitative examples of cogeneration facilities in different applications with some generic benefits and risks. Weekly and annual load curves are provided with and without cogeneration installed. The applications highlighted in this section are:

- manufacturing
- data centre
- hotel
- office building
- aquatic centre.

Each application is assumed to make a saving during off-peak periods. All cogeneration units used are assumed to be at 100 per cent load factor and 100 per cent thermal utilisation while operating. This may be difficult to achieve in practice. A summary can be found in Table 19.

Table 19: Summary of cogeneration benefits and risks for common sectors

Sector	Benefits	Risks
Manufacturing	• High probability of stable and coincidental electrical and thermal loads • High cost savings • GHG emission reductions • Cheaper energy source • Partial electrical load security • Potential peak demand savings	• Regulatory and environmental approvals • Increased maintenance costs • Poorly designed systems can lead to power outages and reliability issues • Existing thermal utilities may run outside of ideal cogeneration operating ranges
Data centre	• High probability of stable and coincidental electrical and thermal loads • Reduction in carbon footprint • Less susceptible to grid electricity price fluctuations • increased reliability and redundancy	• Potential complex connection to integrate with the uninterrupted power supply (UPS) system • Regulatory and environmental approvals
Hotel	• Reduction in carbon footprint • Cheaper energy source • Partial electrical load security • Potential peak demand savings	• Hotels without laundries are unlikely to have significant thermal demand to justify cogeneration • Greater potential for load variations make sizing difficult and harder to justify • Regulatory and environmental approvals • Increased maintenance costs • Poorly designed systems can lead to power outages and reliability issues

Sector	Benefits	Risks
Commercial Office	• GHG emission reductions • Cheaper energy source • Partial electrical load security • Potential peak demand savings • Increased asset value • Improved environmental ratings	• Unlikely to have over 3300 hours of co-incidental thermal and electrical loads generally needed to optimise the system • Regulatory and environmental approvals • Likely to require HVAC equipment to operate at partial loads during operation of trigeneration therefore reducing returns • Potential complex installation due to space constraints and existing equipment. Potential for significant site downtime. • Increased maintenance costs • Liability clauses on leases for system outages • Lease lengths and terms • Integration of absorption chiller into existing systems can be difficult • Cheaper and more efficient upgrades may be available (i.e. high efficient electric chillers)
Aquatic centres	• GHG emission reductions • Cheaper energy source • Partial electrical load security • Potential peak demand savings • High thermal loads	• Relatively high cost per kw capacity due to relatively low electrical consumption • Cheaper and more efficient upgrades may be available (i.e. VSD, solar thermal) • Regulatory and environmental approvals • Increased maintenance costs

13.1 Manufacturing plant

Base conditions:

- the plant produces ice cream
- it operates for 24 hours per day, seven days a week
- electricity is used on site to run processes, refrigerators, chillers, HVAC and other equipment
- gas is used solely to fire a steam boiler and around 50 per cent of the steam is used to make hot water for process cleaning.

Plant selected:

600 kWe gas reciprocating engine

Electricity and gas load profiles

Figure 27 shows a typical weekly electricity and gas consumption load profile for the ice cream facility.

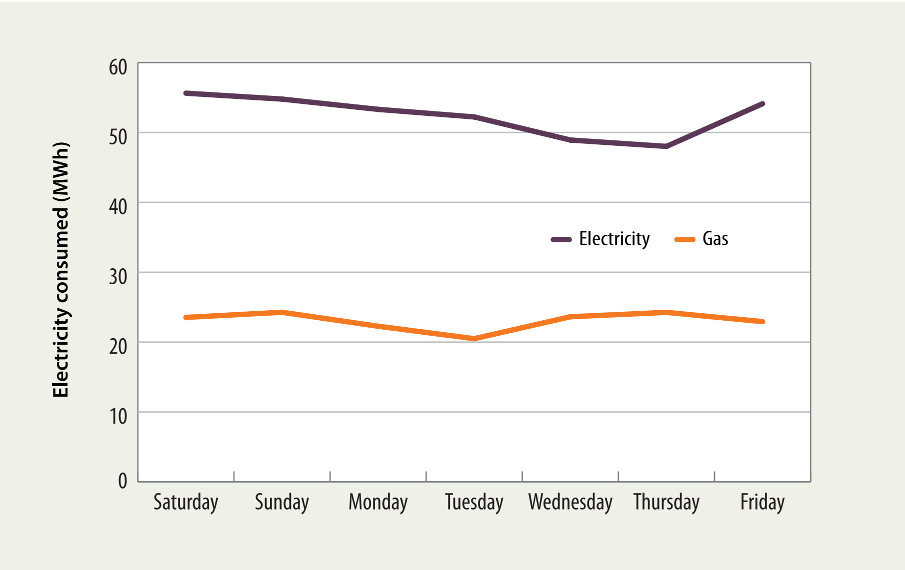
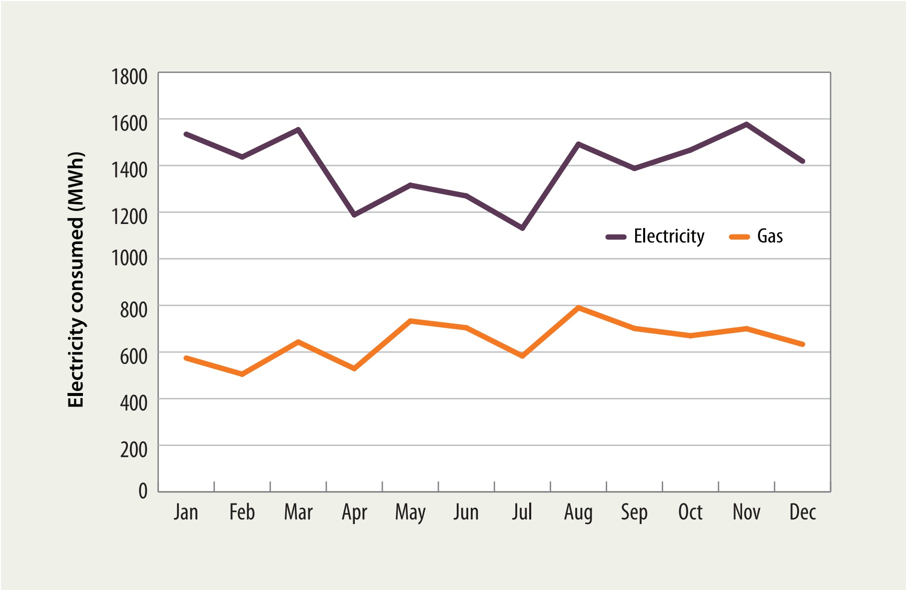


Figure 27: Weekly electricity and gas consumption for a manufacturing plant

Electricity contributes more than twice as much energy as gas, because of the large refrigeration load for processing and storage (Figure 27). The site has a fairly constant load profile over a typical day and week.

Monthly electricity consumption follows a seasonal trend, with consumption lower in winter (Figure 28). This is to be expected, as the warmer summer months are the peak season for ice cream production. Gas consumption is not so variable, but shows a slight increase towards the end of winter.

Figure 28: Yearly electricity and gas consumption for a manufacturing plant

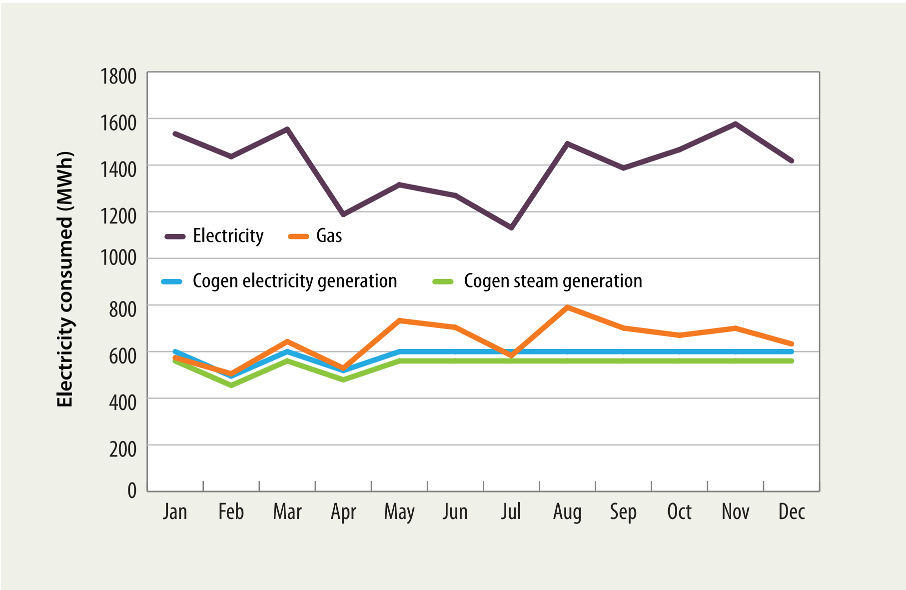


The relatively constant load profile and the simultaneous need for electrical and thermal energy makes this application a good candidate for cogeneration.

Installation of a cogeneration facility

The monthly loads for the same manufacturing plant, with a reciprocating engine cogeneration unit installed, are shown in Figure 29. The figure shows the total demands, and the impact of cogeneration on gas and electricity profiles. The new demand for power from the grid is the difference between the two electricity lines.

Figure 29: Yearly electricity and gas consumption with cogeneration at a manufacturing plant



The cogeneration heat generation line shows the amount of steam produced by the cogeneration unit during the year (Figure 29).

The cogeneration unit chosen in the example plot has been sized to run at maximum output for most of the year, with some reduction in capacity during slower periods.

Potential risks and benefits for the installation of a trigeneration facility at the manufacturing plant are as follows.

Risks:

- time and cost to gain regulatory and environmental approvals
- increased maintenance costs
- reliability issues within the engine can drop out the entire site due to synchronous running with the grid
- existing thermal utilities may run outside efficient operating ranges.

Benefits:

- potential high thermal demand
- potential constant and simultaneous demand for thermal and electricity
- GHG emission reductions
- cheaper energy source
- partial electrical load security
- peak demand savings.

13.2 Data centre

Base conditions:

- located in Sydney, NSW
- online 24 hours per day, seven days a week
- current receiving electricity from grid
- backup system is uninterruptable power supply (UPS) in emergencies
- operational requirements of a very high uptime and strict temperature control of servers.

Plant selected:

1200 kWe gas turbine

Electricity and gas load profiles

Data centres are heavy electricity consumers, demanding power consumption for servers, UPS batteries, lighting and HVAC systems. Typically, HVAC accounts for more than a third of the total energy consumed in a data centre.

Electricity consumption follows a seasonal trend, with less electricity required in the cooler months, when ambient temperatures are lower.

Figure 30: Data centre yearly consumption with trigeneration

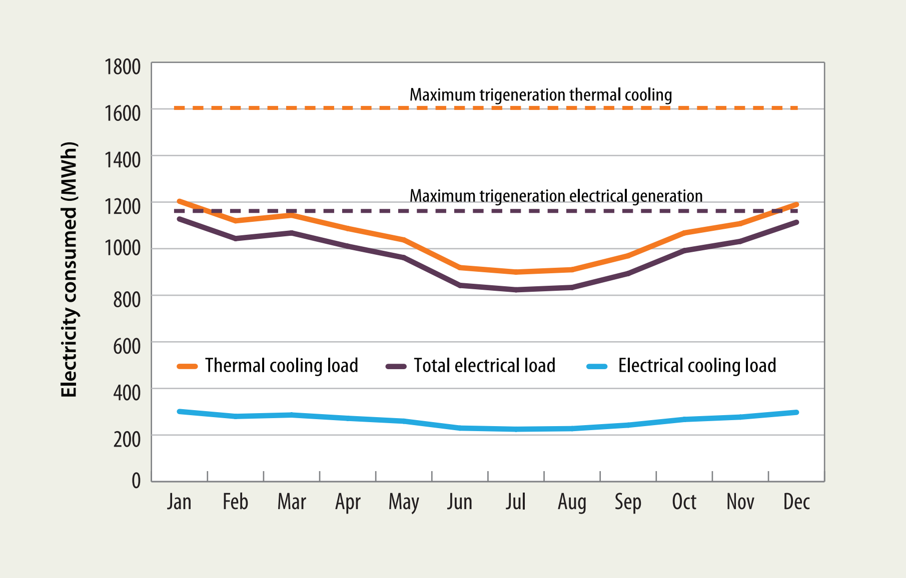


Figure 30 shows the effect of a trigeneration unit on the data centre over a year and assumes an existing cooling system with a COP of 4.

Installation of a trigeneration facility

The constant load profile and the simultaneous need for both electric and thermal power make this application a good candidate for trigeneration. The installation of a trigeneration facility can remove reliance of power supply from the main grid.

The trigeneration facility consists of a gas turbine generator and an absorption chiller plant. The thermal cooling load remains constant as the number of servers demanding cooling has not changed; but the total electrical and electrical cooling loads have been replaced entirely by the electricity and thermal cooling from the trigeneration unit. An over-sized plant has been chosen to show the electricity generated by the unit supplying the total electricity demand (Figure 30). In sizing this way, a significant portion of cooling capacity of the unit is unused but this increases the redundancy of the system and highlights the importance of maintaining the data centre uptime. Using this approach, the unit will run at 100 per cent capacity only when the data centre is at full load.

Potential risks and benefits for the installation of a trigeneration facility at the data centre are as follows.

Risks:

- time and cost to gain regulatory and environmental approvals
- synchronisation with existing UPS and grid.

Benefits:

- reduced greenhouse gas emissions – 100 per cent gas usage
- fluctuations/spikes in power supply from the grid do not have an impact
- high stable and coincidental electrical and thermal loads (cooling)
- increased reliability of a gas turbine for a data centre which requires zero down-time – the benefit of using a gas turbine over a reciprocating engine in this example
- increased redundancy.

A reciprocating engine generator would likely be significantly cheaper than a gas turbine in this case, but would be less reliable.

13.3 Hotel

Base conditions:

- located in the Sydney central business district (CBD)
- gas-fired hot water
- has a laundry on premise
- space heating and cooling are achieved through reverse cycle air conditioners.

Plant selected:

800 kWe gas reciprocation engine.

Electricity and gas load profiles

Factors affecting electricity and gas consumption include occupancy rate, kitchens, laundries, convention rooms and HVAC, and these loads vary seasonally (Figure 31).

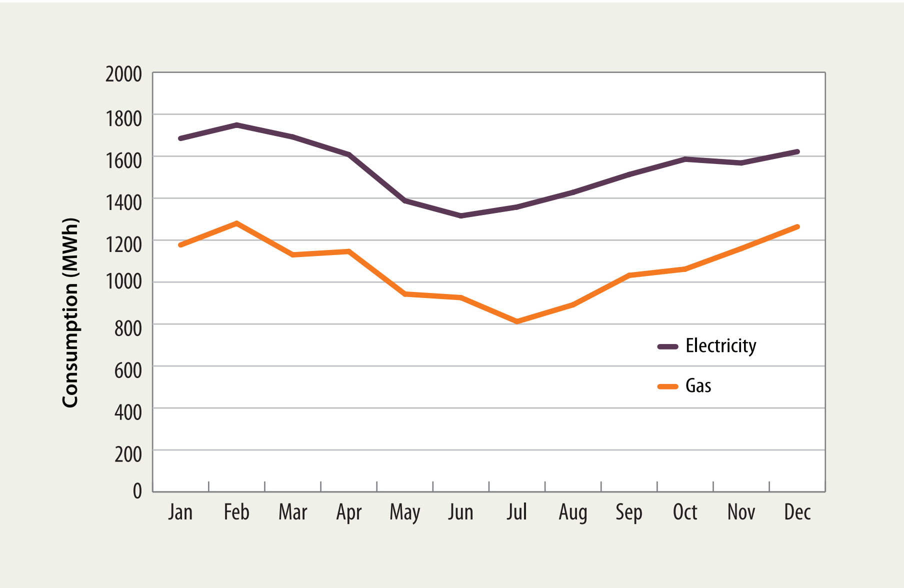


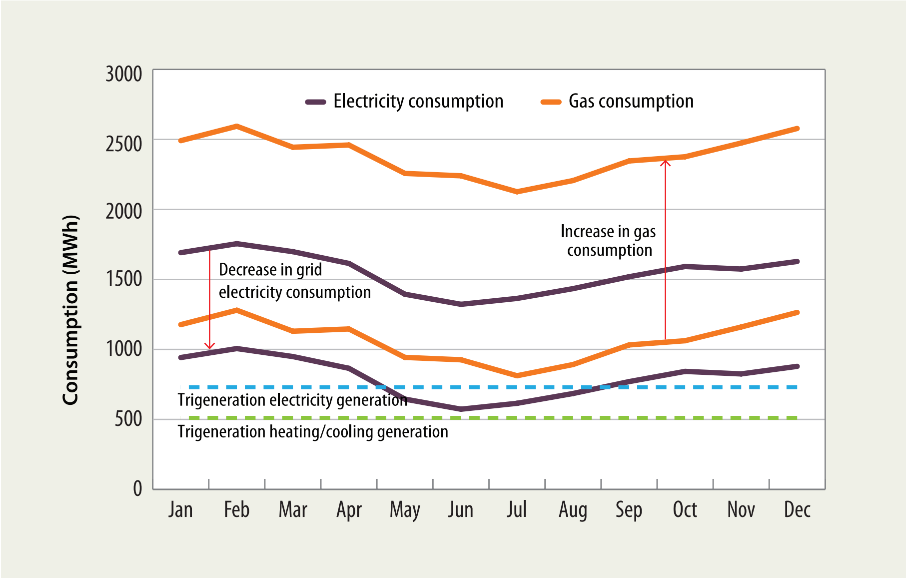
Figure 31: Yearly electricity and gas load profile at a hotel

This variation in load is due to ambient temperatures. During a typical week and day, consumption can also vary significantly, with increased load over the weekend due to higher occupancy on Saturdays and Sundays. It also shows increased load from 5 pm onwards, when guests return to their rooms and turn on air conditioning units and appliances.

Installation of a trigeneration facility

The plant consists of a reciprocating engine generator and an absorption chiller plant. Figure 32 shows the yearly consumption.

Figure 32: Yearly gas and electricity consumption at a hotel with trigeneration



Absorption chillers could replace any electric chillers used and reduce the power consumption. The electrical generation should be adjusted accordingly. For each 100 kW reduction in electric chiller cooling load, a reduction of 20–25 kW of electrical consumption would be expected (depending on the chiller COP).

The hotel's cooling requirements will only occasionally match the availability of waste heat. A separate controllable cooling system should be provided to make up the difference when necessary.

Potential risks and benefits for the installation of a trigeneration facility in the hotel are as follows.

Risks:

- time and cost to gain regulatory and environmental approvals increases in built up areas
- increased maintenance costs
- reliability issues within the engine can black out the entire site due to synchronous running with the grid
- hotels without laundries are unlikely to have sufficient thermal demand to justify cogeneration
- hotels are more likely to have excessive fluctuations in load, making sizing and matching of cogeneration plants more difficult/harder to justify.

Benefits:

- GHG emission reductions
- cheaper energy source
- partial electrical load security
- peak demand savings.

13.4 Office building

Base conditions:

- building is multi-storey and located in a major CBD
- the building is open 24 hours per day, seven days per week
- offices are normally occupied between 8.00 am and 6.00 pm on working days. Occupancy rates are low outside of these hours
- the building includes a restaurant/coffee shop
- electricity uses include lighting, lifts, computers, office equipment, refrigerators
- HVAC is produced with a centralised unit
- hot water is generated by a centralised gas fired unit.

Electricity and gas load profiles

Office buildings generally have constant occupancy rates over a year and consequently lighting, lifts and services loads remain fairly constant over the year. Ambient temperature affects the HVAC load, changing from cooling in summer to heating in winter months. Figure 33 shows a typical yearly electricity and gas consumption load profile for the office building.

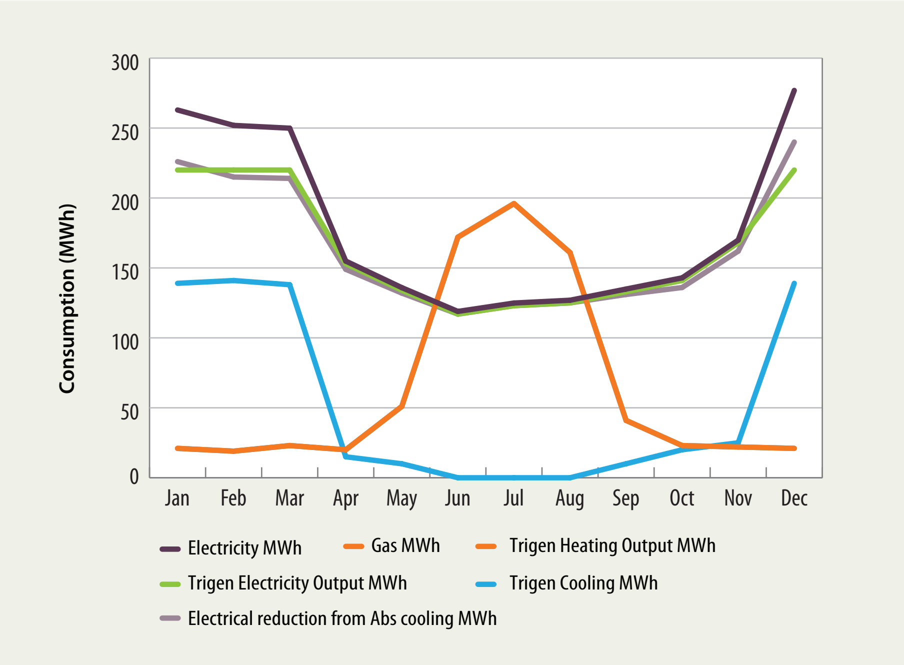


Figure 33: Yearly electricity and gas consumption of an office building

A trigeneration plant using a reciprocating engine and an absorption chiller has been overlaid against the office building's existing electrical and gas usage profile in Figure 33. The plant was sized so its maximum electrical output is no more than 220 MWh per month. Thus, it can run as low as 110 MWh per month and can operate throughout winter when the electrical load is low.

Office buildings are likely to have small steady electrical and gas loads, making sizing and matching of cogeneration plants straightforward.

The building HVAC load occurs predominantly over the summer months from November to March. The relatively short operating hours make it difficult to achieve an effective payback period for trigeneration. Modern electric HVAC chillers have high energy efficiency and are generally lower in cost than the absorption chillers used in trigeneration facilities. These are likely to be a more cost-effective solution.

It should be noted that some commercial buildings have installed cogeneration to increase Green Star or NABERS ratings through fuel switching, while only capturing and using a minimal or zero amount of waste heat. This leads to very inefficient cogeneration systems and is not considered best practice.

Potential risks and benefits for the installation of a trigeneration facility in the office building are as follows.

Risks:

- time and cost to gain regulatory and environmental approvals
- likely to require HVAC equipment to operate at partial loads while trigeneration is running
- increased maintenance costs
- potential complex installation due to space constraints and existing equipment
- potential for significant site downtime during installation
- liability clauses on leases for system outages
- existing lease lengths and terms
- integration of absorption chiller into existing systems can be difficult
- may not be the most effective outcome if you are required to use the waste heat to ensure the cogeneration system is viable
- cheaper and more efficient upgrades may be available (i.e. high efficiency electric chillers).

Benefits:

- GHG emission reductions
- improved NABERS rating
- cheaper energy source
- partial electrical load security
- potential peak demand savings
- potential increased asset value.

13.5 Aquatic centre

Base conditions:

- located in a coastal area with mild winter temperatures
- open 15 hours per day, seven days per week
- pool and hot water heating is by gas
- the centre includes a gymnasium and café.

Electricity and gas load profiles

The aquatic centre uses electricity primarily for lighting and HVAC. Consumption remains fairly constant over the year. Gas consumption is strongly influenced by ambient temperature and increases significantly in the cooler winter months. Figure 34 shows a typical yearly electricity and gas consumption load profile for the aquatic centre.

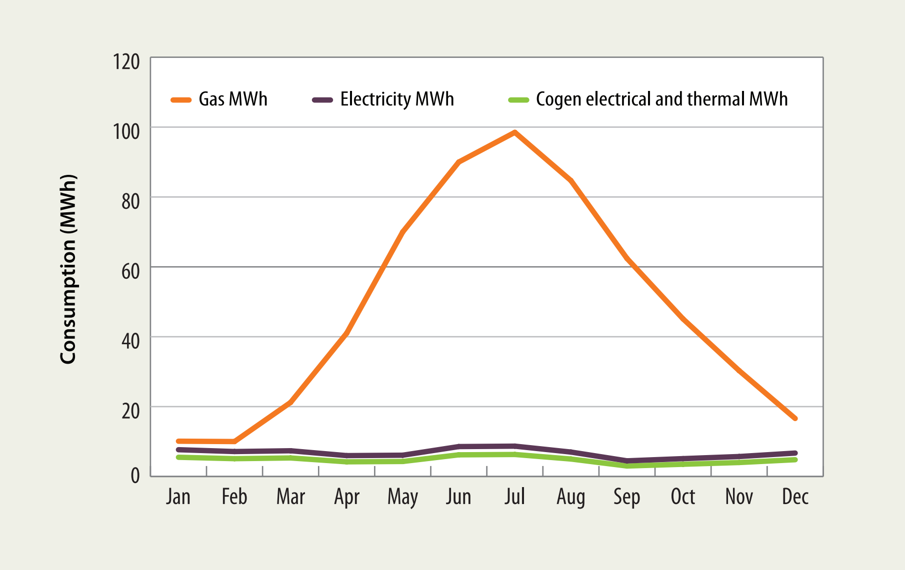


Figure 34: Aquatic centre yearly electricity and gas consumption

Aquatic centres typically have steady electrical loads, making the sizing of a cogeneration plant relatively straightforward. However, the pool heating load is typically significantly higher than the centre's electrical load. Heat recovered from a cogeneration facility could only provide a small portion of the centre's heat load. The cogeneration unit's capacity is therefore small, so costs for the cogeneration facility in dollars per kilowatt would be relatively high.

The small electrical load (less than the 150 kWe guideline given in the viability checklist in section 3.10) means that other technologies such as solar thermal or a heat pump are likely to be better suited to this application (refer to section 3.9 for more information). A suitably sized cogeneration has been provided in comparison for informational purposes (Figure 34). The line shows both the thermal and electrical output of the reciprocating engine system selected (roughly equivalent thermal and electrical generation).

Potential risks and benefits for the installation of a cogeneration facility at the aquatic centre are as follows.

Risks:

- time and cost to gain regulatory and environmental approvals
- relatively high cost per kilowatt capacity due to the relatively low electrical consumption
- increased maintenance costs
- alternative renewable thermal solutions may be more practical.

Benefits:

- GHG emission reductions
- cheaper energy source
- partial electrical load security
- peak demand savings.

14 Next steps

> If your site is in NSW, the OEH may be able to provide assistance with an energy investigation, financial or engineering support or subsidised training. Contact the OEH now or visit **www.environment.nsw.gov.au/business/**

Your initial study using this guide will help you to determine whether:

1. cogeneration or trigeneration will certainly provide good benefits
2. the structure of the facility loads means that cogeneration or trigeneration cannot provide any benefits
3. benefits may be achievable but a more detailed study is required.

If cogeneration or trigeneration cannot provide any benefits (option two) then no further action is needed. In the other instances, you should commission a detailed engineering feasibility study. Here are the typical steps towards a final decision:

- prepare a brief for:
  - a consultant to prepare a detailed feasibility study (see Appendix 6 for an full study outline), or
  - a proposal from an EPC contractor to design and install a system see section 11 for more details
- evaluate the full feasibility study or proposal completed by experienced personnel
- review government funding opportunities and the corresponding application processes
- develop a business case and get approval to implement.

14.1 Business case outline

The ability to develop a good business case is a crucial step to ensuring the project will be implemented.

Most organisations have their own business case or capital expenditure request templates. Table 20 shows the information a cogeneration business case should include at a minimum.

Table 20: Outline of business case

Section	Content	Example
Project overview	Brief statement on the 'what' and 'why' of the project	Installation of a cogeneration project to reduce the site's energy costs
Project goal	Relate the goal of the project to a strategic goal of the organisation	Corporate goal to reduce site's energy costs by 10 per cent
Project description	Detailed information on what the project involves	Size and type of the cogeneration unit, location of the unit, operation and maintenance requirements
Financial analysis	The financial and economic analysis of the project including total project costs and savings over the lifetime of the project	NPV, IRR, payback, fully installed capital costs, scheduled maintenance costs
Key benefits	Outline the key benefits, financial and non-financial and relate back to the organisation's strategy	GHG emission reduction, avoiding electricity price rises, improved corporate image
Key risks	Consideration of both project and organisation wide risks. Sensitivity analysis of key project inputs	OHS, price forecast uncertainty, commissioning issues, sensitivity to price changes
Business impacts	Any other impacts on the organisation operations	Operation downtime when installing equipment, increased maintenance requirements
Timeframe	Expected length of project	From design to commissioning

APPENDICES

Appendix 1: Calculations and spreadsheets

Template calculation spread sheet

NSW OEH has a spread sheet available that can help you to calculate and evaluate the savings. To receive a copy please contact the Energy Saver Team on 02 8837 6000. This spread sheet can be used when following the methodology outlined in section 4 – for a site with a cooling load it is simply graphed the same way as a heating load.

The data centre and hotel examples in section 13 explain the effects on site electrical loads of introducing thermally-driven cooling.

High heating value (HHV) and low heating value (LHV)

When a fuel is burned, some of the energy is released as latent heat in the water vapour produced. Two different methods of reporting heating value can occur depending on whether or not the latent heat in water vapour is included in the heat of combustion for the fuel. The high heating value (HHV) includes the latent heat of condensation of any combustion water vapour, while the low heating value (LHV) does not include this latent heat.

In summary:

- high heating value (HHV) - total energy from combustion process
- low heating value (LHV) - total energy from combustion process less heat of condensation from any water produced.

The efficiency of large power stations is commonly reported on a fuel HHV basis. However, the efficiencies of cogeneration units are sometimes reported on a fuel LHV basis. It is therefore important to check the basis of stated fuel efficiencies.

To convert stated efficiencies from LHV to HHV, the following relationship should be used:

$$\textit{Thermal efficiency}_{\textit{HHV BASIS}} = \textit{Thermal efficiency}_{\textit{LHV BASIS}} \times (LHV/HHV)$$

Thermal data collection and calculation

For hot water loads, the supply temperature; return temperature; and mass flow rate must be measured and logged at regular intervals (say every 10 minutes). The heating load can then be calculated as:

$kWt = Cp \ x \ m \ x \ \Delta T$

$m = r \ x \ Q$

where

Cp = specific heat of water (4.18 kJ/kg per °C)

ρ = density of water (1000 kg/m^3 at 4°C)

m = mass flow, kg/s

Q = volumetric flow, m^3/s

ΔT = supply temperature – return temperature, °C

For steam loads, the steam temperature and pressure, condensate temperature and mass flow rate must be measured and logged at regular intervals (say 10 minutes). The heating load can then be calculated as:

$kWt = m \ x \ \Delta h$

$m = r \ x \ Q$

where

m = mass flow, kg/s

ρ = density of steam, kg/m^3

Q = volumetric flow, m^3/s

Δh = enthalpy change, kJ/kg

The enthalpy change is the difference between the steam enthalpy and condensate enthalpy. The required values can be found in steam tables.

For cooling loads, the supply temperature, return temperature and mass flow rate must be measured and logged at regular intervals (say every 10 minutes). The cooling load can then be calculated as:

$kWr = Cp \ x \ m \ x \ \Delta T$

$m = \rho \ x \ Q$

where

Cp = specific heat of water (4.18 kJ/kg per °C

ρ = density of water (1000 kg/m^3 at 4°C

m = mass flow, kg/s

Q = volumetric flow, m^3/s

ΔT = return temperature – supply temperature, °C

Appendix 2: Technology and equipment overview

Generation plant

The key features of the cogeneration plant technologies covered by this guide are summarised in Table 5 (section 4, page 26).

Reciprocating engines

A reciprocating engine generator incorporates a natural gas-fuelled spark-ignition engine coupled to a synchronous 50 Hz three-phase electric generator mounted on a common base frame. Generators of the size range covered by this guide are high-speed 1500 rpm units from 50 kW to 4000 kW in size. An example is shown in Figure 35 below.

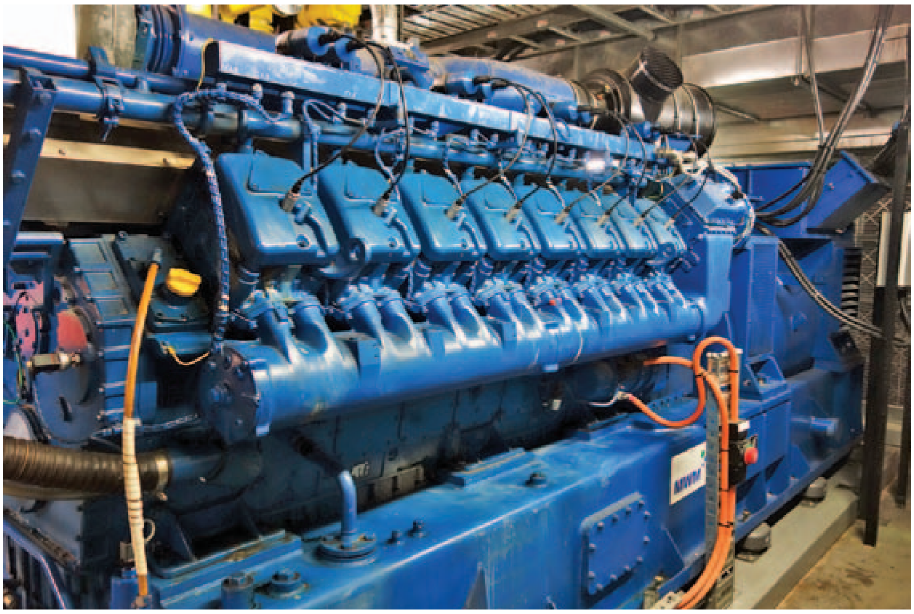
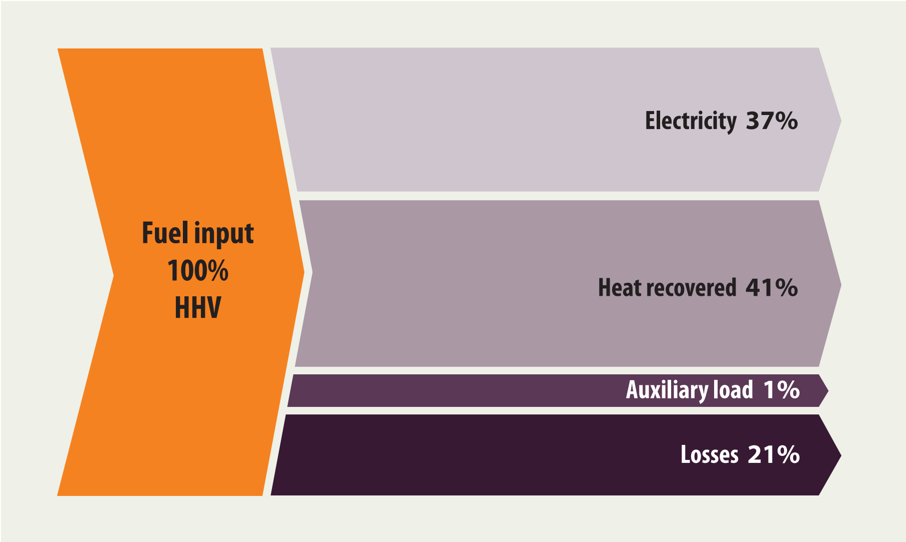


Figure 35: Gas-fired reciprocating engine and generator

Heat can be recovered from the engine cooling system and exhaust. Heat is typically recovered from the cooling system's first stage intercooler, lube oil and jacket water via plate heat exchangers to provide hot water at 80–90°C. The second stage intercooler can only provide low temperature heat at less than 50°C, which is generally not usable for cogeneration and therefore it is cooled by a radiator. The exhaust heat can be recovered via an exhaust gas boiler to provide either hot water at around 90°C or medium-pressure saturated steam at up to 900 kPa at approximately 180°C.

A typical energy balance for a 1 MW reciprocating engine generator in a cogeneration application is shown in Figure 36. Heat is recovered as hot water in the diagram (called a Sankey diagram) with a heat-to-power ratio of 1.1:1. If heat is recovered as steam, the heat-to-power ratio would be approximately 0.5:1 as steam can only be generated from the exhaust heat.

Figure 36: Reciprocating engine generator Sankey diagram



Key performance parameters of a range of reciprocating engine generators are given in Table 21 below. The electrical efficiency of reciprocating engine generators improves with larger units, although the overall cogeneration efficiency remains similar.

Table 21: Typical reciprocating engine generator performance (natural gas)

Parameter	Unit	100 kW	500 kW	1 MW	2 MW
Fuel input (HHV)	[kW]	300	1470	2700	5070
Fuel input (HHV)	[GJ/h]	1.1	5.3	10.4	18.3
Electrical efficiency (HHV)	[%]	33.3	34.0	37.0	39.4
Thermal output[1]	[kWt]	130	630	1100	2000
Thermal efficiency (HHV)	[%]	43.3	42.9	40.7	39.4
Auxiliary load (typical)[2]	[%]	3.0	3.0	3.0	3.0
Cogeneration efficiency (HHV)	[%]	76.6	76.9	77.7	78.8
Heat-to-power ratio		1.3	1.3	1.1	1.0

1. Heat recovered as hot water from lube oil, stage one intercooler, jacket water and exhaust (cooled to 120°C).
2. As a percentage of electrical output.

These units can operate over a load range of 50–100 per cent, but the electrical efficiency reduces at part load (Figure 37). At a load below 50 per cent, the generator cannot run and will shut down.

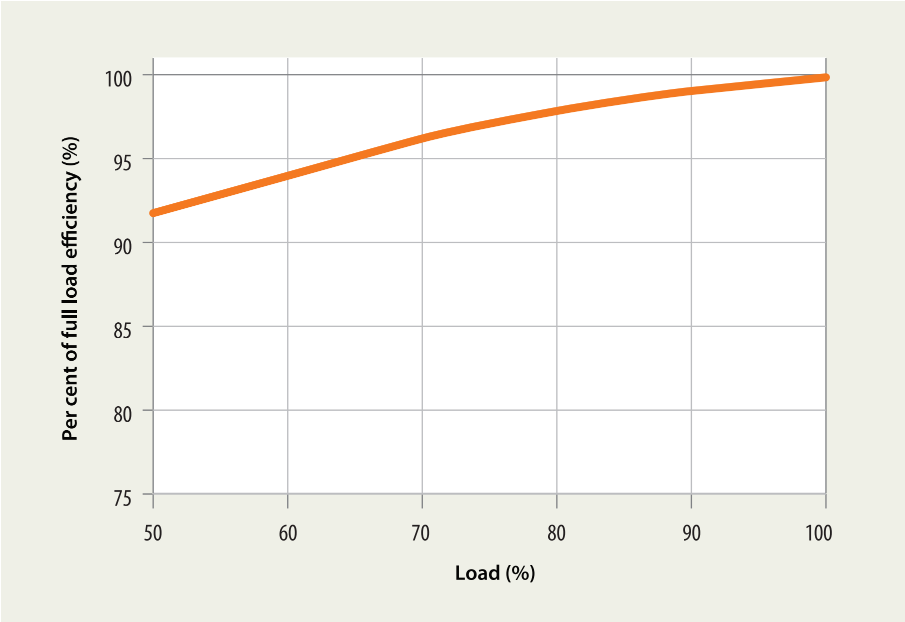


Figure 37: Reciprocating engine generator typical part load efficiency

The generator output is typically de-rated (i.e. operated at less than its rated maximum output power) at ambient temperatures above 30°C or altitudes above 500 m. The actual de-rating depends on the specific make and model of the reciprocating engine generator and manufacturers should be consulted for specific performance.

A well-maintained unit typically does not suffer from any material degradation of output over its lifetime.

Typical start-up time to full electrical load is within 10 minutes.

The key advantages and disadvantages of reciprocating engines are outlined in Table 22.

Manufacturers of such generators include:

- Caterpillar
- Cummins
- Deutz
- GE Jenbacher
- Guascor
- Mitsubishi Heavy Industries
- MTU Friedrichshafen
- MWM
- Waukesha
- Yanmar.

Table 22: Key advantages and disadvantages of reciprocating engines

Cogeneration system	Advantages	Disadvantages	Available sizes
Spark ignition reciprocating engine (1500rpm)	• High electrical efficiency • Good part load efficiency • High grade heat (exhaust) • Fast start-up • Low pressure gas fuel	• High relative maintenance costs ($/MWh) • Low grade heat from engine cooling • Relatively high emissions • Engine must be cooled if heat not used	50–4000 kW

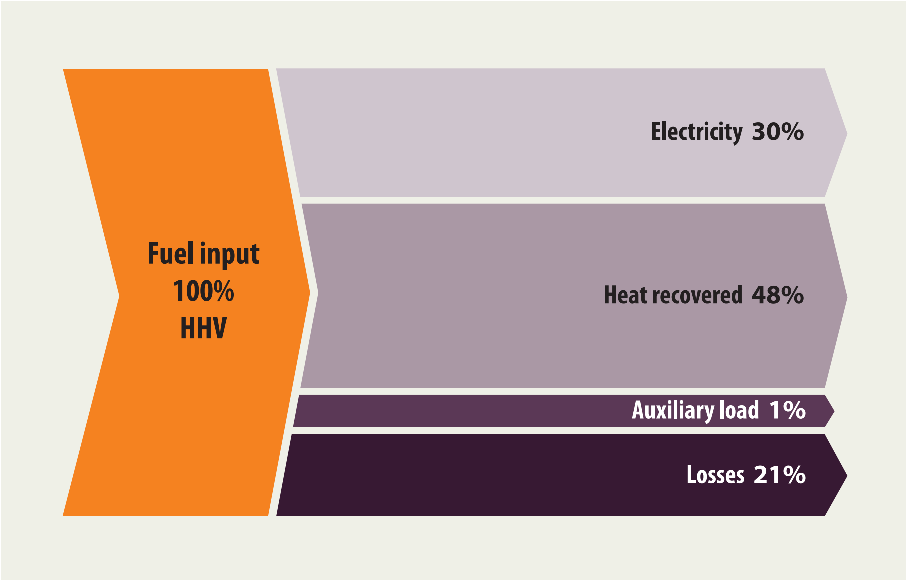
Gas turbine generator

A gas turbine generator incorporates an air compressor, a combustor, a power turbine and an electric generator. The compressor provides pressurised air to the combustor where fuel is added and burned. Hot combustion gases leave the combustor and enter the turbine section where the gases are expanded across the power turbine blades to rotate the main shaft. The drive shaft powers the compressor and the electric generator.

Heat can be recovered from the gas turbine exhaust via a heat-recovery steam generator to provide medium-pressure steam, typically up to 17,500 kPa per 210°C.

A typical energy balance for a 7500 kW gas turbine generator in a cogeneration application is shown in Figure 38.

Figure 38: Gas turbine generator Sankey diagram



The key performance parameters of a range of gas turbine generators are given in Table 23. The electrical efficiency of gas turbine generators improves with larger units, though the cogeneration efficiency is similar.

Table 23: Typical gas turbine generator performance at ISO conditions (natural gas)

Parameter	Unit	A	B	C
Electrical output (gross)	[kWe]	1200	3500	7500
Fuel input (HHV)	[kW]	5470	13,910	24,600
Fuel input (HHV)	[GJ/h]	19.7	50.1	88.5
Electrical efficiency (HHV)	[%]	22.0	25.2	30.5
Thermal output[1]	[kWt]	3100	7025	11,810
Thermal efficiency (HHV)	[%]	56.7	50.5	48.0
Auxiliary load[2]	[%]	3.0	2.5	2.0
Cogeneration efficiency (HHV)	[%]	78.7	75.7	78.5
Heat to power ratio		2.6	2.0	1.6

1. Heat recovered as saturated steam at 10 bar.
2. As a percentage of electrical output.

Gas turbines can operate over a load range from 100 per cent to 35 per cent, but the electrical efficiency reduces at part load (Figure 39).

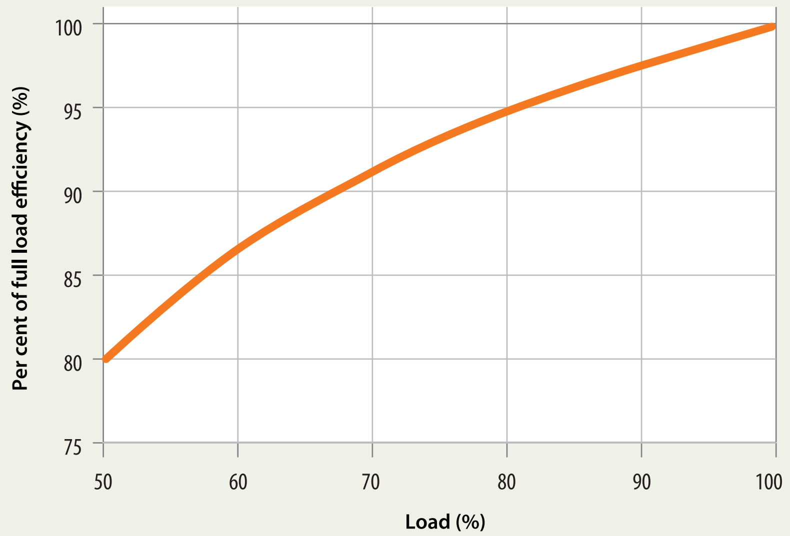


Figure 39: Gas turbine generator part load electrical efficiency

The output of a gas turbine is specified at ISO conditions of 15°C, 60 per cent relative humidity and zero metres altitude. At higher temperatures and altitudes, the gas turbine generator output will be lower, while at temperatures below 15°C, output will be higher. The effect of temperature and altitude on output is specific to the make and model of the gas turbine generator and manufacturers should be consulted for actual performance.

Gas turbine generator output and heat rate (efficiency) will degrade over the plant lifetime. Typical expected non-recoverable degradation can be of the order of 2.5 per cent reduction in output and 2 per cent increase in heat rate over the plant life. Manufacturers should be consulted for specific performance.

The typical start-up time for a gas turbine is 30 minutes to full load. The key attributes of gas turbines are highlighted in Table 24.

Manufacturers of gas turbine generators up to 10 MW include:

- Kawasaki
- MAN TURBO
- Pratt & Whitney
- Rolls Royce
- Siemens
- Solar
- Vericor.

Table 24: Key advantages and disadvantages of gas turbines

Cogeneration system	Advantages	Disadvantages	Available sizes
Gas turbine	• High reliability • Low emissions • High grade heat (exhaust) • Minimal cooling required	• Medium pressure gas fuel • Poor part load efficiency • Output falls as ambient temperature increases • Performance degrades over time	1000 to >30,000 kW

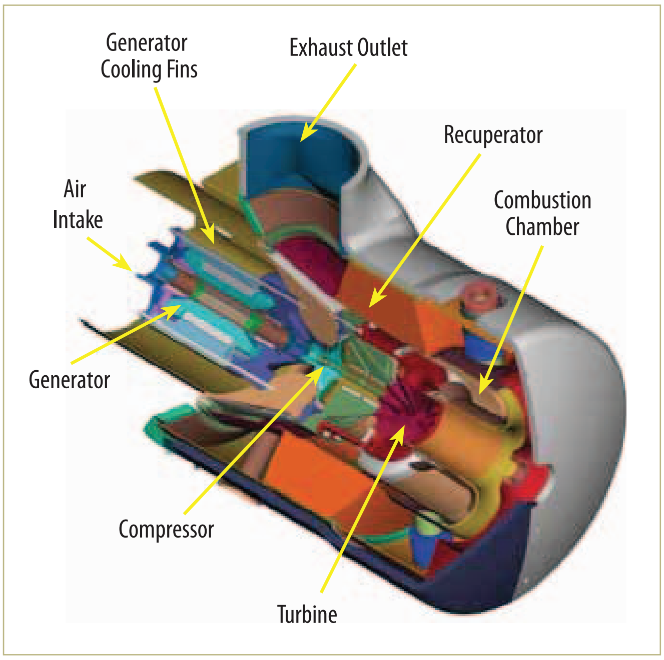
Microturbine

A microturbine is simply a smaller gas turbine with a simpler design. The system incorporates a gas compressor, recuperator, combustor, power turbine and an electric generator mounted in a noise-attenuating enclosure. Air enters the unit and is compressed to about 250 kPa in the gas generator compressor and then heated to up to 550°C in the recuperator.

A screw compressor type fuel gas booster is used to compress the natural gas fuel, the compressed air is mixed with the fuel, and the mixture is burned in the combustor under constant pressure conditions. The resulting hot gas expands through the power turbine section to perform work, rotating the turbine blades to turn a generator that produces electricity. The rotating components can be either a single shaft design with the power turbine on the same shaft as the generator or a two-shaft design with the power turbine connected to the generator on a separate shaft via a gearbox.

The generator is cooled by the air flowing into the gas turbine. The exhaust gas exits the turbine and enters the recuperator, which captures some of the thermal energy and uses it to preheat the air entering the combustor, improving the efficiency of the system. The exhaust gas then exits the recuperator through a muffler and enters the integrated heat recovery unit. A single shaft design microturbine generator is shown in Figure 40.

Figure 40: Microturbine generator



Source: Capstone Turbine Corporation

Typically the integrated heat recovery unit consists of a fin-and-tube heat exchanger, which circulates a glycol/water mixture through the heat exchanger. The heating loop is driven by an internal circulation pump and no additional pumping is required. The thermal control system is programmable for individual site requirements.

Single-shaft designs (Capstone, Elliot, Turbec) use a high-speed generator, which employs a permanent magnet alternator and requires the AC high-frequency output to be converted to 50 Hz, by an inverter. Two-shaft designs (Ingersoll Rand) use a synchronous generator to produce AC power directly at 50 Hz.

A typical energy balance for a 65 kW microturbine generator in a cogeneration application is shown in Figure 41.

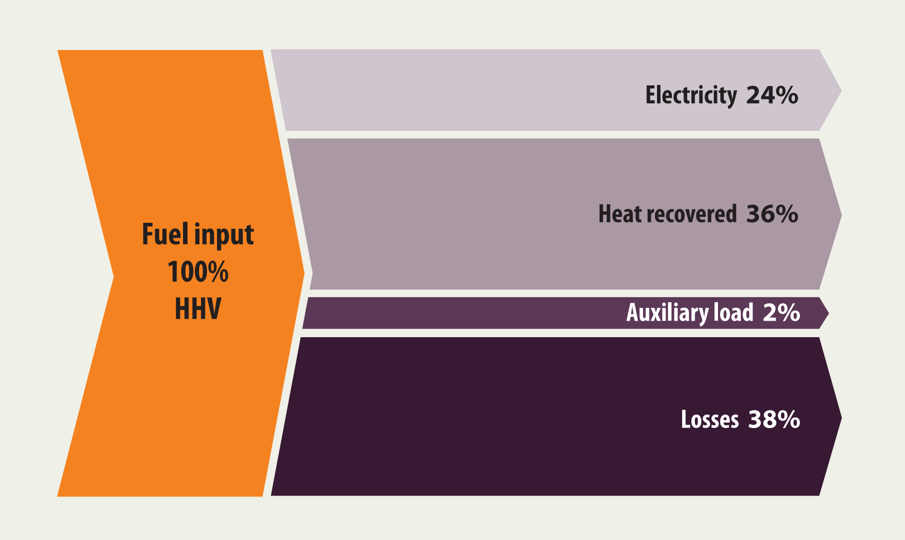


Figure 41: Microturbine generator Sankey diagram

The key performance parameters of a range of microturbine generators are given in Table 25. The electrical efficiency of microturbine generators improves with larger units, though the cogeneration efficiency is similar.

Table 25: Typical microturbine generator performance at ISO conditions (natural gas)

Parameter	Unit				
Electrical output (gross)	[kWe]	30	65	100	250
Fuel input (HHV)	[kW]	133	249	369	923
Fuel input (HHV)	[GJ/h]	0.48	0.90	1.3	3.3
Electrical efficiency (HHV)	[%]	22.6	26.1	27.1	27.1
Thermal output[1]	[kWt]	52	90	130	320
Thermal efficiency (HHV)	[%]	39.1	36.1	35.2	34.6
Auxiliary load[2]	[%]	7.0	7.0	6.0	4.0
Cogeneration efficiency (HHV)	[%]	61.7	62.2	62.3	61.7
Heat to power ratio		1.73	1.38	1.30	1.28

1. Heat recovered as hot water.
2. Including fuel gas booster.

Microturbines can operate over a load range of 10 per cent to 100 per cent, but the electrical efficiency reduces at part load (Figure 42).

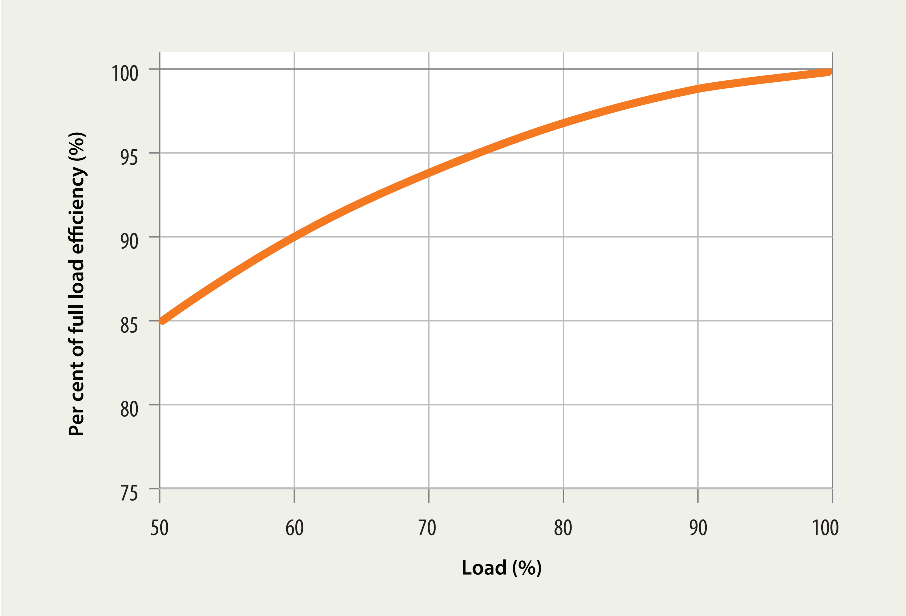


Figure 42: 65 kW Microturbine generator part-load electrical efficiency

The output of microturbines is specified at ISO conditions of 15°C, 60 per cent relative humidity and zero metres of altitude. At higher temperatures and altitudes, the microturbine generator output will be less, and conversely at temperatures below 15°C, output will be higher. The effect of temperature and altitude on output is specific to the make and model of the microturbine generator and manufacturers should be consulted for actual performance.

Microturbine generator output and heat rate (efficiency) will degrade over the plant lifetime and manufacturers should be consulted for specific performance.

The typical start-up time for a microturbine is two minutes to full load. The key attributes of microturbines are summarised in Table 26.

Manufacturers of microturbine generators include:

- Capstone
- Elliot Microturbines
- Ingersoll-Rand
- Turbec AB.

Table 26: Key advantages and disadvantages of microturbine

Cogeneration system	Advantages	Disadvantages	Available sizes
Microturbine	• High reliability – small number of moving parts • Compact size and weight • Low emissions • No cooling required	• High pressure gas fuel • High relative capital cost ($/kW) • Low electrical efficiency • Low grade heat (exhaust) • Performance degrades over time	30–250 kW

Fuel cell

While fuel cells are becoming more common in USA, they have not been used much in Australia. Likely problems are the high capital costs, the need for foreign-manufactured units to meet local design codes and lower cost for reciprocating engines delivering similar electrical and heat outputs. However, sites (such as a chloro-alkaline plant or other electrolytic process) with a waste hydrogen source would be ideal for the fuel cell as the reforming process is not required. This would significantly decrease the relative capital costs.

A fuel cell is an electrochemical cell that directly generates electricity and some heat by electrochemically oxidising fuel. This process may be accelerated by a catalyst such as a transition metal or an acid solution. Fuel cells operating at high temperatures (> 600°C) do not require catalysts.

Natural gas is first converted to hydrogen in the fuel processing system (FPS) through a process known as catalytic steam reformation. Hydrogen and air are then supplied to multiple fuel cell stacks, in which hydrogen and oxygen combine electrochemically to produce direct current (DC) electricity, heat and water. Finally, alternating current (AC) electricity is produced through a DC to AC inverter. Heat generated in the fuel cell process generates steam, which is returned to the FPS for use in the steam reformation process.

The main components of the fuel cell generator are:

- fuel processing system – removes sulphur, converts CH_4 to H_2, removes NH_3, condenses H_2O
- power supply system – electrochemical reaction of H_2 and O_2 to produce electricity and H_2O
- thermal management system – maintains thermal balance by providing cooling water to fuel cell stacks and balance of plant
- electrical system module – DC to AC inverter and grid synchronisation
- air processing system – filtering air for the fuel cell cathode and ventilation
- cooling module – air-cooled radiator for fuel cell cooling.

The fuel cell has two heat recovery interfaces via internal heat exchangers to heat water directly. These include low-grade heating delivered at a potential 60°C and high-grade HG heating delivered at a potential 120°C.

A typical energy balance for a 400 kW fuel-cell generator in a cogeneration application is shown in Figure 43.

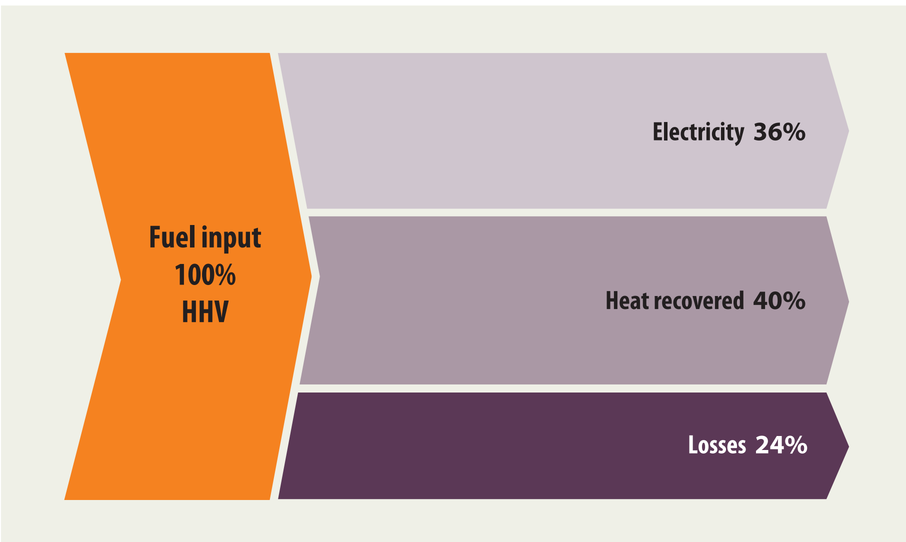


Figure 43: 400 kW fuel cell generator Sankey diagram

The above diagram gives conservative electrical output. Molten carbonate fuels cells in industrial applications (e.g. Sierra Nevada Brewery, San Francisco) have achieved in excess of 45 per cent electrical conversion with the waste heat available at 450°C.

The key performance parameters of a range of fuel cells are given in Table 27. The electrical efficiency of fuel cells improves with larger units, though the cogeneration efficiency is similar.

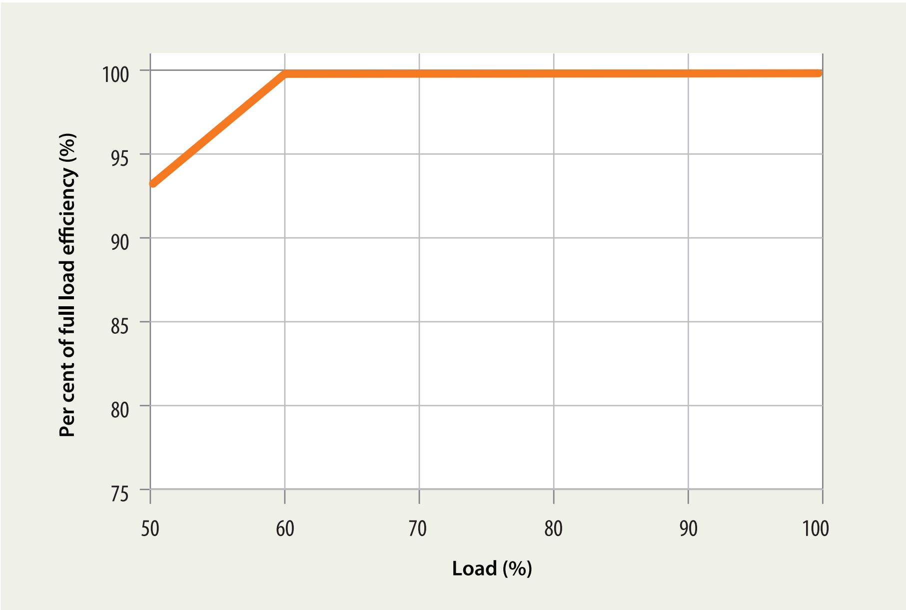
Table 27: Typical fuel cell performance (natural gas)

Parameter	Unit		
Electrical output (gross)	[kWe]	400	1400
Fuel input (HHV)	[kW]	1110	3470
Fuel input (HHV)	[GJ/h]	4.0	12.5
Electrical efficiency (HHV)[1]	[%]	36.1	40.4
Thermal output[2]	[kWt]	450	1280
Thermal efficiency (HHV)	[%]	40.5	36.9
Auxiliary load[3]	[%]	0	0
Cogeneration efficiency (HHV)	[%]	76.6	77.3
Heat to power ratio		1.125	0.914

1. Nominal over 80,000 hour lifetime.
2. Heat recovered as low temperature hot water at 60°C + high temperature hot water at 120°C.
3. Accounted for in electrical output.

Fuel cells can operate over a load range of 25 per cent to 100 per cent, but the electrical efficiency reduces at low loads (Figure 44).

Figure 44: Fuel cell generator part load electrical efficiency



The electrical efficiency of a fuel cell degrades by as much as 15 per cent (i.e. from 42 per cent to 35 per cent) over the 80,000 hour lifetime of the stack.

Typical start-up times for fuel cells are five hours to full load, during which time the average electrical load is approximately 20 per cent of rated output.

The key attributes of fuel cells are summarised in Table 28.

Manufacturers of fuel cell generators include:

- Ballard
- FuelCell Energy
- UTC Power.

Table 28: Key advantages and disadvantages of fuel cells

Cogeneration system	Advantages	Disadvantages	Available sizes
Fuel cell	• No direct emissions • Low noise • High electrical efficiency over load range • Modular design • Low pressure gas fuel • No No_x emissions	• Very high relative capital cost ($/kW) • Low durability • Very low power density • Gas fuel requires processing • Low grade heat • Fuel cell must be cooled if heat not used • Performance degrades over time	5–1400 kW

The following technologies (steam and ORC) are use generally used in 'bottoming cycle' applications. Heat is used instead of fuel to generate electricity, and therefore is useful to sites which have large amounts of existing waste heat or centralised energy generators. These types of applications are not the focus of this guide, but have been included for completeness.

Steam turbine

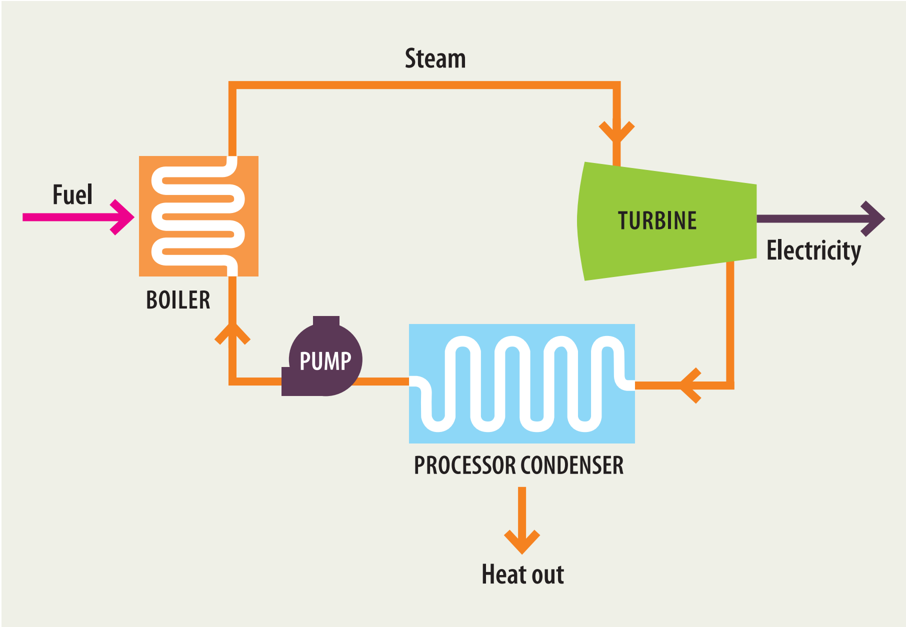
Steam turbines, like gas turbines, convert the pressure energy in a hot gas to mechanical energy. This mechanical energy can then be used to drive a generator. In some larger industrial facilities this can be used directly to drive large rotating machinery. However, the 'hot gas' driving a steam turbine is steam-generated separately in a boiler. About three quarters of Australia's electricity is generated by steam turbines in coal-fired power stations (Source: www.worldcoal.org/coal/uses-of-coal/coal-electricity/).

There are two distinct types of steam turbine, back-pressure turbines and condensing turbines. In a back-pressure turbine, high-pressure, super-heated steam is fed into the turbine and low-pressure, saturated steam is discharged and used for process heating in the facility (Figure 45). This is the traditional form of cogeneration and is typically used in larger scale industrial plants.

The main advantage of the back-pressure turbine system is that the conversion of energy in the turbine is very efficient (with most of the heat waste occurring in the boiler). They are also highly reliable.

Condensing turbines accept lower pressure steam and discharge it, often under vacuum, into a condenser. Typically, the temperature of the discharged steam is too low for its heat to be useful in the process. Therefore, this type of turbine is typically only useful for waste-heat recovery cogeneration systems.

Figure 45: Typical steam turbine cogeneration cycle



It is possible to combine a back-pressure turbine and a condensing turbine to create a cogeneration system that can vary its thermal and electrical output to follow both loads quite closely. When there is a high thermal need and low electrical need, more steam is fed to the back-pressure turbine and the condensing turbine may be bypassed. For low thermal and high electrical needs, some of the steam is fed through the condensing turbine resulting in high generation and low thermal output.

The electrical efficiency of steam turbines is highly dependent upon the flow, pressure and temperature of the steam entering and leaving the turbine. As a guide, the electrical conversions based on the energy flow in the steam through the turbine are as follows:

- back-pressure turbine, 5% to 20%
- condensing turbine, 5% to 35%.

Suppliers should be contacted for further information, these include:

- GE
- Siemens
- Elliot
- Toshiba
- many others.

Steam microturbine

Microturbines are very similar to steam turbines in that they use the energy of the pressure and temperature in steam to generate mechanical work. The main difference is that they have been designed to run at lower pressure and to use saturated steam. This is significant because they can use steam from a normal low-pressure boiler as seen at many smaller industrial facilities. This means that new boiler plant is not required, which lowers the capital cost of installing a steam turbine cogeneration system.

A steam microturbine typically operates in the same configuration as a back-pressure turbine and thus delivers similar electrical conversions. Sizes range from 80 kW to 275 kW and manufacturers include Energent.

The key advantages and disadvantages for steam turbines are shown in Table 29.

Table 29: Key advantages and disadvantages of steam turbines and steam microturbines

Cogeneration system	Advantages	Disadvantages	Available sizes
Steam turbine	• High thermal efficiencies possible • Highly reliable • Compact • Versatile in configuration • Runs on heat as opposed to fuel	• High cost at smaller sizes • High grade heat required • Low electrical conversion	80 kW to >500,000 kW

Organic Rankine cycle

ORC systems, shown in Figure 46, are thermally driven cogeneration systems like steam turbines. They use the same principles as steam turbines to generate electricity. The fundamental difference is that instead of steam an organic liquid, with a lower boiler point like a refrigerant, is used as the working fluid. This means that the system can accept heat at much lower temperatures as the input energy.

Electrical conversion of an ORC unit varies with the input temperature and the condensing temperature, but assuming typical cooling water temperatures of 35°C then indicative figures are as follows:

- 80°C to 100°C input 8–10% conversion
- 250°C input temperature ~ 20% conversion.

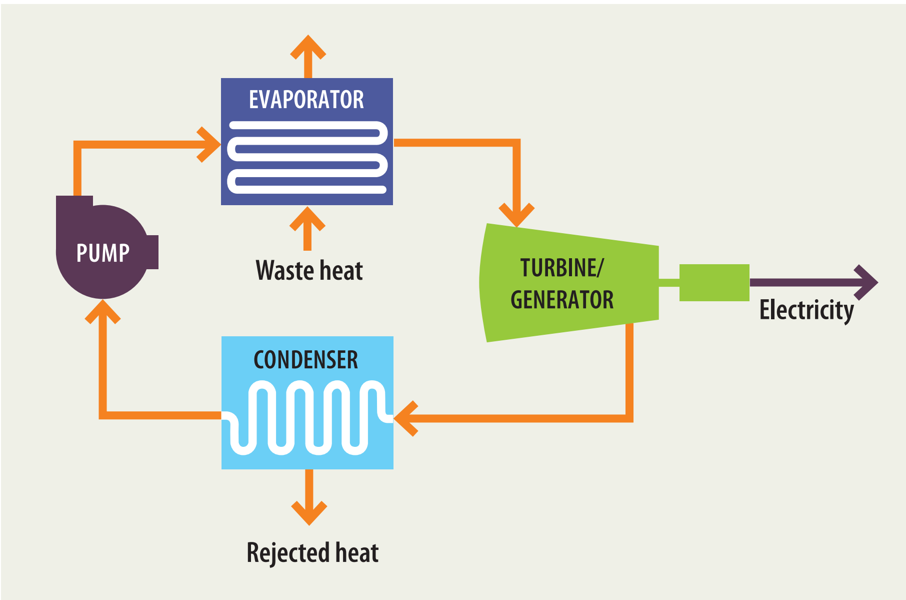


Figure 46: Organic Rankine cycle diagram

Manufacturers include:

- Pratt & Whittney
- Turboden
- G-Tet
- many others.

Thermal plant

Thermal plant is any plant that is involved in heating and cooling within a site. This appendix covers the seven key types both as part of, and separate from, a cogeneration system.

1. Natural gas-fired boilers

Gas-fired water boilers are the conventional technology used to generate hot water for commercial sites, hospitals, university campuses, laundries, leisure/aquatic centres, wastewater treatment plants and industrial applications.

Gas-fired steam boilers are the conventional technology used to generate steam for the above applications. A high-pressure steam boiler with a superheater is required to produce steam for the typical steam turbine cogeneration system.

The efficiency of natural gas-fired boilers depends on the amount of excess air and the temperature difference between the stack gas and ambient air. Gas fired boilers typically operate with 15–20% excess air, so the efficiency is primarily a function of stack gas temperature, which in turn is a function of the boiler heat transfer surface and hence cost. A small amount of heat is lost through the boiler casing, typically only 0.5–1.0%. Typical gas-fired boiler efficiency is 75–85% on a HHV basis.

Most natural gas burners require excess air at low loads because the fuel/air mixing is less effective. This results in lower efficiency at part load and a modern gas-fired package boiler with full combustion controls may drop from 80% efficiency at full load, to 75% efficiency at a minimum load of 25%.

2. Condensing gas boilers

Condensing boilers are water heaters in which a high efficiency (typically greater than 90%) is achieved. They recover as much heat as possible from hot combustion gases. Condensing boilers are able to do this because they are designed to cool the combustion gases below their water condensing (or dew) point. This maximises useable heat production by the fuel through recovering additional heat from the flue gases as well as some of the latent heat of condensation from the water.

Condensing boilers should be considered when hot water temperatures of approximately 75°C or lower are required. Lower temperatures improve efficiency due to lower flue temperatures and increased condensation.

Condensing boilers may be fuelled by gas or oil and offer several key advantages over other types of gas boilers.

High energy efficiency – with greater than 90% efficiency, condensing gas boilers are between 15% and 30% more energy efficient than older gas boilers, and around 15% more efficient overall than modern non-condensing boilers. This means a considerable reduction in running costs over the course of a year.

Environmentally friendly – because of their high efficiency, condensing gas boilers produce significantly lower CO2 emissions than other gas boilers and are therefore much kinder to the environment.

Lower fuel bills – by burning less fuel to extract the same amount of energy, condensing gas boilers result in fuel bill savings. Over time this offsets the initial higher purchase and installation cost.

Compact size – contemporary design and modern materials mean that condensing gas boilers come in a variety of compact sizes to suit your requirements and available space.

3. Solar thermal

Solar thermal is a range of technologies for harnessing solar energy to produce thermal energy. The main solar thermal technologies are used for the following:

- space heating for buildings
- hot water heating
- production of steam for electricity.

Typically, solar thermal systems are best suited to applications where temperatures are relatively low, such as swimming pool heating, domestic hot water and space heating for buildings.

Another solar technology is small-scale concentrated solar. This technology uses mirror concentration technologies and can be used to produce higher temperatures (up to 200°C) and therefore can produce steam for electricity generation. The capital costs for this technology is currently high.

4. Heat pump – ground source

Ground source heat pumps provide winter heating by extracting heat from the ground subsoil and transferring it into a building at a higher temperature, taking advantage of the subsoil's daily and seasonally-moderated temperature.

In the summer, the process can be reversed so that the heat pump extracts heat from the building and transfers it to the ground, which is typically significantly cooler than the air temperature during the hot part of the day. Transferring heat to a reduced temperature uses less energy, so the pump benefits from the lower ground temperature.

Ground-source heat pumps employ a heat exchanger in contact with the ground or groundwater to extract or dissipate heat. This component accounts for up to half of the total system cost and is cumbersome to repair or replace.

5. Heat pump – air source

An air-source heat pump uses ambient air as its heat source and heat sink. The main components of an air-source heat pump are:

- an outdoor heat exchanger coil, which extracts heat from ambient air
- a refrigerant circulation unit
- an indoor heat exchanger coil, which transfers the heat into a water tank or indoor heating system, such as radiators or under-floor circuits.

Air source heat pumps can provide relatively low cost space heating.

6. Exhaust heat recovery

Exhaust heat recovery systems are boilers which are installed in the hot exhaust streams of reciprocating engines, gas turbines or microturbines. They are typically used in applications where exhaust temperatures are in excess of 300°C and produce steam or hot water depending on the application.

The efficiency of exhaust heat recovery does not vary appreciably with load.

7. Heat exchangers

Heat exchangers are designed to transfer heat from one medium to another as efficiently as possible. In cogeneration systems, they are typically used to recover waste heat from hot fluids such as cooling water and lube oil systems and are commonly used with reciprocating engines, microturbines and fuel cells.

Heat exchangers can be of the multi-plate type or of the shell-and-tube type. The type of heat exchanger selected should be based on a number of factors, including:

- medium, i.e. liquid or gas or both
- temperature (high temperatures may require specific materials of construction)
- pressure
- material compatibility (e.g. for corrosion)
- delta T (small temperature differences across heat exchangers lead to higher or lower available temperatures and due to thermodynamics in many applications will increase the overall system efficiency).

Thermally-driven cooling

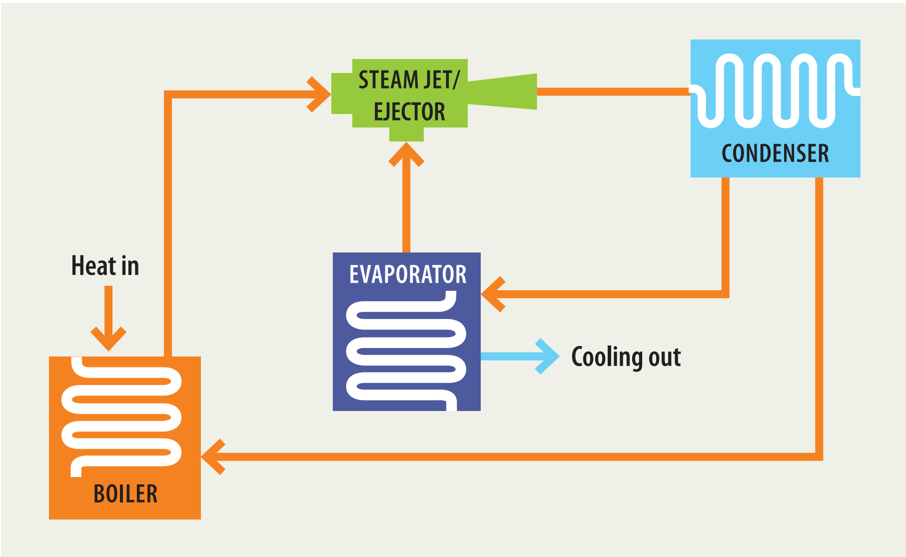
A number of technologies can convert heat into cooling. Only those most relevant to this guide are covered in this section. Table 30 gives an indicative summary. For specific pricing and technical specifications contact the product suppliers.

Table 30: Thermally-driven cooling technologies

Technology	Capital cost $AUD/kWr	Operational cost	Input temperature	Cooling temperature	COP
Steam jet/ejector	$200–$300	Lowest	> 100°C	> 10°C	< 1
One-stage absorption chiller	$150–$250	Low	> 80°C	> 5°C	< 0.8
Two-stage absorption chiller	$200–$350	Low	>150°C	> 5°C	< 1.4
Electric chiller	$100–$200	Medium	N/A - electricity	Very cold, <-60°C	< 10

Steam jet/ejector chiller

Figure 47: Steam jet/ejector refrigeration process



A steam jet or ejector chilling process is shown in Figure 47. The steam jet, or thermo compressor, uses the energy in pressurised steam to draw a vacuum on a tank of water. The water then boils at the low pressure and temperature to create cooling.

These systems are very simple and reliable because there are no moving parts. However, they do not have very good turn down and require motive steam as the input energy.

Absorption chillers

Absorption chillers take energy from a heat source to drive the cooling process. They are commonly used in trigeneration systems where they use waste heat from a reciprocating engine, gas turbine, microturbine or fuel cell and produce chilled water for cooling loads. They can displace or reduce the use of electric chillers.

Both adsorption and absorption chilling methods of refrigeration use a substance that can adsorb or absorb a refrigerant (usually water). By doing so, the pressure of the refrigerant gas inside the sealed system is lowered, which makes the liquid refrigerant boil and performs the cooling. In these systems, the section where the refrigerant boils corresponds with the evaporator and the absorption/adsorption process corresponds with the compressor (as it creates the pressure differential) in a traditional mechanical compression refrigerant system. In both systems, heat is used to regenerate the absorbing/adsorbing material (to drive out the refrigerant) in another sealed section. These systems are thermally rather than electrically-powered.

Some of the advantages of absorption chillers compared to electric chillers are:

- elimination of the use of freon refrigerants (chlorofluoro carbon or CFC)
- quiet, vibration free operation
- no large rotating components
- utilisation of waste heat (as generator heat source)
- reduced electricity consumption.

Some of the disadvantages of absorption chillers compared to electric chillers are:

- installation costs are higher
- thermal efficiency (coefficient of performance) is lower
- more pump energy is needed
- larger cooling tower capacity is required.

Absorption chillers have a number of practical limitations that limit their application and influence the feasibility of a trigeneration system:

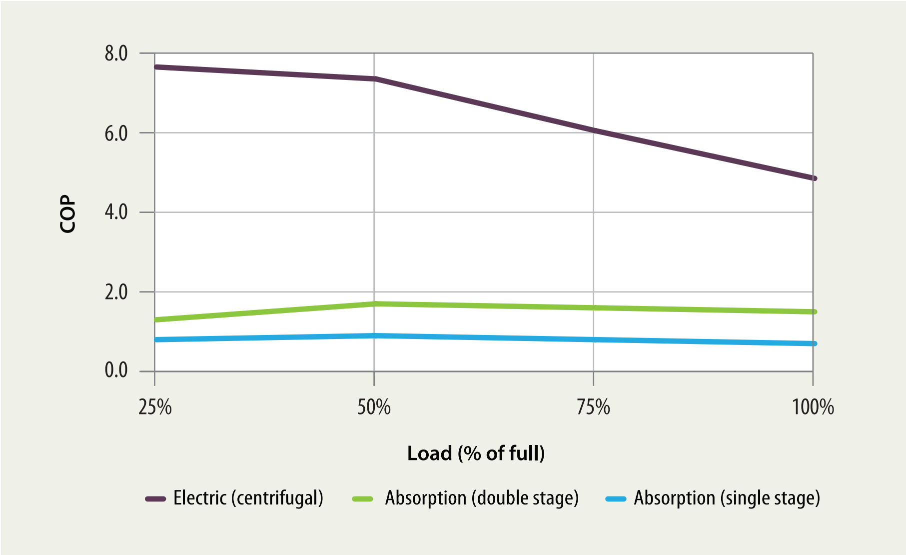
- absorption chillers can typically produce chilled water with a minimum temperature of approximately 5°C. However, they are better suited to higher temperatures of 7–10°C where their thermal efficiencies are improved. This would typically be suitable for HVAC applications but less so for industrial or cold store applications where colder temperatures are required
- cooling load is frequently seasonal (e.g. air-conditioning load is generally for only 3–5 months of the hotter periods of the year) and use of an absorption chiller for the load may be low, and therefore poorly justified financially
- absorption chillers require a significant quantity of cooling water compared to electric chillers due to their relatively low efficiencies. For example, an absorption chiller with a coefficient of performance (COP) of 0.7 would require 2430 kW of cooling to produce 1000 kW of refrigeration duty. This is double the cooling requirement for the same cooling capacity produced by an electric chiller with a COP of 5.0 which would have a cooling load of 1200 kW. The cost of providing cooling water should be considered when evaluating trigeneration schemes
- single effect absorption chillers are relatively expensive compared to electric chillers. Double effect chillers are more efficient but are significantly more expensive than single effect chillers. If absorption chiller use is relatively low, it will be difficult to achieve a reasonable financial payback.

The heat input to absorption chillers can come from a variety of sources including hot water, steam and direct fired (either through a burner or exhaust gases).

Several different refrigerants can be used and the choice will affect the range of cooling temperatures achievable. Lithium bromide is commonly used in commercial applications and will produce chilled water at approximately 5°C to 7°C.

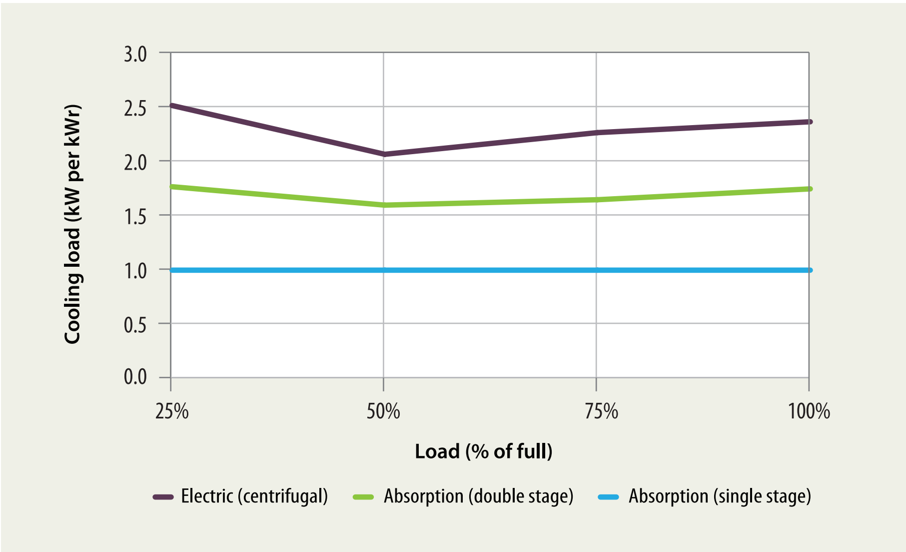
Absorption chillers can be single or multi-stage. Two-stage chillers have higher temperature input and are more efficient than single-stage chillers, but this requires additional capital expense. Typical two-stage absorption chillers have a COP of 1.3–1.4 and single-stage chillers have typical COPs of 0.7–0.8. This compares to electric chillers which have typical COPs in the range of 3.5–8.0. Typical COPs as a function of load for electric (centrifugal), absorption single-stage and absorption two-stage chillers are shown in Figure 48. The COP at the average annual load of the chiller plant should be used in evaluating trigeneration.

Figure 48: Chiller COP as a function of load



Absorption chillers require cooling, which is generally achieved using a cooling tower. They have a higher cooling load than equivalent-sized electric chiller (Figure 49). If an absorption chiller replaces an electric chiller, the additional cooling load must be provided.

Figure 49: Chiller cooling load as a function on load (kW per kWr)



Direct-fired, hot-water and steam chillers can typically operate at loads of 10–100% of the design capacity.

Manufacturers of the various types of chillers include, but are not limited to:

- Broad
- Carrier
- CHP Solution Inc.

- Mitsubishi Heavy Industries
- Sanyo
- Shuangliang
- Thermax
- Trane
- York.

Absorption chiller – direct-fired (exhaust)

In cogeneration applications, direct-fired absorption chillers use hot gas produced by the exhaust gas from a reciprocating engine, gas turbine or microturbine. They are suitable for applications where only chilled water is required.

Single-stage direct fired absorption chillers accept exhaust gas at temperatures up to 300°C, which is cooled to approximately 130°C, and are suitable for microturbine applications.

Two-stage direct-fired absorption chillers accept exhaust gas at temperatures up to 500°C, which is cooled to approximately 170°C, and are suitable for reciprocating engine and gas turbine applications.

Absorption chiller – hot water

In cogeneration applications, hot water absorption chillers use hot water produced from a gas engine, microturbine or fuel cell. Hot water absorption chillers are suitable for applications where both hot water and chilled water are required.

Single-stage hot water absorption chillers typically accept hot water at 90°C which is cooled to approximately 80°C.

Two-stage hot water absorption chillers typically accept hot water at 180°C which is cooled to approximately 165°C.

Absorption chiller – steam

In cogeneration applications, steam absorption chillers use saturated steam produced from a gas engine (exhaust heat) or gas turbine. Steam absorption chillers are suitable for applications where both steam and chilled water are required.

Single-stage steam-absorption chillers typically accept steam at 100 kPag and 120°C which is returned as condensate at approximately 95°C.

Two stage steam-absorption chillers typically accept steam at 800 kPag and 175°C which is returned as condensate at approximately 95°C.

Absorption compared to adsorption

The fundamental difference between adsorption and absorption systems is that in adsorption systems the material that adsorbs the refrigerant is a solid whereas in absorption the material is a liquid. This leads to significant differences is design, with absorption chillers normally being continuous processes in which the absorption fluid flows between cooling and regeneration sections. An adsorption system typically requires two separate units or zones with one providing cooling while the other is being regenerated.

Absorption chillers are far more common and are available from a large range of manufacturers. Commercially-available adsorption chillers are relatively uncommon and are still only available from a handful of suppliers in sizes suitable for cogeneration systems.

The criteria for selection are primarily price, COP and the cooling temperatures required. Other considerations, such as the toxicity of the substances used in the equipment, can also be important.

As a general rule, water-based absorption chillers have a slightly higher efficiency but require a minimum temperature input of around 85°C, whereas for adsorption, temperatures of 75°C can be used, but efficiencies are lower. Water-based absorption chillers can cool to around 5°C whereas adsorption chillers can cool to –15°C. There are also ammonia-based absorption chillers which require higher input temperature (minimum of around 130°C) and can cool as low as –60°C. However, their efficiency is lower again. As with all thermodynamic cycles, the efficiency depends on the temperature differentials. So lowering the cooling temperature lowers the efficiency, and increasing the input heat temperature or lowering the heat rejection temperature improves efficiency.

Additional cogeneration thermal plant

Waste heat rejection

Waste heat rejection is an important consideration in the design of a cogeneration system, as it adds capital and operational costs and also has environmental implications when water is evaporated for heat rejection. Cogeneration systems should be designed so that the heat rejection requirements are minimised whilst maintaining functionality.

Cooling towers

Wet mechanical-draft cooling towers can be used to provide cooling of the lubricating oil, intercooler and jacket water of a reciprocating engine. However, they are open systems (i.e. contaminants can enter the system), and they are less reliable than air-cooled radiators. Typically, cooling towers have higher operating and maintenance costs (water consumption and chemicals) than radiators, and so they are not preferred for this application.

These cooling towers are typically used for absorption chiller cooling. An absorption chiller requires cooling water inlet temperature of 25–30°C and an outlet temperature of 35–40°C. Should the design cooling water temperature of the absorption chiller be higher than that for the electric chiller, a dedicated cooling tower may be required for the absorption chiller rather than a common cooling tower shared with electric chillers.

Air-cooled radiators

Air-cooled radiators are generally preferred to cool the lubricating oil, intercooler and jacket water of a reciprocating engine, as they offer the required reliability. They are also used for water cooling of fuel cell stacks and for cooling gas turbine lubricating oil. The air-cooled radiator rejects waste heat that cannot be utilised to the atmosphere.

Radiators must be placed in a suitable outdoor location with relatively unobstructed airflow. If the location is remote from the cogeneration unit, the additional water piping to and from the radiator, water pumping load and electrical supply to the radiator may be additional expenses.

Fuel sources

Cogeneration plants of the scale under consideration in this guide are predominantly fuelled by natural gas.

Cogeneration plants at wastewater treatment facilities are the main exception to this as they may be fuelled by biogas, which is classified as a renewable fuel. Wastewater treatment in larger facilities involves anaerobic digestion where, in the absence of oxygen, bacteria digest residual solids and create methane-rich biogas as a by-product. The biogas must be treated to remove contaminants such as hydrogen sulphide, water and solids.

The clean biogas is used by a cogeneration plant (typically a gas engine) to produce electricity to power the internal load of the plant and provide heat to the digestion process. Where biogas production levels are low or highly variable, dual fuel mixing can be used to supplement the biogas with natural gas from the mains distribution network.

Liquid fuels, such as diesel, ethanol and LPG are generally too expensive to be viable for cogeneration applications. At larger scales, waste products and biomass or even waste heat can be used to generate heat to drive steam turbines or ORC systems. The cost of these systems is reducing and if the fuel is cheap enough; free; or even in the case of wastes has negative cost, then the additional capital associated with installing such a system may be justified.

Generators

As generators are generally incorporated into the prime mover and sold as a single unit they have not been separated out and discussed in detail here. Please contact suppliers for more information.

Appendix 3: Plant dimensions and weight

Approximate dimensions and masses of various types of cogeneration units are given in Table 31.

Table 31: Approximate dimensions and mass of cogeneration units

Plant	Capacity [kWe]	Length [mm]	Width [mm]	Height [mm]	Mass [kg]	Comment
Gas engine	100	3,600	1,050	2,050	3,200	Packaged engine + generator including heat recovery
Gas engine	500	4,000	2,200	2,200	8,000	Engine generator + only, excluding heat recovery
Gas engine	1,067	6,000	2,300	2,300	11,500	Engine + generator only, excluding heat recovery
		4,700	1,800	3,750		Heat recovery module
Gas engine	2,000	8,000	2,300	2,800	20,000	Engine + generator only, excluding heat recovery
Gas engine	2,000	13,000	4,000	4,000	46,000	Engine + generator in enclosure, excluding heat recovery
Gas turbine	1,200	6,100	1,800	2,800	14,000	Enclosure only, excluding inlet air filter and heat recovery
Gas turbine	3,515	10,000	2,500	6,590	40,000	Enclosure and inlet air filter, excluding heat recovery
		12,500	2,500	4,500		Heat recovery steam generator
Gas turbine	7,500	12,600	2,900	9,400	68,000	Enclosure and inlet air filter, excluding heat recovery
Microturbine	30	1,500	800	1,800	405	Enclosure, excluding fuel gas booster and heat recovery
Microturbine	65	2,200	800	2,400	1,000	Enclosure, excluding fuel gas booster and heat recovery
Microturbine	250	4,200	2,200	2,400	5,500	Enclosure including heat recovery, excluding fuel gas booster
Fuel cell	400	8,740	3,350	3,020	28,000	Integrated package in enclosure
Fuel cell	1,400	17,000	12,000	4,300	100,000	Including fuel cell module, electrical BOP, mechanical BOP

For full confirmation on dimensions and specific unit properties please refer to relevant supplier information.

Appendix 4: Operations and maintenance

Operating and maintenance costs of a cogeneration plant are significant and can affect the feasibility of a cogeneration project. For indicative operation and maintenance costs please see section 10.

Operating requirements

The operating requirements of a cogeneration plant vary depending on the size of the plant and the technology used.

Daily inspections should include the following checks:

- lubricating oil levels
- oil leakage around the unit
- loose fasteners, pipe and tube fittings and electrical connections
- inlet air and ventilation air filters
- exhaust system
- control and monitoring system indicator lights.

Maintenance requirements

Scheduled maintenance and breakdown maintenance are typically undertaken by the original equipment manufacturer (OEM) or their Australian agent.

Key considerations for a cogeneration maintenance contract are:

- term of contract
- scope of services
- pricing
- guarantees (parts and timeframes to respond to requests).

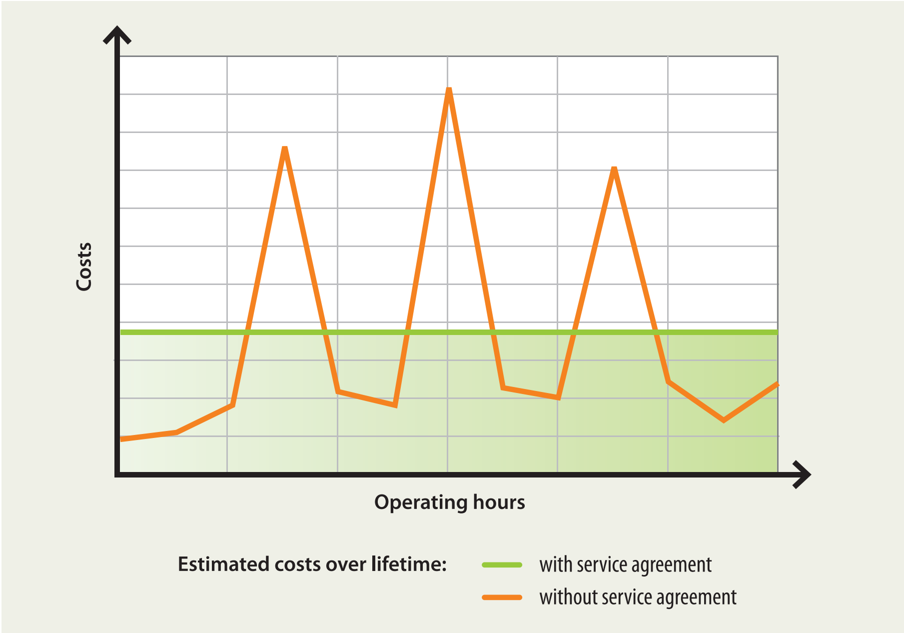
The term of the maintenance contract may either be a fixed period (e.g. five years), often with an option to extend for a second fixed period, or for a specific number of cogeneration operating hours (e.g. up to and including the first major overhaul).

The scope of services offered can be tailored to suit the capability of the cogeneration owner, and may include:

- parts and consumables for scheduled maintenance
- labour for scheduled maintenance
- breakdown maintenance and repairs
- minor overhauls
- major overhauls
- remote monitoring
- lubricating oil service.

The maintenance contract pricing depends on the scope of services and level of risk assumed by the maintenance contractor. Typically the maintenance contract defines part costs, consumable costs, labour rates and other expenses and includes escalation provisions. The maintenance costs will vary from year to year depending on the maintenance schedule, i.e. significantly higher costs will be incurred in overhaul years. Some OEMs offer long term service agreements (LTSAs) where the maintenance costs are smoothed over the contract term (Figure 50).

Figure 50: Maintenance costs over plant lifetime



Source: GE Jenbacher

The maintenance contract may also include guarantees on:

- performance (electrical output, heat rate, thermal output)
- plant availability
- breakdown response time.

Typically, for cogeneration plants of the capacity considered by this guide, only consumables (chemicals, lubricants, filter elements) and minor spares are held on site. The majority of spare parts are held by the maintenance contractor or the OEM.

Reciprocating engines

Reciprocating engines typically have higher maintenance requirements than other technologies. A typical maintenance schedule for a reciprocating engine generator is given in Table 32. Recommended maintenance requirements will vary depending on the engine manufacturer and model.

Table 32: Typical reciprocating engine maintenance schedule

Activity	Frequency	Scope
Weekly checks	Weekly	Check spark plugs and lube oil condition.
Monthly checks	Monthly	Inspect battery.
Yearly checks	Yearly	Check smoke warning system, coolers, cooling water quality.
Routine inspection and maintenance	2000 operating hours	Inspection/maintenance of heat exchangers, gas piping (leak check), valve clearance, ignition system, coolers, air intake filter, vents, regulators and throttle valves and gas supply train.
Routine inspection and maintenance	4000 operating hours	Inspect generator
Routine inspection and maintenance	10,000 operating hours	Inspect/maintain turbo charger, cooling water pumps, starter and gas mixer.
Minor overhaul	30,000 operating hours	Inspect/maintain compressed air starter, pistons, con rods, cylinder linings, crankshaft bearings, camshaft, cooling water (replace).
Major overhaul	60,000 operating hours	Inspect/maintain engine oil pumps, heat exchangers. Cylinder heads replaced as required.

Gas turbines

Gas turbines have limited moving parts so they require less maintenance. A typical maintenance schedule for a gas turbine generator is given in Table 33. Recommended maintenance requirements will vary depending on the gas turbine manufacturer and model.

Table 33: Typical gas turbine maintenance schedule

Activity	Frequency (operating hours)	Scope
Basic maintenance	Every 2000	Visual inspection of the unit. Check proper operating conditions of the equipment and investigate any unusual conditions. The visual inspection should include checking for evidence of leaks, wear or cracks. A lube oil sample is taken and tested.
Semi-annual maintenance	4000	More detailed inspection of the unit with some disassembly. Inspection typically includes inspection of instrumentation and calibration checks, disassembly and cleaning of valves, inspection of the combustors and fuel nozzles and inspection of the compressor section. Clean the entire package.
Annual maintenance	8000	Includes the above maintenance. Also includes additional activities, such as cleaning the generator, realigning gearbox and generator, disassembly and cleaning of the coupling.
Major overhaul	30,000	Complete disassembly down to component level, inspection and refurbishment of the equipment. Any major upgrades would also be installed at this time. The machine is completely rebuilt and tested following the overhaul. It is common to involve the OEM in the major overhaul.

Microturbines

Similar to gas turbines, microturbines have limited moving parts which results in limited maintenance. A typical maintenance schedule is given in Table 34. Recommended maintenance requirements will vary depending on the microturbine manufacturer and model.

Table 34: Typical microturbine maintenance schedule

Frequency	Scope
24 months	Replace batteries
4000 operating hours	Inspect air filters and clean if required. Leak check on fuel system.
8000 operating hours	Replace turbine air inlet filter, air/oil separator on the fuel-gas booster and igniters. Change fuel gas booster oil.
20,000 operating hours	Replace fuel gas booster compressor, injector assemblies and thermocouples.
40,000 operating hours	Major overhaul: replace turbine and various electronic components with remanufactured or new parts.

Fuel cell

Fuel cells have minimal moving parts and thus require limited maintenance. The majority of maintenance is for the balance of plant systems such as air-cooled radiator, cooling water pumps and heat exchangers. They are reported to be achieving annual availabilities of greater than 95 per cent with only a few days of routine maintenance per year.

The fuel cell stack itself has a typical life of 20 years and usually requires major overhaul after 10 years, which involves the replacement of major components.

Absorption chillers

Absorption chillers have minimal moving parts and thus require limited maintenance. A typical recommended maintenance schedule for a lithium bromide absorption chiller is shown in Table 35. Recommended maintenance requirements may vary depending on the absorption chiller manufacturer and model.

Table 35: Typical absorption chiller maintenance schedule

Frequency	Scope
Monthly	Check non-condensable accumulation rate and the 3-way control valve for leaks.
6-monthly	Check the thermostat and pressure transmitter switch operation, blow down refrigerant, check octyl alcohol and change as required, take sample solution for analysis.
Yearly	Check tubes for scale and fouling in evaporator, absorber, condenser and generator. Clean as required.
3-yearly	Replace manometer, diaphragm valve rubber gaskets, sight glasses and V-belts of purge pump. Check and replace palladium cell heater.
5-yearly or 20,000 operating hours	Inspect solution and refrigerant pumps, hot water 3-way valve actuator and the components in the control panel and replace as necessary.

Appendix 5: Regulations and requirements

Development approval

Development approval for cogeneration plants in NSW is subject to the requirements of the *Environmental Planning and Assessment Act 1979* (EP&A Act) and the *Environmental Planning and Assessment Regulation 2000* (EP&A regulations).

Local approval

Cogeneration plants in local government areas are likely to be proposed within lands zoned by that local government's Local Environmental Plan (LEP). Within these zones, development such as cogeneration plants may be either permissible without consent, permissible with consent or prohibited.

State Environmental Planning Policy (Infrastructure) 2007 is relevant to the development of cogeneration plants. Division 4 of this regulation deals with electricity generation works. Clause 34 (1) states that 'development for the purpose of electricity generating works may be carried out by any person with consent on any land in a prescribed rural, industrial or special-use zone'. On this basis, if cogeneration development is prohibited or not permissible without consent under the local plan, it would still be able to be undertaken with consent in a prescribed rural, industrial or special use zone. Those zones are defined in clause 33 of the State Environment Planning Policy (Infrastructure) 2007.

Local development

Development that is permissible with consent would normally be subject to a council's development approval processes under Part 4 of the EP&A Act. The process usually requires the lodgement of a development application and supporting environmental documentation. Such an application for an electricity generating works, if it is private infrastructure valued at more than $5 million, would be referred to a joint regional panel for determination.

The nominal assessment period for local approval is 40 days from the date of lodgement of the development application (the deemed refusal period). The preparation of the development application and statement of environmental effects (SEE) may take some months before lodgement, depending on the details required.

Designated development

Schedule 3 of the EP&A Regulation (designated development) identifies development that would require the preparation of an environmental impact statement (EIS) to accompany the development application. Clause 18 (1) (c) of the schedule applies to electricity generating stations that can supply more than 30 MW of electrical power and states they require an EIS. No EIS is required for cogeneration up to 10 MW. It should be noted, however, that clause 37a of Schedule 3 states that if the cogeneration plant is ancillary to other development and not proposed to be carried out independently of that other development, then the proposed cogeneration is not designated.

The nominal assessment period for designated development is 60 days from the date of lodgement of the development application (the deemed refusal period). The preparation of the DA and EIS may take some months before lodgement, depending on the requirements for the content of the EIS issued by the Director-General of Planning and Infrastructure. The mandatory exhibition time for an EIS is no less than 30 days and this is included in the 60 days deemed refusal period.

State Significant Development

A cogeneration project is a 'State Significant Development' if it has an estimated capital investment value of greater than $30 million, (or greater than $10 million if the unit is to be located in an environmentally sensitive area). State Significant developments need consent from the Minister for Planning and Infrastructure and a development application must have an Environmental Impact Statement (EIS).

Environmental consents

Following development consent for a cogeneration plant there may be a requirement for further environmental approvals to be obtained for the project.

Depending on the size of the plant and its location, an environmental protection licence (EPL) may be required. If an EPL already exists for a site where cogeneration is proposed, the existing EPL may need to be updated to include the requirements for the new plant.

Schedule 1, Part 1 (Premise-based activities) of the *Protection of the Environment Operations Act 1997* (POEO) lists the scheduled activities for which an EPL is required.

Air emissions

Cogeneration may be classified as a 'scheduled activity' and therefore be may be subject to air emissions regulations under the Protection of the Environment Operations (Clean Air) POEO Regulation (CAPER) 2010. For the types of cogeneration plants being considered by this guide, only gas engine and gas turbine plants may be subject to emission regulations with the key pollutant for consideration being oxides of nitrogen (NO_X).

Schedule 3 of CAPER 2010 standards of concentration for scheduled premises: general activities and plant, sets out the following emission standards for stationary reciprocating internal combustion engines and turbines:

Table 36: NO_x emission standards for small to medium scale generators

Nitrogen dioxide (NO_2) or Nitric oxide (NO) or both, as NO_2 equivalent	Stationary reciprocating internal combustion engines (commercial and light industrial)	450 mg/m^3
	Any turbine operating on gas, being a turbine used in connection with an electricity generating system with a capacity of less than 10 MW (light to heavy industrial and large scale commercial)	70 mg/m^3
	Any turbine operating on gas, being a turbine used in connection with an electricity generating system with a capacity of 10 MW or greater but less than 30 MW (heavy industrial and small scale stationary power generation)	70 mg/m^3
	Any turbine operating on a fuel other than gas, being a turbine used in connection with an electricity generating system with a capacity of less than 10 MW (light to heavy industrial and large scale commercial)	90 mg/m^3
	Any turbine operating on a fuel other than gas, being a turbine used in connection with an electricity generating system with a capacity of 10 MW or greater but less than 30 MW (heavy industrial and small scale stationary power generation)	90 mg/m^3

The emission limits do not take into account site-specific features such as meteorology and background air quality, and therefore do not necessarily protect against adverse air quality in the areas surrounding the premises. These site-specific features are accounted for in an air quality impact assessment as part of the development approval process.

Interim NO_x policy for cogeneration

The NSW Office of Environment and Heritage has released an Interim *NO_X Policy for Cogeneration in Sydney and the Illawarra* which sets out a framework for dealing with emissions from cogeneration and trigeneration proposals. This more stringent requirement is necessary, as air quality in Sydney and the Illawarra currently exceeds the *National Environment Protection Measure for Ambient Air Quality.*

One of the concepts introduced in the interim policy is best available techniques (BAT) emission performance.

Best available techniques covers all aspects of a proposal including fuel source, technology selection and controls. It is interpreted by the OEH as meaning the most effective and advanced stage in the development of activities and their methods of operation. It indicates the practical suitability of particular techniques for providing a basis for emission limit values designed to prevent, or at least to reduce, emissions and the impact on the environment as a whole.

Natural gas-fired reciprocating internal combustion engines

While the CAPER 2010 sets emission standards for gas engines and gas turbines (refer above) the NOX emission standard considered by OEH to be BAT for natural gas-fired reciprocating internal combustion engines with a capacity to burn less than 7 MJ of fuel per second (equivalent to approximately 2.7 MW_e output) are considered more stringent than those in CAPER and are outlined in Table 37. For natural gas-fired stationary reciprocating internal combustion engines with a capacity greater than or equal to 7 MJ of fuel per second, BAT will be determined on a case-by-case basis. The Environmental Protection Authority should be contacted for the specific requirements for such engines.

Outside the Sydney and Wollongong metropolitan area and the Wollondilly local government area, the NO_X emission standard is 450 mg/m^3, as defined in CAPER, 2010.

Table 37: NO_X BAT emission standard for natural gas-fired reciprocating internal combustion engines with a capacity to burn less than 7 MJ of fuel per second

Activity or plant	Air impurity	Region	Emission standard mg/m^3 *
Any natural gas-fired stationary reciprocating internal combustion engine	Nitrogen dioxide (NO_2) or nitric oxide (NO) or both, as NO_2 equivalent	Sydney and Wollongong metropolitan area# and Wollondilly local government area	250

* Reference conditions: Dry, 273 K, 101.3 kPa, 5% O2
# Defined in the Protection of the Environment Operations (Clean Air) Regulation 2010

No NO_X emission standard for larger natural gas-fired reciprocating internal combustion engines has been proposed. Allowable values are determined on a case by case basis.

The Environmental Protection Authority should be contacted for the specific requirements for such engines.

Appendix 6: Full engineering feasibility report outline

If, after following this guide, the cogeneration project appears feasible, the following is an example of what you should find in a detailed full engineering feasibility report.

The report provides sufficient detail to present a business case. Typical content is outlined in the following sections.

Executive summary

Summary of key findings:

- NPV
- payback
- capital cost
- IRR
- impact on site during implementation.

Energy supply

The electricity supply to the facility is described in terms of:

- network service provider
- electricity retailer
- supply voltage
- number of feeders
- location of facility's main switchboard
- contract tariffs and terms.

The natural gas supply to the facility is described in terms of:

- gas network provider
- natural gas retailer
- supply pressure (minimum, typical, maximum)
- supply capacity (GJ/h)
- location of metering station(s)
- contract tariffs and terms.

Existing plant

Existing electrical plant within the facility is described, including:

- main switchboard
- distribution ring mains
- substations
- switchboards
- standby generation plant
- electric chillers
- other large electrical loads.

Much of this information is typically contained on the facility electrical single line diagram.

Existing natural gas-fired plant within the facility is described, including:

- steam boilers
- hot water boilers.

Existing mechanical plant within the facility is described, including:

- steam reticulation
- main steam users (sterilisers, process heating, dryers, laundry)
- calorifiers
- condensate return
- hot water reticulation
- main hot water users (e.g. space heating, domestic hot water, laundry)
- chilled water reticulation
- chilled water storage (if any).

Much of this information is typically contained in the facility's steam, hot water and chilled water system schematics (if available).

Electrical and thermal loads

As a minimum, electrical daily load profiles for typical summer and winter days are established and evaluated.

As a minimum, thermal (hot water, steam, chilled water) daily load profiles for typical summer and winter days are established and evaluated.

Any periods of lower load (e.g. weekends compared to weekdays, maintenance shutdowns) that may materially impact the cogeneration sizing or operation are considered and their impact evaluated.

The analysis of the load profiles, in particular minimum loads, will determine an indicative size range for the cogeneration plant that will achieve a high level of utilisation of the electricity generated and the heating or cooling produced.

Cogeneration plant configuration

Based on the size range selected by analysis of load profiles, several plant configuration options may be considered. The cogeneration options are chosen based on research and may include:

- various technologies – gas engine, gas turbine, microturbine, fuel cell
- single or multiple units
- a range of output ratings.

The cogeneration plant configuration is outlined in sufficient detail to provide the basis for a concept design and to allow costing of the project.

The following information for each engine selected should also be provided:

- type of generator, nominal kW_e rating and voltage
- natural gas fuel supply
- point(s) of electrical connection
- fuel compressors (if applicable)
- electrical switchgear
- heat recovery air-cooled radiator
- weatherproof acoustic enclosure (if applicable).

For a trigeneration unit the following additional components are outlined:

- absorption chiller, nominal kW_t rating
- form of heat input – hot water, steam, direct exhaust gas or multi-energy
- single stage or two stage
- cooling tower.

The performance of the plant should be specified including:

- gross electrical output
- auxiliary load and losses
- gross heat rate HHV basis
- part-load heat rate
- altitude and temperature output de-rating
- performance degradation over lifetime
- NO_X emissions
- heat output and conditions (steam, hot water, exhaust gas)
- absorption chiller output and conditions
- absorption chiller COP
- absorption chiller auxiliary load
- absorption chiller cooling load.

The location of the cogeneration main plant (generator set, switchgear, step-up transformer if required, heat recovery plant, absorption chiller) and any balance of plant (water pumps, air-cooled radiators, cooling towers) should be established and a layout drawing provided. The proposed routing of any associated hot water, steam, chilled water and feed water piping should be indicated on the layout drawing.

An outline of the foundation requirements for the cogeneration main plant based on the dimensions and mass should be provided.

The manner of connection to interfaces with existing plant should be defined including:

- natural gas supply – point of connection, pressure, pipe diameter
- electrical connection – point of connection, modifications to existing switchboard(s), marked-up electrical single line diagram, step-up transformer if applicable, circuit breaker rating, cable rating and size, protection systems
- hot water supply and return – point of connection, temperature, mass flow rate, pipe diameter
- steam supply – point of connection, pressure, temperature, pipe diameter
- condensate return and feedwater – point of connection, temperature, percentage returned, pipe diameter
- steam boiler blowdown – point of discharge, frequency, mass flow rate, temperature, pipe diameter.

The control philosophy of the plant is outlined in terms of:

- grid interface
- protection systems
- interface with existing boilers (cogeneration applications)
- interface with existing chillers (trigeneration applications)
- response to load changes.

Capital and operating costs

The capital costs for each cogeneration option are estimated including:

- equipment supply and delivery
- civil, electrical and mechanical installation
- commissioning and testing
- contingency
- escalation

- owner's costs – financing, legal, environmental, project management, engineer, connection agreement.

The electrical installation costs will incorporate any modifications or upgrades to existing electrical infrastructure to accommodate connection of the cogeneration.

Similarly, mechanical installation costs will incorporate any modifications or upgrades to existing natural gas supply infrastructure to accommodate connection of the cogeneration.

The capital costs for trigeneration will also incorporate the cooling tower, which is likely to be remote from the absorption chiller, including electrical supply and interconnecting water pipework. In many instances cooling towers are already in operation and utilising excess capacity can be appropriate. This should be analysed before a new tower is planned and costed.

The operating costs for each cogeneration or trigeneration option are estimated including:

- operating labour (if applicable)
- scheduled maintenance
- reasonable allowance for breakdowns
- balance of plant maintenance
- chemicals
- lubricants
- consumables
- water (makeup for steam boilers, makeup for cooling towers)
- stand-by electricity
- insurance.

Energy and greenhouse gas savings

The energy use (electricity and natural gas) of the facility is calculated without cogeneration or trigeneration and with cogeneration or trigeneration, to determine the facility energy savings.

The GHG emissions of the facility are calculated for cogeneration or trigeneration and without cogeneration or trigeneration to determine the facility GHG savings.

Financial appraisal

A financial appraisal of the proposed cogeneration project is undertaken by comparing the energy costs of conventional supply (grid electricity, gas fired boiler, electric chiller) with the cogeneration project capital costs and operating costs (fuel plus operation and maintenance) using a discounted cash flow analysis (refer section 4).

The financial appraisal should provide a base case and sensitivity analysis conducted to test the impact of changing key input variables such as:

- capital cost
- electricity tariffs
- natural gas tariffs
- waste heat utilisation
- maintenance costs
- operating hours.

Appendix 7: Green ratings

NABERS

The NABERS rating scheme evaluates environmental performance of existing buildings on a 1–6 star scale. A six star rating represents market-leading environmental performance, while a one-star rating indicates poor performance and opportunities for improvement. Accredited NABERS ratings are available for offices, hotels and shopping centres. NABERS ratings for offices include energy, water, waste and indoor environment.

October 2012 NABERS National Steering Committee Ruling on Co/trigeneration

In October 2012, the NABERS National Steering Committee revised the rules for the treatment of cogeneration and trigeneration within a NABERS energy rating. The NABERS National Steering Committee decision followed a period of extensive public consultation and an in-depth industry review.

Key outcomes of the October 2012 decision are as follows:

1. NABERS will now recognise low-emissions electricity that is generated off site. This means that if you buy electricity from a precinct or district (or otherwise external) co/trigeneration supplier it will now count towards your NABERS energy star rating
2. NABERS will continue to report transparently on both the energy efficiency and emissions intensity of buildings. As with Green Power, those who decide to purchase low-emissions electricity will receive recognition of this on their NABERS rating certificate. The rating certificate will also show the energy efficiency of the building by displaying what the star rating would have been without the purchase of low emissions electricity
3. Thermal energy that has been exported between buildings will be recognised. If you receive water heating and/or cooling services (thermal energy) from a cogeneration or trigeneration plant that is external to the building, this will also be included in a NABERS energy rating
4. An industry working group will be initiated to develop an accreditation standard for low emissions electricity
5. Tenants in buildings which purchase electricity from an on-site cogeneration or trigeneration plant will now have this identified on their NABERS energy tenancy rating certificates as low emissions electricity.

For more information on the October 2012 NABERS National Steering Committee Decision please refer to the NABERS website **www.nabers.gov.au**.

Onsite cogeneration systems

Where the cogeneration or trigeneration plant is within the boundaries of a building, the NABERS rating will be based on the gas input used by the building's cogeneration plant.

Installing a cogeneration or trigeneration system in a building is a considerable investment to reduce the environmental impact of the building.

The building will purchase gas to operate its cogeneration or trigeneration system which offsets the need to purchase grid electricity. The NABERS rating will take into consideration how much gas has been purchased and generally the NABERS rating will be improved as gas produces less CO_2e.

The building will also be more energy efficient, because cogeneration and trigeneration systems produce both electricity and thermal energy. When this thermal energy is used to operate the building, the efficiency of the system increases, further reducing the need to purchase external energy which again will improve the NABERS energy rating.

Onsite thermal energy – waste heat

From October 2012, NABERS will attribute GHG emissions to the thermal outputs of a cogeneration system, if it is used within the building where the cogeneration system is installed or imported from an off-site system; Thermal energy will now be included in a NABERS energy rating. An example is given in Figure 51.

At this time, there is no agreed industry standard for allocating GHG emissions to the energy generated by cogeneration or trigeneration systems. To address this issue an industry led working group has been formed to develop a suitable standard. To allow building to continue to be rated whilst the standard is being developed NABERS will assess rating on a case-by-case basis.

A well-designed onsite cogeneration system will have a positive impact on that building's NABERS energy rating, due to reduced emissions and increased efficiencies.

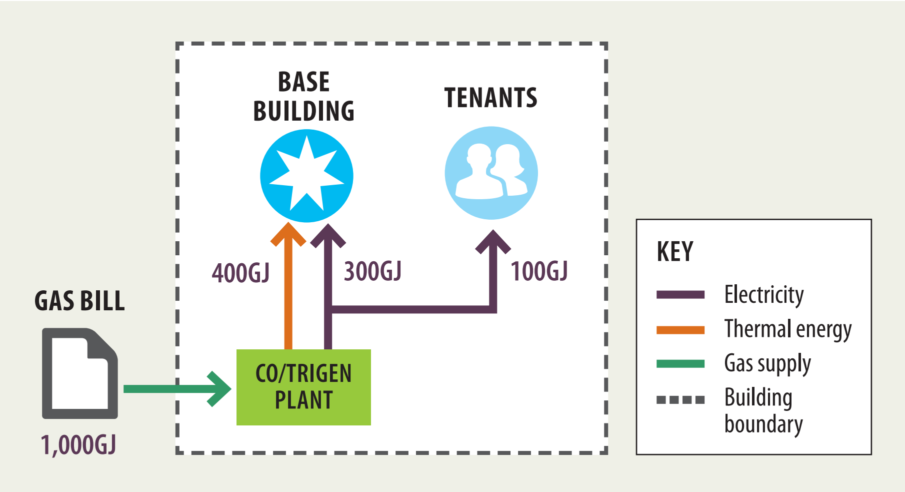


Figure 51: Example potential split of thermal energy and electricity in a commercial building

Generally, a well-designed on-site cogeneration system will have a positive impact on that building's NABERS energy rating, due to reduced emissions and increased efficiencies.

Offsite/district cogeneration

Information regarding the treatment of offsite or district cogeneration or trigeneration systems within a NABERS energy rating, including fact sheets and FAQs can be found on the NABERS website: **www.nabers.gov.au**.

All enquiries may be directed to the National Administrator by email: **nabers@environment.nsw.gov.au** or telephone: 02 9995 5000.

Green Star

Green Star is a comprehensive, national, voluntary environmental rating system that evaluates the environmental design and construction of buildings and communities.

A cogeneration system is rewarded with the following three credits with the Green Star suite of tools:

- greenhouse gas emissions – a cogeneration plant can help in significantly lowering a building's predicted GHG emissions
- peak energy demand reduction – a cogeneration plant can actively reduce the peak demand load on electricity infrastructure
- shared energy systems: This credit encourages and recognises the use of shared energy stations that minimise maintenance, energy and resource consumption. A shared cogeneration system can result in a higher utilisation of the plant when shared between two sites. A shared system can increase economic or logistic feasibility of the plant and can help overcome site constraints such as space or fuel availability issues.

Using the above credits, a cogeneration or trigeneration system can enhance Green Star rating by one star, depending on the configuration and application of the system.

For more information, see the publications and website of the Green Building Council of Australia: www.gbca.org.au/green-star/green-star-overview/

Appendix 8: Useful resources and links

Useful resources

Cogeneration Frequently Asked Questions for Business: Sustainability Victoria
www.sustainability.vic.gov.au/resources/documents/cogeneration_faq.pdf

Unlocking the Barriers to Cogeneration: Climateworks Australia
www.climateworksaustralia.org/sites/default/files/documents/publications/climateworks_unlocking_barriers_to_cogeneration_report_sept2011.pdf

Renewable energy project analysis tool (RETScreen): Natural Resources Canada
www.retscreen.net/ang/home.php

NSW Office of Environment & Heritage, Energy Efficiency Business
www.environment.nsw.gov.au/sustainbus/

Federal Energy Efficiency exchange:
eex.gov.au/

Introducing Combined Heat and Power: Carbon Trust UK
www.carbontrust.com/media/19529/ctv044_introducing_combined_heat_and_power.pdf

Embedded Generation Connection Guide : Clean Energy Council Australia
www.cleanenergycouncil.org.au/

Glossary

Term	Meaning
AEMC	Australian Energy Market Commission. Rule maker and developer for the nation's energy markets
AEMO	The Australian Energy Market Operator (AEMO) functions include implementing, administering and operating the wholesale exchange and managing the security of power system.
Auxiliary load	The amount of taken energy from an engine in order to enhance the engine's ability to create more energy. Also known as parasitic loads, e.g. oil pump being used to lubricate the engine.
CAPER	Protection of the Environment Operations (Clean Air) Regulation
CHP	Combined heat and power is a synonym for cogeneration. The simultaneous production of electricity and useful heat from a single fuel source
COP	Coefficient of performance. Amount of useful work (energy) out from energy in
Cogeneration	The simultaneous production of electricity and useful heat from a single fuel source
DLF	Distribution loss factor. Amount of loss through the transport of electricity
DNSP	Distribution network service provider. Organisation responsible for the distribution and transmission of electricity. In NSW, the three DNSPs are Ausgrid, Essential Energy and Endeavour Energy
ECM	Energy conservation measure
EIS	Environmental impact statement
Electricity loads	Amount of required electrical energy for system (or equipment) to perform task. For example, amount of energy required for a motor to run a conveyor
Engine turn down	Level of capacity that an engine can run before it shuts down
Enthalpy	Enthalpy is a measure of the total energy of a thermodynamic system
EPIs	Environmental planning instruments
ESS	NSW Energy Saving Scheme. A market-based financial incentive scheme for implementing energy efficiency projects
Fault levels	The current expected to flow into a short circuit at a stated point on a system
GHG	Greenhouse gas emissions
Green Star	Voluntary environmental rating system that evaluates the environmental design and construction of buildings and communities.
HHV	High heating value. A value given to heat which includes the latent heat of condensation of any combustion water vapour
High grade heat	high/low pressure steam, hot water above 100°C, generally easier to get useful work out of high grade heat
Interval Data	Fifteen minute or 30 minute energy consumption data collected by energy suppliers.
kWe	Kilowatt of electrical energy
kWt	Kilowatt of thermal energy
kWr	Kilowatt of refrigeration energy
Load	Amount of required energy for system (or equipment) to perform task e.g. the amount of energy required for a motor to run a conveyor

Term	Meaning
Load factor	Capacity of generation compared to load requirements
LHV	Low heating value. A value given to heat that does not include latent heat of condensation of any combustion water vapour
Low grade heat	lower temperature – generally under 100ºC
M&V	Measurement and verification. Framework used to measure and verify energy and or cost savings
NABERS	National Australian Built Environment Rating System –rates the environmental performance of existing buildings on a 1–6 star scale.
NER	National Electricity Rules. These rules govern the operation of the national electricity market. The Rules have the force of law, and are made under the National Electricity Law
NEM	The national electricity market (NEM) is a wholesale exchange for electricity for the Commonwealth adjacent areas and those states and territories that are electrically connected - Queensland, New South Wales, Australian Capital Territory, Victoria, South Australia and Tasmania
ORC	Organic Rankine cycle. A type of cogeneration system set up.
Prime mover	The equipment which drives the electrical generator and produces the heat by-product, e.g. engine or turbine.
Sankey diagram	Type of diagram to show inputs and outputs in a visual way.
Spark spread	The difference between the cost of purchasing electricity (including all network and environmental charges) to that of purchasing alternative fuel such as natural gas to generate your own electricity
Thermal loads	Amount of required thermal energy for a system (or equipment) to perform a task, e.g. the amount of steam needed in the sterilisers.
Thermal utilisation	The use of waste heat generated from the cogeneration system to drive other process. This is critical if efficiency gains are to be made. Thermal utilisation is the amount of waste heat captured from a cogeneration system and put to use in other process, such as providing hot water or space heating. High thermal utilisation is critical to improving efficiencies and achieving the best outcomes.
TLF	Transmission loss factor. Amount of loss through the Transmission of electricity
Trigeneration	Produces electricity, heating, and cooling from a single fuel source.
Turn down ratio	The minimum level of output a prime mover can supply in relation to its full capacity.
VSD	Variable speed drive
Waste heat	The heat produced in generation of electricity.

Table of figures

Index