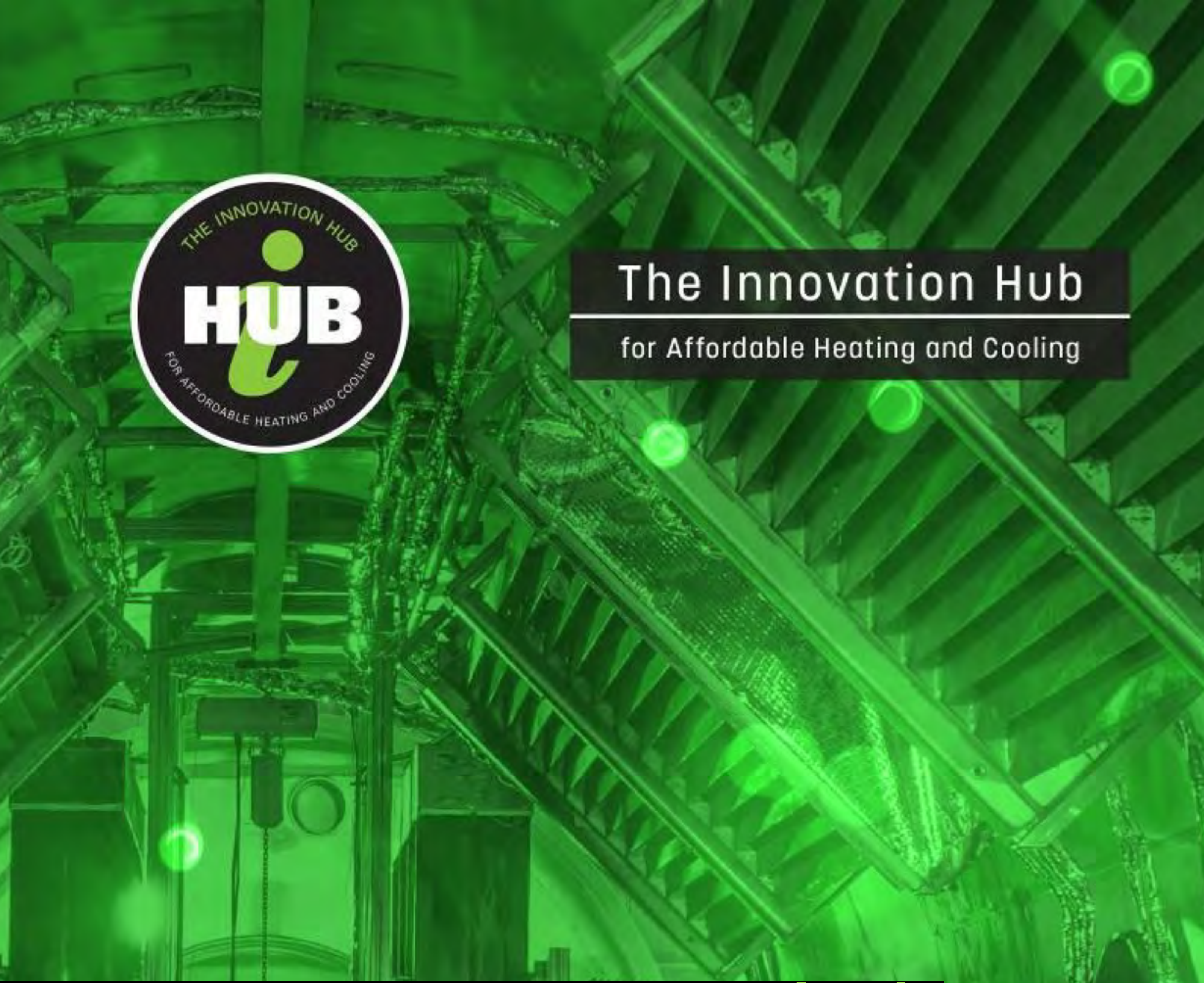


**Sub-Project Final Knowledge Sharing Report – DCH3**

# Precinct energy integration for accessing the wholesale demand response mechanism

DCH3

June, 2022

**DeltaQ**

## About i-Hub

The Innovation Hub for Affordable Heating and Cooling (i-Hub) is an initiative led by the Australian Institute of Refrigeration, Air Conditioning and Heating (AIRAH) in conjunction with CSIRO, Queensland University of Technology (QUT), the University of Melbourne and the University of Wollongong and supported by Australian Renewable Energy Agency (ARENA) to facilitate the heating, ventilation, air conditioning and refrigeration (HVAC&R) industry's transition to a low emissions future, stimulate jobs growth, and showcase HVAC&R innovation in buildings.

The objective of i-Hub is to support the broader HVAC&R industry with knowledge dissemination, skills-development and capacity-building. By facilitating a collaborative approach to innovation, i-Hub brings together leading universities, researchers, consultants, building owners and equipment manufacturers to create a connected research and development community in Australia.

**This Project received funding from ARENA as part of ARENA's Advancing Renewables Program.**
**The views expressed herein are not necessarily the views of the Australian Government, and the Australian Government does not accept responsibility for any information or advice contained herein.**



## Precinct Energy Integration for Accessing the Wholesale Demand Response Mechanism

The project assesses the feasibility of using potentially significant resource of existing, under-utilised gas-fired generators to assist in managing the site and grid level impacts of the variability of renewable generation. It seeks to understand how existing gas-fired generation assets can operate in sync with on-site energy consumption and renewable generation to maximise life-cycle and environmental benefits while also providing useful support service to the grid.

The project used Collins Square, an office precinct in Melbourne CBD, as a case study and testbed. The precinct offered an excellent environment to analyse real data from multiple in-use office building, with an operational gas-fired generation and renewable energy generation capabilities.

The i-HUB/CSIRO developed Data Clearing House, provided the opportunity to integrate diverse data sources across multiple buildings and discrete systems, which enables whole-of-precinct optimisation to be undertaken.

This project delivered the following:

- Business case assessment of using existing gas engines as a demand response resource
- Strategies and algorithms to achieve successful demand response operation in conjunction with HVAC and on-site PV generation
- Guidelines to assist other sites achieve demand response operation.

### Lead organisation

DeltaQ Pty Ltd

### Project commencement date

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### Completion date

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https://www.ihub.org.au/dch3-precinct-energy-integration-for-accessing-the-wholesale-demand-response-mechanism/

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# 1 INTRODUCTION

## 1.1 Sub-Project Objectives

Cogeneration and trigeneration plants in buildings convert a fuel source (most commonly natural gas) to electricity, with the waste heat typically being used for space heating (cogeneration) and absorption chiller cooling (trigeneration). The generic layout of the cogeneration and trigeneration systems is shown in Figure 1. The two most-common generator types that have been installed in commercial buildings are reciprocating engines and microturbines (1,2). The type and size of generators available vary, along with the maximum design ramp rates (i.e. speed to load or unload) and electrical efficiencies.

In the period 2000-2015, many office building developments installed cogeneration or trigeneration systems to reduce the use of carbon-intensive grid electricity. However, many of these systems have ended up mothballed or under-utilised because of increasing gas prices and poor matching of the generator size to site load characteristics; furthermore, over the next decade the grid is expected to decarbonise to the point where these systems no longer provide an emissions benefit. Consequently, there is an opportunity to determine if these high-embodied energy assets can be utilised in ways where they can create a net benefit – both financially and environmentally – rather than being decommissioned.

Since 2015, the quantity of renewable energy generation in the electricity grid has increased significantly, and many buildings have also installed on-site PV arrays, sometimes of significant capacity. While this reduces carbon intensity, it also increases the level of instability in the site energy consumption - due to variations in on-site generation – and in the electricity grid more generally. These factors combine to create an increased requirement at both site and grid level for the ability to provide demand response to smooth out renewable energy induced variability.

This project explores the option of using under-utilised gas generators for cogeneration and trigeneration systems as demand response units. The findings are intended to inform if and how these generators can be operated to complement on-site and grid-connected renewable energy generation, support the electricity grid stability, and thereby facilitate the maximisation amount of renewable energy generation overall.

The primary objectives for this project are to:

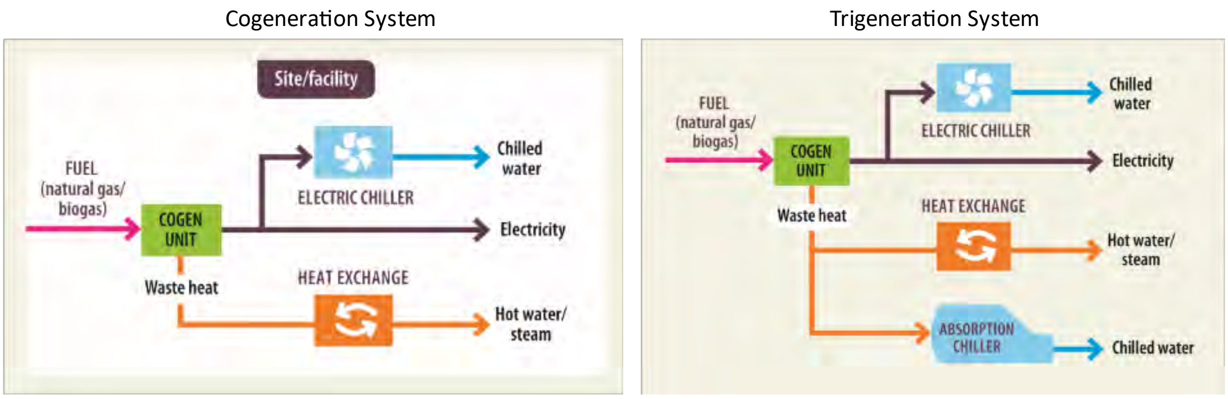


*Figure 1: Cogeneration and Trigeneration System (reproduced from (1))*

- Develop a strategy for operating existing under-utilised cogeneration/trigeneration gas engines as demand response units in response to short-term changes in on-site renewable generation output and to demand response events in the electricity market
- Analyse the business case for such operation.
- Provide guidelines and information to assist other similar sites to achieve similar outcomes.

### 1.2 Boundaries and Limitations

This project focuses on gas-fired generators that have been installed as part of cogeneration or trigeneration systems in commercial buildings. It is limited to the case where the gas generators are used solely for the purpose of demand management rather than generators that are currently operated to supply a site's base load. The rationale for setting this limitation is in part due to the current environment where gas costs do not necessarily favour on-site cogeneration and trigeneration, and in part due to the growing number of commercial building sites looking to decommission their cogeneration and trigeneration systems. Furthermore, the capacity available from using the generators for demand response is greater if they are not being used to supply base load.

This analysis assumes that there are no changes to the site's operation during the demand response events; i.e. all other aspects of the building's operations are unchanged; thereby ensuring that the change in the site's grid electricity demand is solely based on substituting a portion of grid electricity consumption with electricity generated by the generator.

### 1.3 Methodology Overview

The project's objectives have been met by using the following approach:

- Investigation of how building owners can participate in wholesale demand response mechanism. This encompassed consultation with demand response service providers and electricity market participants.
- Analysis of building data from a pilot site that has both trigeneration and PV generation capabilities. The building data was onboarded onto the Data Clearing House. The investigation was further supported by data from the National Electricity Market and the information obtained from energy retailers and demand response service providers.
- Development of a Building Owners' Guide to help building owners determine if the use of gas-fired generation should be further considered in their case. The guide includes strategies to estimate the financial and environmental impact of using the gas-fired generators to respond to demand at a site level and to events in the grid.

The following two scenarios were considered:

1. Using generators to respond to short-term changes in on-site renewable generation output (site-level),
2. Using generators to respond to events in the grid (Reliability and Emergency Reserve Trader (RERT) events and participation via the wholesale demand response mechanism (WDRM))

## 2 BACKGROUND AND IMPACT

### 2.1 Cogeneration/trigeneration Installed and Potential Demand Response Capacity

The installation of cogeneration and trigeneration units in commercial buildings (and other locations such as recreation and aquatic centres) peaked between 2010 - 2015. However, the extent of existing operable gas generators in the market is not well documented. A review conducted as part of this project indicates that at least 120 MW of cogeneration and trigeneration capacity has been installed in the buildings (commercial, office towers, retail and residential), hospitals, and recreational facilities and precincts[1]. In the built environment, the largest generation capacities are likely to be in hospitals, followed by data centres, airports, and office buildings[2]. However, the current statuses of these installations vary widely (Figure 2) and include:

- Currently used regularly to services part of the base building loads
- Operational but used sporadically
- Not currently used. It is unknown whether these can be safely fired up as a demand response unit. It is understood that some of the engines have been dormant for too long, with additional repairs required for it to be operational.
- Has been switched off, decommissioned, or removed (3)[3]

| Operational | Earmarked for decommissioning | Not Operational |
| --- | --- | --- |
| •Systems currently used to support building base loads<br>•Systems that are operating, albeit sopradically (e.g. as not scheduled generation units) | •Systems that are currently operating but earmarked to be decomissioned. | •System Decomissioned<br>•System has not been used in a while and/or requires the additional repairs for it to be operating |

*Figure 2: Operational states of existing cogeneration and trigeneration assets*

Operating the cogeneration or trigeneration system for demand response is limited to gas generators that are currently in an operational state. This is because the financial feasibility of operating such systems only for the purpose of demand response is heavily dependent on the operation and maintenance cost of the system (further details are provided in subsequent sections). Any additional cost incurred to repair currently inoperable generators will likely result in a financially non-beneficial business case.

It is expected that the available capacity of generation from this sub-sector will continue to decline fairly rapidly. As a result, if use is to be made of the remaining generators in demand response, it will require speedy intervention.

### 2.2 Demand Response and Types of Events

Two levels of demand response can be considered:

1. Site electricity demand. The generators from the cogeneration or trigeneration units can be used to minimise peak demand charges arising from building energy use peak demands or from the combination of building demand with sudden fluctuations arising from short-term reductions in on-site PV generation (i.e. when the sun goes behind a cloud).

[1] Based on a compilations of publicly available and confidential sourced information
[2] The installed capacity of cogeneration and trigeneration, for hospitals, data centres, airports and office buildings are at least 50 MW, 38 MW, 29MW identified, and 28MW, respectively.
[3] Based off AEMO's NEM generation list (3).

2. Grid demand events. Grid demand events occur when there is a grid-level shortfall in generation relative to the load, either because of excessive demand or because of short-term deficiencies of generation. There are several different types of grid demand events, as summarised in Table 1.

*Table 1: Types of grid demand events and suitability for gas-fired generators to respond to them.*

| Grid Demand Events | Description | Expected Event Frequency, Duration and Response Time† | Suitability for gas-fired generators |
|---|---|---|---|
| **Reliability and Emergency Reserve Trader (RERT)** | The Reliability and Emergency Reserve Trader events are signalled by a forecasted shortfall in energy reserves, typically when there's a combination of hot/ extreme weather, high demand, generation or transmission outages. RERT events are enacted by AEMO, and are infrequent. | Frequency: Low<br>(1 – 3 times a year)<br>Duration: 3 – 6 hours<br>Response time: <120 mins | Y |
| **Wholesale Demand Response (WDR)** | These are events that are signalled by a spike in the spot price of electricity. These are typically based on the Wholesale Demand Response Mechanism (WDRM). | Frequency: Moderate<br>(5 – 20 times per year)<br>Duration: Variable, depending on settings selected by the demand responder.<br>Response time: < 30 mins | Y |
| **Frequency Control Ancillary Services (FCAS)** | These are events that are signalled by a frequency outside the preferred control range and are fast response events of short duration (10mins or less). | Frequency: High<br>(10-20 times per year)<br>Duration: 10 mins or less<br>Response time: 6 sec, 60 sec, or 5 mins | N* |

**Notes:**
† Frequencies may varies depending on the location (State). Based on a collation of values published and review of market rules and events (4–6).
* Due to these characteristics, they are less well suited for generator response and so are not considered further

For grid events, the demand response is a reduction in the demand that occurs at the connection point to the electricity grid (at the NMI). As the magnitude of demand response cannot be measured directly, it is estimated by comparing the actual load profile with a prediction of what would have occurred if the site did not respond. This predicted load profile, referred to as the baseline, is estimated using the site's historical consumption. For RERT and WDR events, it is based on the consumption from the 10 or 4 most recent qualifying days, depending on the methodology (7,8)[4].

The nature of RERT events and times when Wholesale Demand Response Units have been dispatch can be characterised from electricity market data available to the public. Figure 3(a) provides an overview of the RERT

[4] The exact number of days depends on the methodology used, which is one of AEMO's approved baseline methodology.

events that were activated, showing the start time, which averages at 4pm, and duration. The activation of RERT across in different states on the same day are presented as separately (one per state).

(a)

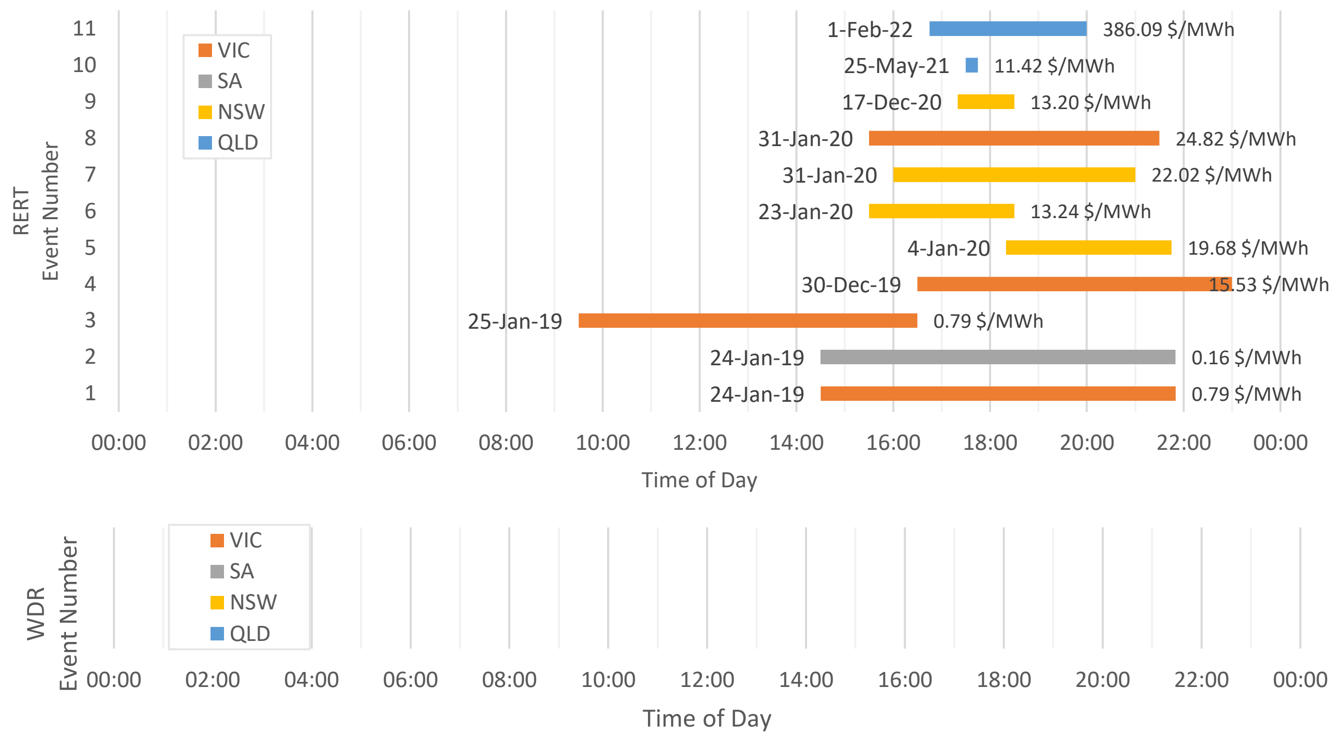


*Figure 3: Summary of time and duration of RERT and WDR events. (a) Summary of RERT events that were activated between January 2019 and March 2022. The event date, start time, end time, and average Total Cost Recovery ($/MWh) as reported by AEMO are shown. (b) Start and end time when WDRU were dispatched in NSW and VIC. (Data Source: AEMO* (9).

Wholesale Demand Response 'event' can also be studied by analysing the times and durations that wholesale demand response units were dispatched. Since October 2021, when the Wholesale Demand Response Mechanism came into effect, until April 2022, wholesale demand response units have been dispatched twice[5]. The start times and end times are shown in Figure 3(b).

## 2.3 Method of Participating in Grid Events

When considering using gas-fired generation to respond to grid-level events, building owners can participate through a third-party service provider that acts as an aggregator to consolidate the response across multiple sites. For sites with a cumulative generator capacity exceeding 1 MW, direct market participation is possible, albeit probably unattractive. Table 2 summarises the differences between direct participation in the market and participation through an aggregator.

[5] This exclude dispatches where the units were being tested as part of the commissioning process.

*Table 2: End-users participation in demand response - directly or through an aggregator.*

| End-User - Direct market participation | Aggregator – Market participation (with many end-users) |
|---|---|
| End-users will need - In-house electricity market and engineering expertise | End-users will not need - In-house electricity market and engineering expertise is provided by Aggregator |
| Require minimum 1 MW of dispatchable load (for the wholesale demand response mechanism) | No/lower minimum requirement for dispatchable load |
| Close control over pricing returns from event | Share pricing returns from event with Aggregator |
| Requires full administration and compliance time/effort | End-users requires limited administration and compliance time/effort |
| Requires engagement with industry and ongoing assessment of the schemes | Aggregator manages the engagement with industry and ongoing assessment of the schemes |
| Requires the installation of compliant equipment such as metering and telemetry (end-user provided) | Requires the installation of compliant equipment such as metering and telemetry (generally the Aggregator will provide) |
| Participation in multiple different types of market events/ mechanisms may require separate market registration and different metering and telemetry requirements. | End-user can participate in different market events/mechanisms through the aggregator |

# 3 Using Gas-Fired Generators as Demand Response Units – Operating Strategy and Impacts

## 3.1 Responding to Short-Term Changes in On-Site Renewable Generation Output

### 3.1.1 Operating Strategy

Gas-fired generators can only realistically be used to respond to short-term changes in on-site renewable generation outputs via the use of the generator in a generalised demand management strategy of which renewable generation variability is just one of several drivers for peak events. Such a strategy would work as follows:

1. A peak demand target is set at the beginning of each new demand charging period.
2. Whenever the monitoring indicates that the target peak demand is at risk, the generator is operated to attempt to maintain the demand just below the target.
3. As the threat of a new peak demand event decreases, the generator output is throttled back to minimum.
4. After generator minimum run time has been reached and the threat of a new peak event has passed, the generator can be turned off.
5. If the demand target was breached, the resultant peak becomes the new demand target for the balance of the demand charging period.

In this project, we have only assessed the potential interactions between short terms drops in on-site renewable generation and gas generator operation. The ability for the gas-fired generators to meet the short-term decrease in renewable energy generation varies depending on the multiple factors:

- The generator's capacity relative the PV array size (which influences the magnitude of the decrease in renewable generation)
- This time taken for the generator to respond: This is the combined time of detecting the change in renewable energy generation, the time taken for the gas generator to start up and ramp up to the targeted

power output. It will therefore depend on the electrical submeter interval timing and response time of the gas generator and associated controls.

Batteries can be integrated into the site's operation to minimise response time but are not necessarily required if the gas generator is sufficiently large relative to the PV array. The need for a battery and its size varies depending on the factors listed above, along with the frequency and time between each event.

On-site batteries can be integrated into the site's operation via the following modes:

- Battery discharges during the initial stages of the event, when the gas-fired generators are starting up and ramping up
- Battery discharges during the middle of the event if the combined output of the generator and on-site renewable generator is insufficient to meet the site's demand.
- Battery charges when the event ends (i.e. on-site renewable energy generation increases), and the gas-fired generator is either awaiting the shut-down signal or ramping down.

From the perspective of minimising peak grid import during the initial stages of the event, it was found that a battery becomes more beneficial once the gas-fired generator capacity falls below 1.7 times the magnitude of the short-term reduction of on-site renewable energy generation. This threshold was based on an assessment that only considered the battery discharging in the initial stages of the event. It assumes that the duration between events is sufficient for the battery to be recharged, and that charging will not create a peak demand event. The cost effectiveness of battery installation was not assessed.

An illustration of the operating strategy is provided in Figure 4.

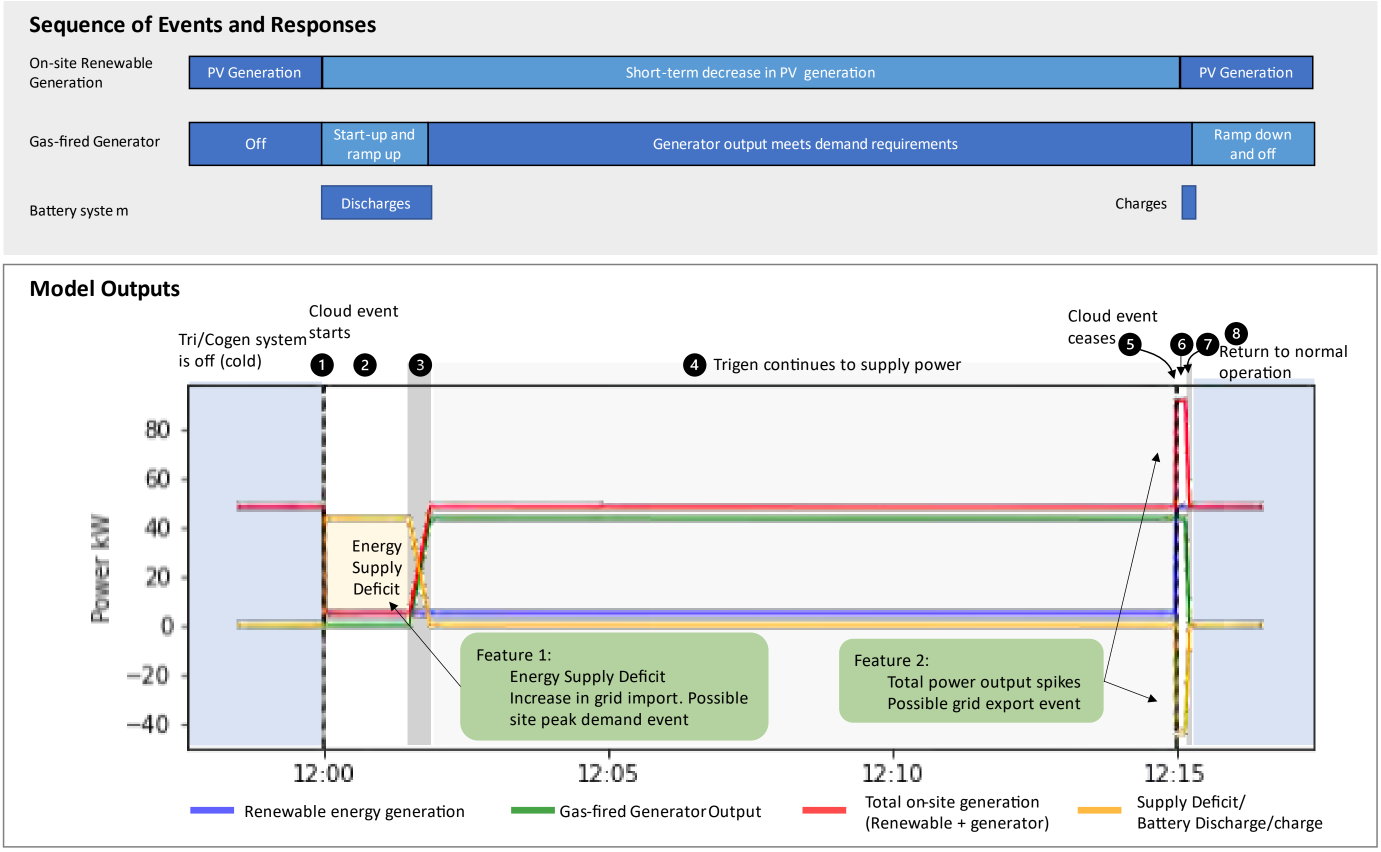


*Figure 4: The sequence of events/operation mode of a gas-fired generator in response to a short-term decrease in on-site renewable generation output. The resulting model outputs is shown (below)*

### 3.1.2 Financial Impact

The financial impact of operating the gas-fired generators in response to short-term changes in on-site renewable energy can be determined by comparing the cost incurred to operate and maintain the cogeneration/trigeneration system and the cost of generator fuel, with the avoided electrical peak demand charges and consumption costs.

Multiple factors that impacted the financial outcome of operating the gas-fired generators in response to short-term changes in on-site renewable energy were identified:

- Primary factors which had the greatest impact were:
  - The operation and maintenance cost of the unit/system ($/kWe, excluding the cost of gas consumption)
  - The magnitude of the peak demand charge ($/kVA), and
  - The magnitude of the avoided peak (kVA) relative to the size of the generator
- Secondary factors included:
  - The efficiency of the generator,
  - The mode of operating the generator units (if the generator output will exceed the short-term decrease in on-site renewable energy demand),
  - Generator fuel cost
  - Frequency and duration of the events,

The overall financial benefit is expected to vary and needs to be evaluated on a site-by-site basis. This is because the magnitude of the factors listed above can vary widely for different sites and scenarios. For example:

- The cost of operating and maintaining the co/trigen system can vary widely. Values between \$15 - \$113 per kWe were identified (1,10)[6]. The cost of operation and maintenance could potentially be reduced to values at the lower end of this range, if the maintenance of the co/trigen heat-recovery system and infrastructure can be avoided.
- Savings associated with the avoided peak demand charges are heavily dependent on the scale of the avoided peak demand. A greater financial benefit can be realised if the magnitude of the avoided peak demand is close to the generator capacity, which therefore maximises the generator capacity utilised. The reason is two-fold: 1) generators have higher efficiencies when operating at full load, compared to part load, and 2) the cost of operating and maintaining the co/trigen system is a fixed cost proportional to the generator size. However, the ability to maximise the generator's capacity is also dependent on the size of the on-site PV array, as well as the nature of the demand events, both of which determine the magnitude of the avoided peak if they are smaller than the generator's capacity. On this basis, it can therefore be inferred that while a reduction in peak demand can be achieved by operating the generator, the magnitude of the peak demand event and hence overall financial benefit is uncertain.
- Changes in fuel cost: the current climate in 2022 has seen a rapid increase in natural gas prices. The cost of gas consumption for building owners at present will depend on their method of purchasing gas (e.g. if it is purchased in advance, if their contracted rates are variable or fixed, and/or if their existing contract with the gas retailer is up for renewal). In this project, only variations in on-site gas consumption prices were analysed, although it is acknowledged that the cost of grid electricity also has an influence on the financial outcome.

As an example, consider a building with co/trigen system that has a 75 kWe generator, with a 35% efficiency, and the co/trigen system costs \$5,635 to operate and maintain annually (i.e. \$75 per kWe[7]). The cost of consuming grid electricity is taken to be 14.16 cents/kWh and cost of gas is \$11.51 per GJ. The event considered is 15-mins long where the solar generation output decreased by 45 kW. If the generator is operated at 74 kW, close to its capacity (i.e. at 99% utilisation/load), the avoided peak is determined to be 38 kVA. Under the assumption that there are five similar events in a month, a peak demand greater than \$12 per kVA per month is required for a net-positive financial outcome to be achieved. The sensitivity of obtaining a net-positive financial benefit to the different parameters is discussed in the following points:

- **Variation 1:** A higher minimum peak demand charge will be required if the co/trigen system's O&M cost is higher. For every \$1 per kWe increase in O&M cost, the minimum peak demand charge needed to balance the cost and savings increases by approximately \$0.14 – 0.16 per kVA. This minimum rate of change required is lower when a larger proportion of the generator is utilised. For example, if the generator continues to respond to 74 kW demand events, an increase in O&M cost by \$10 per kWe (i.e. from \$75 per to \$85 per kWe) will require a higher peak demand charge of \$12.40 per kVA (increase by \$1.40 per kVA) before a financial benefit can be realised.
- **Variations 2 and 3:** If the 75 kWe generator is programmed to operate at a lower output, (say) 43 kW, in response to the same event, the generator will be operating at a load of 58%. Then the magnitude of the avoided peak demand will reduce to 26 kVA. Under the same assumption that there are five 15-min events

[6] This based off O&M costs estimated at 1.5 – 3.1% of the capex cost, and the O&M costs for the pilot study site.
[7] kWe refers to the electrical capacity (kW) of the gas-fired generators.

in a month and the O&M cost is $75 per kWe, a peak demand charge greater than $18 per kVA is required before operating the gas generator is financially beneficial. The minimum peak demand charge will increase by $1.60 (to $19.60) should the O&M cost increase by $10 to $85 per kWe.

- **Variation 4:** The cost of gas also affects the financial outcomes of operating the generators. A four-fold increase in gas prices from $11.51/GJ to $46.04/GJ leads results in a $0.67 per kVA increase in the minimum peak demand charge required for the total cost and savings to even out, regardless of the O&M cost. This sensitivity analysis assumed that the price of electricity consumption (cents/kWh) remained constant.

The analysis shows that the gas generator can be operated for general demand management, including variability of on-site generation. The financial outcome, however, is marginal and sensitive on multiple factors and hence needs to be evaluated on a site-by-site basis. This indicates that a more reliable positive financial outcome would require the capture of revenue streams available from grid demand event response, as discussed in the next section.

## 3.2 Responding to Grid Demand Events

### 3.2.1 Operating Strategy

For building owners looking to use their gas-fired generators to respond to grid demand events, the use of a third party such as a retailer or a demand response aggregator is strongly recommended rather than direct participation as a market-registered participant. This avoids the complexity of becoming a market-registered participant and creates new opportunities by becoming part of a portfolio of demand response: It enables demand response below 1MW to participate and provides a level of flexibility in response not necessarily available as a stand-alone participant.

In general, the mechanics of operating from the perspective of the building owner varies depending on the third party engaged and the type of demand response program. Two types of mechanisms were identified during our review process:

- Mechanism 1 – Manual triggering. The third party contacts the building owner/nominated building contact to inform them of an event. The building owner is responsible for responding to the demand by turning the gas generator on at the start of the event and off at the end of the event. This mechanism is more widely used.

- Mechanism 2 – Automatic triggering. The third party informs the building owner/nominated building contact of an event. The controller installed by the third party automatically adjusts the load/ generator to meet the demand. This mechanism is less widely used.

It should also be noted that in most cases, the third party typically has no visibility of the building's operations and plant loads or requirements.

### 3.2.2 Financial Impact

The financial impact of operating the gas-fired generators in response to grid demand events is influenced by, and sensitive to, multiple variables, including:

- revenue from participating in the events,
- the cost incurred to operate and maintain the cogeneration/trigeneration system,
- savings from avoided costs (grid electricity consumption costs and avoided grid event charges; RERT charges), and
- the cost of generator fuel.

Our analysis found that the two most significant factors were the revenue and the operation and maintenance cost of the cogeneration/trigeneration system.

Revenue models for participating in the grid events were identified in consultation with third parties who provided demand response programs.

**RERT Events:**

RERT events are enacted by AEMO when there is a shortfall in electricity demand. Notification of the possibility of these events is provided notification periods of days to hours, and the events typically last between 3 to 6 hours. Note that if no RERT events are preactivated or activated, then the building owner does not receive any revenue.

For RERT events, the revenue is dependent on:

- The number of RERT pre-activation events
- The number and duration of activated events,
- And the demand response capacity (i.e. the amount by which a site can reduce its demand during a RERT event).

$$Revenue\ from\ event\ preactivation = Preactivation\ Rate\ (\$/MW) \times Capacity\ (MW)\ \times Number\ of\ preactivation\ events$$

$$Revenue\ from\ the\ activated\ event = \ Activation\ Rate\ (\$/MWh) \times Capacity\ (MW) \times Dispatch\ Duration(h)$$

$$Total\ Revenue\ from\ the\ event = \ Revenue\ from\ event\ preactivation + Revenue\ from\ the\ activated\ event$$

During RERT events, end-users incur a market charge based on the amount of electricity consumed from the grid during the RERT event. Consequently, operating the gas generators during a RERT leads to additional savings, through a reduction in the market RERT charge, albeit of second order. The charge ($/kWh) varies depending on the event and is calculated by AEMO for each event to cover the cost of the RERT event.

**Participation via the Wholesale Demand Response Mechanism:**

The wholesale demand response mechanism enables end-user to reduce their grid demand and receive payment based on the demand reduced (relative to a baseline), and the electricity spot/market price. While, in theory, participation can occur at any time, it is expected that participation will most likely occur (or be requested by third parties) when the spot price is high.

The following two different revenue models were identified:

- Revenue based on **Contracted Capacity**: End-users receive an annual payment, regardless of the occurrence of events, based on an agreed demand response capacity. This is the magnitude of demand that the end-user agrees to reduce when called upon. The end-user will also receive an additional payment based on the number and duration of events and a fixed dispatch payment rate ($/MWh). The revenue can be expressed as:

$$Revenue\ from\ WDR\ (Contracted\ Capacity) \\ = Annual\ Capacity\ Rate\ (\$/MW) \times Capacity\ (MW) \\ + Dispatch\ Rate\ (\$/MWh) \times Capacity\ (MW) \times Total\ Annual\ Duration\ (h)$$

In the case where there are no events, the expression above reduces down to:

$$Revenue\ from\ WDR\ = Annual\ Capacity\ Rate\ (\$/MWh) \times Contracted\ Capacity\ (MW)$$

- Revenue based on **Market Price Share:** In this form, end-users receive a portion of the market price at the time the demand response event. Revenue is only received if end-user participates in an event.

$$Revenue\ from\ WDR\ (Market\ Price\ Share) \\ = Spot\ Price\ (\$/MWh) \times Market\ Share\ (\%) \times Demand\ Reduction\ Capacity\ (MW) \\ \times Total\ Annual\ Duration\ (h)$$

The market price share revenue model was found to be less favourable than the Contracted Capacity model, and our analysis reflected that the end-user needs to receive more than $500 per MWh (product of the Spot Price ($/MWh) and Market Share (%)) before there is a chance that a net-positive financial outcome can be realised. The stated price threshold increases when gas prices and the generator O&M cost increase.

**Note on Peak Demand Charges and Peak Demand Management:**

Participating in a demand response event (RERT or WDR) will likely lower the maximum demand for that particular day, compared to the estimated demand if the site did not respond. However, this reduction is unlikely to yield a peak demand savings (or significant savings) because there is no guarantee that a RERT of WDR event will align with the building's monthly or annual peak.

The impact of using gas generators as demand limiters, in the absence of on-site renewable generation capabilities, was not evaluated as part of this project; this style of operation could feasibly generate peak demand savings. However, this mode of operation could lead to a lower RERT/WDR demand baseline[8] for the site and hence reduce the amount of revenue available from these mechanisms if the gas generators are used to limit a site's peak demand on a regular basis, or on days leading up to the grid event.

### 3.3 Environmental Impact

For both types of demand response events (site- and grid-level), the environmental impact of the site can be determined using the same approach; a direct comparison of the emissions intensity of electricity generated by the gas-fired generator with the grid emissions intensity.

Annual grid emissions intensities were obtained from the National Greenhouse Accounts Factors (11), while real-time grid emissions can be determined using publicly available data from AEMO.

The emissions intensity of a gas generator varies depending on the generator's efficiency and its location; the latter occurs as the emissions intensity of gas differs marginally for each state/territory (11).

[8] The baseline used to quantify the demand response is calculated based on the site’s consumption for the previous 10 or 4 equivalent day, depending on the methodology used.

In general, the real-time emission intensity of the grid during demand management events is lower than the annual average. This reduces the probability that the operation of a gas generator generates electricity at a lower emissions intensity than the grid during such events. In general, we found that gas generator operation is likely to be detrimental in terms of real-time emissions. Exceptions to this are for generators in NSW, QLD and VIC, where the generators have an efficiency higher than 30%, 26% and 22%, respectively. At these efficiencies, there is a 50% probability that the generator's emissions intensity is lower than the real-time emission[9].

From a site perspective, the emissions intensity is judged from the perspective of average annual emissions factors which, being higher than the event-specific factors, are generally favourable for the use of the generator. This effect is amplified for NABERS ratings, which are based on lagging indicators of annual emissions intensity. At the site level, emission calculations for reporting and for NABERS ratings are based on annual average emission factors. In 2022, the current state of play is:

- VIC: Gas generator operation is likely to reduce overall site emissions
- QLD, NSW, NT, and WA: Gas generator operation may reduce emissions for generators operating at efficiencies above 23%, 26%, 27%, and 29%, respectively.
- SA and TAS: Gas generator operation will increase emissions

While the real-time emissions impact of gas generator use may be detrimental, this ignores the bigger picture question of the extent to which the availability of demand-side resources enables the market to have a higher proportion of renewable energy use. Comparing the low frequency and short duration of demand response events against the year-round emissions reduction of any incremental addition to renewable generation capacity enabled by the demand management services provided, it would seem likely that the net result is strongly in favour of the use of the generator capacity.

### 3.4 Operation of Heat Recovery During Demand Response Events

In co/trigen systems, the ability to use the waste heat for space heating and cooling (via the absorption chiller in a trigeneration system) is a key advantage over sites with a stand-alone gas generator. The decision to operate the heat recovery components of co/trigen systems during demand response events depends on the following:

- Thermal response time for heat recovery: There is a time delay from when the generators are operational to when the effects of heat recovery are observed.
- Time of day that the event occurs: the event needs to occur when there is heating and/or cooling demand in the building. For commercial office buildings, heating and cooling loads occur during business hours on business days, and the building chillers and boilers/heat pumps are operated between 6 am – 6 pm on business days.
- Demand response event duration: The duration of the event needs to be long enough for the effects of the heat recovery to be realised. At a minimum, the events need to be longer than the time constants associated with the generator fuel input to observe space heating/cooling effects in the building.
- Frequency of demand response events: the occurrence of events suitable for heat recovery operations will need to be high enough for there to be a cumulative positive benefit. Where the frequency is low, the efforts required to operate heat recovery and/or the cumulative effects of the potential benefits are little/ insignificant.

[9] The comparison is based on real-time grid emissions between 1st March 2021 and 30th April 2022.

Based on the considerations mentioned above, it was found that there is little benefit in operating absorption chillers during demand response events in commercial office buildings for the following reasons:

1. Measured thermal response times are long: The time constant from gas input to cooling output of the absorption chiller was measured at approximately 50 minutes, which is longer than many demand response events. The operation of the absorption chiller is further discouraged from the perspective that at part load, the thermal efficiency of an absorption chiller is significantly lower than the electrical efficiency of a compression chiller.[10]
2. Heat recovery to heating hot water had a faster response at 15 minutes but the measured benefits were small.[11] The thermal response time for heat recovery is long, relative to the expected duration of most demand response events. This, in conjunction with 1) a limited likelihood that there will be a need for heating/cooling during the demand response event, and 2) the limited number of events does not incentivise the cost and effort required to maintain and operate the heat recovery system.
3. RERT events typically occur towards the end of the day where a commercial building has only a few hours of cooling demand left, and typically would have minimal heating load.[12] Indeed, given the average RERT event start time, of 4pm, only up to 2 hours of building operation would be expected, shorter than the 3-6 hour duration of the event. This further compromises the viability of the use of heat recovery.
4. Demand response events are infrequent, and their durations are expected to be shorter than RERT events.[13]

## 4 Ongoing Utilisation Plan - Building Owners' Guide

The Building Owners' Guide (below) sets out clear utilisation pathways for building owners with cogeneration/trigeneration (co/trigen) units. It was developed off the findings of this project.

# Building Owners' Guide

### Overview

If your building has a co/trigen system installed, there is a good chance that you will have turned it off due to the costs of operation, leaving you with a lot of sunk capital. However, if the generator is still serviceable, there is an opportunity to use this to create a net positive revenue stream via its use in demand response for the building and for the wider electricity market. This guide will help you understand whether and how to adopt this opportunity, by answering the following questions:

- How can co/trigen systems be used for demand response?
- What is the recommended approach to participate in demand response?

[10] Analysis of the pilot study site demonstrated that at low load, absorption chiller thermal COPs could be as low as 0.2, meaning that the quantity of generated chilled water is very small.
[11] The analysis estimated that operating the heat recovery for space heat for 1.2h, 5h and 9.3h, yielded a reduction in boiler gas consumption of 0-2%, 5% and 30% respectively, (+/- 2.5%)
[12] the average activation/ start time for RERT events was 4pm, based on events that occurred between Jan 2019 and 2022 May, across all regions in the NEM.
[13] Uncertainty in the duration of the demand response events arises from 1) the Wholesale Demand Response Mechanism is relatively new, commencing in October 2021 and the number of events that have occurred is limited (2 times between Oct 2021 and April 2022); 2) the two events to date have been shorter than RERT events, and 3) the duration is variable as depends on settings selected by the demand responder.

- Will it be cost-beneficial?
- Will there be a net environmental benefit/What's the impact on my NABERS Ratings?
- What are the effects of switching from natural gas to biogas

Examples of calculations for financial and environmental impact are provided.

**How can co/trigen systems be used as demand response units?**

The most viable application of co/trigen systems in demand response is where the systems are no longer in regular use but have not been decommissioned. Systems that are in regular use may already be operating during a demand event and therefore unable to provide the scale of response available from a system that only turns on for the demand event.

Due to the sporadic nature of demand response operation, there is little benefit in the operation of heat recovery or absorption chillers during demand response events; the system is operated purely as a gas engine driven generator.

There are two level of demand response that can be considered:

1. Site electricity demand. The generators from the co/trigen units can be used to minimise peak demand charges arising from building energy use peak demands or from the combination of building demand with sudden fluctuations arising from short-term reductions in on-site PV generation (i.e. when the sun goes behind a cloud).
2. Grid demand events. Grid demand events occur when there is a shortfall in generation relative to the load, either because of excessive demand or because of short-term deficiencies of generation. There are several different types of grid demand events:
   - RERT: The Reliability and Emergency Reserve Trader events are signalled by a forecasted shortfall in energy reserves, typically when there's a combination of hot/ extreme weather, high demand, generation or transmission outages. RERT events are enacted by AEMO, are infrequent, and typically last 3 – 6 hours.
   - Wholesale demand response: These are events that are signalled by a spike in the spot price of electricity. Duration is variable, depending on settings selected by the demand responder.
   - FCAS: Frequency Control Ancillary Services. These are events that are signalled by a loss of control of frequency and are fast response events of short duration. Due to these characteristics, they are less well suited for generator response and so are not considered further.

**Revenue Streams**

The key revenue streams available from demand response are as follows:

- Site peak demand management: This is the operation of the generator to even out demand spikes that would otherwise set the demand charges on the site's electricity bill.
- RERT: RERT is a market mechanism that AEMO enacts when electricity reserves are depleted. During a RERT event, the generator can be operated to reduce the site's demand The site receives payment for being on standby when the event is preactivated, and for reducing their demand during the event if the event is activated.[14]

[14] Electricity consumers are also charged a market fee based on their electricity consumption during a RERT event. The reduced demand during RERT events will also lower the total RERT charges incurred.

- Wholesale demand response: This is the operation of the generator to reduce demand, relative to baseline determined from historical site demand. Payment is received based on the magnitude of demand reduction and the spot price at that time.

**Recommended Approach**

The high annual cost of maintaining a generator in working condition for demand response, and the variable nature of returns from demand response, mean that reliably cost-beneficial operation is only possible when all available demand response opportunities are engaged.

For building owners, the use of a third party such as a retailer or a demand response aggregator is strongly recommended rather than direct participation as a market-registered participant. This avoids the complexity of becoming a market-registered participant and creates new opportunities by becoming part of a portfolio of demand response: It enables demand response below 1MW to participate and provides a level of flexibility in response not necessarily available as a stand-alone participant.

The following steps are recommended to get started with investigating whether there is a case in further exploring the use of co/trigen systems in a commercial building:

1. Contact a service provider or electricity retailers that operate virtual power plant or offer demand response programs.
   Examples include EnelX, Shell Energy, EnergyAustralia, and Flow Power. You can contact electricity retailers that are not your retailers.
   Often, service providers can help to provide an estimate of the potential revenue if you choose to participate. They may also be able to help estimate the demand reduction capacity of your site in such events.
2. Determine if it will be cost-effective
3. Determine the environmental impact and impact on your NABERS Rating.

**Will it be cost beneficial?**

The following items need to be considered when determining whether it is cost-beneficial to operate the co/trigen system as demand response units:

- Primary considerations (these have the most significant impact on the assessment)
  - Gas generator operating and maintenance cost
  - Revenue from participating in the demand response events
- Secondary considerations- these have a minor influence on the analysis and can generally be ignored in a first estimate.
  - Avoided costs such as
    - Avoided RERT event charges
    - Avoided grid electricity consumption costs
  - Cost incurred from gas consumed by the generator
  - Generator efficiency

**Will there be a net environmental benefit/What's the impact on my NABERS Ratings?**

Operating a generator for demand response will increase gas use. However, the question of whether this increases or decreases emissions depends on whether the generator produces electricity at a higher or lower emissions intensity than the grid.

At grid level, the real-time impacts of gas engine response are most likely to increase emissions. This is because, in most states, electricity network emissions intensity is lower during demand response events than it is on average. However, this short-term issue must be offset against the extent to which the availability of demand response increases the potential of the grid to have a greater capacity of renewable energy generation connected. From this perspective, it is expected that the overall effect is a reduction in emissions overall.

At site level, emission calculations for reporting and for NABERS ratings are based on annual average emission factors. In 2022, the current state of play is:

- VIC: Gas generator operation is likely to reduce overall site emissions
- QLD, NSW, NT, and WA: Gas generator operation may reduce emissions for generators operating at efficiencies above 23%, 26%, 27%, and 29%, respectively.
- SA and TAS: Gas generator operation will increase emissions

It is noted that the grid emissions intensity figures for each state are all on a downward trend so over time the tendency will be towards gas generators to become more emissions intense than the local grid. In all cases, however, the small number and duration of demand response events means that the actual impact as a proportion of site emissions is likely to be close to undetectable.

**What are the effects of switching from natural gas to biogas?**

There is currently a trial scheme to sell biogas across the gas network similarly to how Green Power is sold on the electricity network. The financial implication of using this opportunity to switch from natural gas to (reticulated) biogas is currently unknown due to uncertainty in the retail price of biogas. However, the approach described in the early section can be used to determine if it is cost beneficial.

Switching from natural gas to biogas will be make the emissions intensity lower than the average grid emissions intensity across all states and territories because the emission factor for using biogas is approximately 10 times lower than that of natural gas.

**Example:**

The following is an example of how the cost-effectiveness, environmental and NABERS Rating impacts of using gas generators as demand units can be assessed. The revenue rates mentioned are examples and may not necessarily reflect the actual rates on offer. Rates will vary depending on the service provider and location. More accurate ratings should be obtained from the service provider or electricity retailer.

| **Example: Cost-effectiveness assessment** |
| --- |
| Consider a building in Victoria, with a trigeneration capacity of 1 MW. The full capacity (1MW) is contracted to participate in RERT, network and wholesale demand response events. As the cost of operating and maintaining (O&M) the cogeneration and trigeneration system can vary widely, three different annual O&M (excluding the fuel costs) costs are considered in this example; $40,000, $60,000 and $80,000. These are equivalent to $40, $60 and $80 per kWe of capacity per year. |

***RERT Event Participation:***
Estimated Revenue from RERT event participation (assuming one 3 hour event in a year):

Revenue from RERT events

$$\begin{aligned}&\mathit{Revenue\ from\ event\ preactivation}\\&\quad = \mathit{Preactivation\ Rate}\ (\$/MW) \times \mathit{Capacity}\ (MW)\ \times \mathit{Number\ of\ preactivation\ events}\\&\quad = \$10{,}000\ \times 1\ \times 1\ event = \$10{,}000\end{aligned}$$

$$\begin{aligned}&\mathit{Revenue\ from\ the\ activated\ event}\\&\quad = \ \mathit{Activation\ Rate}\ (\$/MWh) \times \mathit{Capacity}\ (MW) \times \mathit{Dispatch\ Duration}(h)\\&\quad = \$9000 \times 1\ MW\ \ \times 3h = \$27{,}000\end{aligned}$$

$$\begin{aligned}&\mathit{Total\ Revenue\ from\ the\ event}\\&\quad = \ \mathit{Revenue\ from\ event\ preactivation} + \mathit{Revenue\ from\ the\ activated\ event}\\&\quad = \$37{,}000\end{aligned}$$

Note: if no RERT events are preactivated during the year, there will be no RERT payments.

***Participation in Wholesale Demand Response Events:***
Here is it assumed that a contract with the third party/ service provider has been established and that there is an annual payment based on the capacity of the system ($50,000 per MW) plus a payment based on the number and duration of events.

In the case where there are no events:

$$\begin{aligned}&\mathit{Revenue\ from\ WDR}\ = \mathit{Annual\ Capacity\ Rate}\ (\$/MWh) \times \mathit{Capacity}\ (MW)\\&= \$50{,}000 \times 1\ MW = \$50{,}000\end{aligned}$$

If there are 40 h worth of events in the year, and for all events, the site reduces the grid demand by 1 MW,

$$\begin{aligned}&\mathit{Revenue\ from\ WDR}\\&\quad = \mathit{Annual\ Capacity\ Rate}\ (\$/MW) \times \mathit{Capacity}\ (MW)\\&\quad + \mathit{Dispatch\ Rate}\ (\$/MWh) \times \mathit{Capacity}\ (MW) \times \mathit{Event\ Duration}\ (h)\\&\quad = \$50{,}000 \times 1\ MW + \$200 \times 40\ h = \$60{,}000\end{aligned}$$

**Total Revenue versus O&M Cost:**

$$\mathit{Total\ Revenue\ from\ RERT\ and\ WDR\ Events} = \ \$37{,}000 + \$60{,}000 = \$97{,}000$$

Assuming that the cost of operating and maintaining a 1 MW system is $80,000, the total revenue from the event is higher than the cost of operating and maintaining the system ($97,000 versus $80,000). The financial outcome is more promising for systems with a lower O&M cost; e.g. ($97,000 versus $40,000 and $60,000).

**Additional Note:**

Calculations for the cost of generator fuel consumption, avoided energy consumption costs, and avoided RERT charges are not shown. However, these components have a minor contribution to the overall analysis. It is estimated that for all assumptions mentioned above, gas consumption will cost approximately $7,000, and the avoided grid electricity consumption will save approximately $5,000.

The secondary costs can be estimated using the following equations:

1. $$Estimated\ Avoided\ RERT\ charges = Capacity\ (MW) \times Dispatch\ Duration(h) \times AEMO\ RERT\ Charge$$
2. $$Gas\ consumption\ Charge = ((Capacity\ (MW) \times Dispatch\ Duration(h))/\eta_{el}) \times Gas\ Price\ (\$/kWh)$$
3. $$Avoided\ Energy\ Consumption = \left(Capacity\ (MW) \times Dispatch\ Duration(h)\right) \times Electricity\ Consumption\ Charge(\$/kWh)$$

Due to the sporadic nature of grid events and using the site's historical demand to determine the magnitude of demand response in an actual event, participation in grid events is unlikely to yield peak demand savings. Peak demand savings may be realised by operating the gas generators to limit the peak demand at a site without on-site renewable generation. However, this mode of operation may have potential negative impacts to the demand response revenue streams discussed in this guide.

**Example: Net Environmental Benefit and Impact on NABERS Ratings**

Consider a site in Victoria where the generator has an electrical efficiency ($\eta_{el}$)[15] of 25%.

$$Generator\ Emission\ Factor = 3.6 \times \frac{Gas\ Emissions\ Factor}{Generator\ Efficiency} = 3.6 \times \frac{0.05553}{25\%} = 0.7996\ \mathrm{Kg\ CO_{2-e}/kWh}$$

This generator emissions factor is less than the grid emission factor for Victoria (1.09 Kg $CO_2$/kWh). Therefore, there is a net environmental benefit of using the co/trigen systems in this case.

| State | Gas Emissions Factor (Natural Gas) (Kg $CO_2$-e/KJ) | Grid Emissions Factor (Kg $CO_2$/kWh) |
|---|---|---|
| NSW & ACT | 0.06463 | 0.9 |
| VIC | 0.05553 | 1.09 |
| QLD | 0.06033 | 0.93 |
| SA | 0.06223 | 0.52 |
| WA | 0.05563 | 0.7 |
| TAS | 0.05153 | 0.17 |
| NT | 0.05153 | 0.7 |

**Further Reading:**

AEMO has information on each of the demand response methods discussed above on its website.

- RERT:

[15] The electrical efficiency can be determined either from generator specification documents, or by dividing the amount of electricity generated by the amount of gas consumed by the generator.

- "Fact Sheet - The Reliability and Emergency Reserve trader" https://aemo.com.au/-/media/files/learn/fact-sheets/rert-fact-sheet-2020.pdf
- Wholesale Demand Response:
  - "Wholesale demand response mechanism final rule" https://www.aemc.gov.au/sites/default/files/documents/information_sheet_-_for_publication.pdf
  - "Wholesale demand response mechanism – How it works" https://aemo.com.au/en/initiatives/trials-and-initiatives/wholesale-demand-response-mechanism
- FCAS:
  - "Guide to Ancillary Services in the National Electricity Market" https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/guide-to-ancillary-services-in-the-national-electricity-market.pdf
  - "Ancillary services" https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services

# 5 Challenges and Lessons Learnt

Challenges associated with the primary objectives and applicability of the project outcomes include:

- **Site suitability:** The current operational statuses of gas generators vary, with some sites using the generators for base load, while others have decommissioned or removed them. Consequently, not all sites are positioned well for operating their gas generators as demand response units. Where a system is currently in regular operation as a cogeneration or trigeneration system, the incremental load available to respond to a demand event is a fraction of system capacity and thus often below the threshold for useful outcomes. As a result, the operation of gas generators for demand management is best considered in terms of generators that are not operated for underlying site demand.

- **Relevance of cogeneration and trigeneration heat recovery:** The thermal response times of cogeneration and trigeneration systems are relatively slow. Assessment of the pilot study's site data indicated that the time constant from gas input to the generator to cooling output from the absorption chiller at startup is of the order of 50 minutes. Consequently, the heat recovery of the system is not a relevant consideration in relation to the economics and operation of gas generators for demand management.

- **Financial outcome:** The financial outcome of using the gas generators as demand response units varies depending on multiple parameters. Amongst them, the operating and maintenance cost was identified as the primary factor with the largest influence. However, a wide range of O&M costs identified was wide, from $14 to $113 per kWe known. As a consequence, the achievement of a positive financial return from the operation of gas generators requires the capture of essentially all demand management revenue streams.

- **Operation and maintenance cost:** The O&M cost is one of the challenges associated with using the gas generators as demand response units. In addition to it significantly influencing the net financial outcome, one of the main reasons for the decommissioning/removal of cogeneration and trigeneration systems in buildings is that the cost of gas and O&M far exceeds the benefit in terms of avoided electricity cost.

- **Environmental outcome:** In general, the real-time emissions of the grid during demand management events are lower than the annual average. Consequently, the net real-time environmental impact of operating gas generators during grid demand events is generally negative. However, the annual emissions are higher than the event-specific factors and are often favourable for the use of the generator. This effect is amplified for NABERS ratings, which are based on lagging indicators of annual emissions intensity.

- **Data Clearing House and Demand Response**: The implementation of gas generator driven demand response does not require the full functionality offered by a platform such as DCH. However, opportunities for additional flexible demand within HVAC systems may need a DCH-level functionality to be enabled.

## 6 Conclusion

The feasibility and impact of using under-utilised gas-fired generators in commercial buildings has been investigated. The objectives of the sub-project were investigated using a combination of methods; this included consultation with third parties that provided demand response services, review of the installed cogeneration and trigeneration capacity, analysis of electricity market data and data from a pilot study site with both on-site renewable energy generation and an operational trigeneration system.

The review of the installed cogeneration and trigeneration capacity found that in the past 20 years, at least 120 MW (electrical) of cogeneration and trigeneration capacity has been installed in buildings (commercial, office towers, retail and residential), hospitals, and recreational facilities and precincts. In the built environment, the largest co/trigen capacities are likely to be in hospitals, followed by data centres, airports, and office buildings. The current status of these installations vary. Some sites use them to provide base load, while many other sites either already have, or planned to, switch off or decommission the cogeneration/trigeneration systems. The operation of gas generators for demand management is best suited to generators that are not operated for underlying site demand.

Key findings from this project include:

    - Operating gas generators to only meet the short-term changes in on-site renewable generation output is unlikely to cover the O&M costs for the generator.
    - Achievement of a positive financial return from operating the gas generators requires, essentially, all demand management revenue streams to be captured due to the high O&M costs for generators
- The net real-time environmental impact of gas generator operation is generally negative. However, the impact on NABERS ratings is more generally positive, and it is expected that the holistic impact allowing for increased connection of renewable energy to the grid enabled by greater demand response capacity would be strongly positive.
- The implementation of gas generator driven demand response does not require the full functionality offered by a platform such as DCH. However, opportunities for additional flexible demand may need a DCH-level functionality to be enabled

Strategies for operating the gas generators (from cogeneration and trigeneration systems) in response to site-level and grid-level events were developed and reported. The financial and environmental impacts were also assessed. Finally, a Building Owners' Guide was developed; it guides building owners with co/trigen units through a series of steps enabling them to decide if they should further consider operating the co/trigen systems as demand response units.

In terms of future opportunities, while the results indicate potential financially viable demand response is available from this subsector, it is noted that building owners are decommissioning these systems because the financial and environmental case they were built for is evaporating. Thus, the window of opportunity is closing rapidly, and timely intervention would be needed to capture the full potential benefit to the grid. Meantime, our discussions with demand response aggregators indicates that classic building demand response – in terms of the wind back of HVAC power demand – is largely untouched due to the perceived and real risks and complexities associated with the potential to create occupant discomfort. The development of a means of quickly characterising the quantity, duration and response rate of available load reduction could significantly speed the access of the grid to this significant resource.

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