Cogeneration
Frequently Asked Questions for business

Gas fired cogeneration demonstrates an attractive case to businesses that are seeking an energy solution that is both secure and has the potential to protect from rising energy costs.

This fact sheet briefly details answers to Frequently Asked Questions (FAQs) from businesses providing cogeneration projects, and is intended for small to mid-size cogeneration projects (<10 MW electricity).

Q1: What is the typical financial payback for cogeneration projects?

A: The return on investment of viable cogeneration units will most likely be five to ten years.

The economics of cogeneration are largely driven by the relative advantage of generating electricity and the useful source of heat rather than depending on electricity from the grid. Cogeneration is directly related to, and highly dependent on, the fuel and electricity tariffs which are applicable to the site.

In reality, you should not pre-empt likely paybacks without doing a pre-feasibility assessment which includes a dynamic energy balance and reasonable estimates for determination of costs; for example, electrical connection issues and costs, waste heat boilers and auxiliary equipment and site integration issues (control and monitoring costs).

Sustainability Victoria cogeneration projects

Project type/sector	$m/MW	Payback period	Status	Comment
Swimming pool	1.7	7 years	Implementation expected in 09/10	Build, Own, Operate cogeneration unit by a third party & Transfer and sale of electricity and hotwater by a third party to the customer (BOOT)
Manufacturing	1.0	8 years	Installed	Existing infrastructure used to reduce capital outlay
Precinct development	3.3	6 to 9 years	Planning	Units are 100-400 kW
Designed to maximise the use of waste heat				
Manufacturing	1.8	9.8 years	Did not proceed	Payback period outside commercial return for investment
Food and beverage	1.6	10 years	Installed	BOOT
Manufacturing	3.8	Over 13 years	Did not proceed	Payback period outside commercial return for investment
Housing development	1.8	13 years	Did not proceed	Underestimated the high augmentation and connection costs

Q2: What is the typical financial cost for cogeneration projects?

A: The overall cost of a cogeneration project varies significantly depending on the required plant configuration and intended physical location of the plant. Other factors that can significantly impact these costs include:

> the electrical system interconnection (interlocks, protection and safety systems) that includes connection to the grid (to pay the local distribution business)

> the gas supply systems, including mains extensions, supply pressure requirements and associated gas safety systems

> the 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.

The prevailing exchange rate can significantly impact on the total project costs, as the engine/turbine and generation plant is generally imported.

Q3: What price am I likely to receive from exported electricity?

A: If the co-generator is a non-scheduled generator (<30 MW) it will normally be required to negotiate with a retailer point to purchase the entire export electricity from the plant. Again, the retailer will provide pricing based on wholesale value of the energy component only, rather than the total delivered price including transmission and distribution charges that the plant normally pays for power.

These contracts can be structured in various ways (for example, pool value pass through or guaranteed fixed price) but regardless will be structured to cover the retailer's risk in delivering the buy back price to the co-generator.

Q4: What contract term am I likely to get for purchased gas and exported electricity?

A: Typical gas and electricity contracts are normally about up to three years. While the life of a cogeneration unit is about 20 years, this contractual term can lead to a financial uncertainty of the energy costs for the life of the project.

This situation is due to the uncertainty of the future value of electricity and natural gas. Electricity generators and gas producers are uncertain as to the future impacts of carbon and the value of the various energy forms, so are reluctant to enter into firm pricing for longer periods with retailers.

It is fair to say that this forward price uncertainty is probably the greatest impediment to the effective implementation of distributed cogeneration systems.

One option to overcome this is to develop an agreement that provides price certainty for a fixed period followed by a period where the electricity price is linked to the prevailing market value of the cogeneration supply fuel (for example, natural gas) at that time. Whilst this approach does not totally mitigate the risk, it often provides a mechanism to progress the project.

Sustainability Victoria-supported projects that have been implemented have all undergone non-standard commercial negotiations to arrange long-term gas and electricity contracts.

Q5: Can cogeneration reduce my electrical maximum demand?

A: In most cases the network maximum demand charge cannot be reduced when the cogeneration system is installed. Normally, if the end-use site is on a demand-based (kVA or kW) network tariff, it is charged a 'capacity' charge based on the previous highest load demand recorded over the previous year (depending on the network area, this demand is based on the peak energy consumed over any 15 or 30-minute integration period).

This means that in order to reduce the demand level, the cogeneration plant would be required to operate continuously at 100% availability whilst the end-use plant is operating. Whilst reliability and availability of cogeneration plants is normally good, they do occasionally trip and also need scheduled maintenance. During these times, the plant will draw its power requirements from the grid, thus setting the high network demand over the short 15- or 30-minute recording period.

Cogeneration developers are encouraged to discuss flexible options (non-standard agreements) with the Distribution Network Service Provider (DNSP); however, as their tariffs are regulated, they are not obliged to offer flexibility in these tariff options.

Retail and network energy consumption charges may typically account for up to 65%, demand charges may account for up to 30% and fixed charges up to 5% of your total electricity bill. Cogeneration will only reduce the retail and network energy consumption charges and not the demand charges unless a separate agreement is made with the DNSP by your retailer.

A reason why a DNSP has a demand charge is to reserve capacity on the network for your site.

Q6: Should my business plan for cogeneration be based around electricity demand or thermal (heat) demand?

A: Cogeneration can be a solution if the waste heat generated from the plant can be effectively utilised. Careful evaluation of the electrical and thermal load at the site needs to be undertaken prior to proceeding to a pre-feasibility study for cogeneration schemes; for example, 1 MW electrical output cogenerator will also provide approximately 2.5 MW thermal output.

The purpose of cogeneration is to produce electricity and heat together more cheaply than the alternative of producing them separately. The relative amounts of electricity and heat produced can be tailored to the site requirements. Some cogeneration plants produce mainly heat with little electricity output, while others generate large quantities of electricity with little heat. The choice of cogeneration type will depend on the project site requirements.

In most cases cogeneration projects in which Sustainability Victoria has been involved, were not financially viable if the waste heat was not used.

Q7: What is involved in gaining approval for grid connection?

A: Connection to the electricity grid is not simple; the solution is complex, as illustrated below:

A cogeneration unit is a generating unit connected within a distribution network and not having direct access to the transmission network. This means that you require approval from the DNSP to connect to the grid. Various physical and contractual arrangements must be in place before a generation scheme can be connected to a DNSP's network. There are physical arrangements and operating protocols that need to be met by the DNSP to meet their obligation of safety and reliability of supply; for example, electrical infrastructure such as cables, overhead lines, switchgear, civil works and addressing systems fault levels.

The generator may be directly connected to the DNSP's network or indirectly connected via a privately owned network. It may export power into the DNSP's network or just offset (reduce) part of a customer's large on-site demand. In all of these cases, the generator operates in parallel with the network supply, so both the developer and operator must comply with the statutory requirements applying to co-generator or embedded generators.

Depending on the design of the system, the connection of a cogeneration project to the local distribution network normally involves detailed negotiations and agreements between the cogeneration project developer and the DNSP. The connection process is more likely to be successful if both parties can communicate effectively on each other's requirements. The cogeneration developer should move early to establish and maintain clear lines of communication with the appropriate personnel in the DNSP. This business is responsible for planning the development of the network and for engineering new connections.

A connection and other appropriate agreements between the developer and the DNSP must be negotiated and signed. This is a requirement for all embedded generation schemes; and any required connection infrastructure must be installed, tested, inspected, signed off and commissioned.

Connection costs can have a major impact on the financial viability of embedded generation projects. These costs are project-specific, depending on various characteristics of the generation scheme and the local distribution network. The location of the scheme, connection voltage and export capacity will all impact on the connection cost. Developers should recognise that it can take a significant time to get a connection built. One of the major issues involved with the construction of the connection infrastructure is the time required to obtain planning and environmental approvals, as well as the associated lead times for materials and items of plant that need to be ordered, and timescales for installation and commissioning.

Given the crucial nature of these connection approvals to the viability of a cogeneration project it is important to conduct an independent connection study. This will ensure that both the contractual and technical proposals presented by the distribution company are optimised solutions. It also provides the developer with sufficient information to argue its case in the event that agreement is not reached with the DNSP and arbitration is subsequently required.

Q8: Can a cogeneration unit operate without connection to the grid?

A: Islanding (that is, the ability to operate the cogeneration plant in total isolation from the electricity grid) is a feature that many customers would find attractive; however, it is often technically complex to deliver.

To effectively implement islanding, the cogeneration plant has to be designed to rapidly respond to load demand, meet voltage and frequency requirements and sustain generation plant stability. These requirements are different from the normal arrangements that would call for the co-generator to disconnect when substation supply is lost. The stability of the cogeneration plant requires complex control systems to quickly reduce the plant output during the transition to islanded operation.

An alternative to the islanding option is partial islanding. In this case, a 'non-critical' section of the plant is isolated from the main system with the supply for this section provided by a dedicated generator. As this system is electrically isolated from the remainder of the internal reticulation system as well as the distribution system, the complex protection and control systems are therefore not required. The obvious disadvantage with this approach is that the supply to this area relies completely on the reliability of the cogeneration system, as there is no backup support from the mains supply. These standalone type systems also need to have synchronous generators and black start capability, as they need self-excitation capability for system restarts.

Q9: Will cogeneration save the distributor money?

A: Cogeneration plants whose output is traded through the National Electricity Market (NEM) are referred to as 'market generators'. All cogeneration plants that choose to use the wholesale market to buy and sell their electricity must be registered as market generators with Australian Energy Market Operator (AEMO), formerly NEMMCO. In addition, if the cogenerating plant has a nameplate rating of 30 MW or greater, the generator is normally classified as a scheduled generating unit with its output despatched by the AEMO.

A cogenerating plant with less than 30 MW and will not export less than 2-GWh in any 12 month period. will not normally have its output despatched by the AEMO System Operator.

Generators that negotiate with a retailer or a customer located at the same connection point to purchase the entire export electricity from the plant must be registered as 'non-market generators'. The same rules apply as for market generators to determine whether the generating plant will be classified as 'scheduled' or 'non-scheduled'. Depending on the nature of the Power Purchase Agreement negotiated with the retailer, non-market generators may benefit by not having to pay the fees applicable to settlement through the market.

A cogeneration plant, whether scheduled or non-scheduled, can provide significant benefits to the DNSP. By incorporating these distributed generation sources the outcome can yield a greater amount of flexibility and improved performance for their network.

The growth of distributed generation has led to a situation in which the distribution networks are evolving from passive networks to systems that are required to actively respond to the dynamics of the main grid. This is often a challenge to these distribution companies, as the network no longer behaves as it did prior to inputs via distributed power sources. Consequently, its planning and operation must be approached somewhat differently, and with a greater amount of care and diligence.

Glossary

Term	Meaning
Black start	This is an ancillary service which enables the grid to recover from a total shutdown
BOOT	Build, Own, Operate cogeneration unit by a third party & Transfer and sale of electricity and steam by a third party to the customer
Distributor or distribution company (DNSP)	The company in your region which owns and ensures the maintenance of the electricity network (poles and wires plus other associated infrastructure)
Embedded generator	A generator that is connected to a local network rather than directly to the grid
Islanding	The generator is not connected to the electricity grid and power produced is used in house and not exported to the grid
Market generators	Sell entire electricity output through the spot market and receive the spot price at settlement
Maximum demand	The rate at which electricity is consumed continuously, averaged over a 15- or 30-minute interval
NEMMCO	National Electricity Market Management Company. Now called Australian Energy Market Operator
Non-scheduled	Aggregate generation capacity of less than 30 MW or specifically classified as non-scheduled due to intermittent nature of generation
Scheduled	Aggregate generation capacity of more than 30 MW
Synchronous generator	An AC generator in which the average rotational speed of the rotor in normal operation is exactly proportional to the system frequency

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