Integrated power-to-gas and gas-to-power with air and natural gas storage

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Abstract

Compressed air energy storage (CAES) is an energy storage option with a history of almost half a century. The concept of CAES is formed around the integration of this system with a gas-fired power generator. Here, we introduce a methodology that a gas power generating plant installs both air and natural gas storage system to utilize their stored energy as well as the real economic value of natural gas following market dynamics. We present a detailed mixed-integer techno-economic formulation for operation scheduling of such a system. An example is also provided for a 180 MW gas generator in Australia with results showing how the storage facilities could improve the revenues of the plant. The analyses clearly show optimal conditions for a mix of natural gas and storage sizes in order to achieve the highest economic revenue.

Keywords: Energy storage; electrical grid; power flow; sustainability; GHG emissions; planning and scheduling; power-to-gas, PtG, P2G, gas-to-power, GtP, G2P.

1 Background

1.1 Natural gas supply-demand

Until a few centuries ago, wood was the only energy source until coal was explored and gradually became the dominant source of global energy. The age of coal continued until oil and gas joined the mix. Gradually, along with these energy sources, hydro, nuclear, and renewables, diversified the energy portfolio. Unlike renewables, fossil fuel sources are not distributed evenly around the world and this has led to the development of a so-called “value chain” with a few components, namely exploration/production, storage (at production), shipping, storage (at consumer side), and consumption. In many cases, producers and consumers are distant. Shipping accounts for a major fraction of the delivered energy costs over a value chain. This, therefore, signifies the importance of (volumetric) energy intensity of fuels. Natural gas (NG) is the worst fossil fuel in terms of energy intensity while being the best for environmental impacts. The lower C/H ratio and thus lower carbon emissions compared to oil and coal, along with reduced emissions of oxides (nitrogen and sulfur) and particulates, make NG a very environmentally attractive option. More importantly, the costs of processes based on NG such as power generation are much lower than for coal or oil [1]. As policies and/or mechanisms for carbon taxes/credits/penalties are discussed, the economic advantages of NG increase. All these are leading to the rapid growth of NG exploration, processing and consumption. The current growth in energy demand along with global concerns and treaties about climate protection will continue to foster NG demand. It is projected that NG demand will dominate coal by 2035 [2].

Natural gas volume intensity issue is not only the problem of national gas companies (NGC) for procurement and delivery from overseas suppliers to local consumers. It even causes problems for local users. Given the difficulty of storage, the end-users become vulnerable to any interruption in NG supply. Furthermore, in liberalized local markets, the electricity and gas prices dynamically fluctuate based on supply-demand balances. Therefore, as a local consumer (e.g. a gas-powered electricity generator), it becomes critical to plan the energy demand and make future contracts to minimize the NG purchase costs from the (generally high-price) spot market. Again, the main obstacle in this business, for the market players, is the low volume intensity of natural gas which makes the storage a challenge. Nevertheless, this issue has been addressed a few decades ago by storing NG in depleted reservoirs or by building small LNG process plants, called peak-shavers. The first successful LNG peak-shaving unit was built in Racine, Wisconsin, in 1965 with a storage size of ~25 million scf. This was followed by the second relatively larger unit (~600 million scf) in Portland, Oregon in 1967 [3].

Take-or-pay contracts are common traditional mechanisms in the natural gas market which still exist. The advantage of such contracts is the lower contracted price of the commodity, while the disadvantage is a lack of compensation for surplus quantity. The peak shavers, however, allow a gas power generating company to store the surplus contracted NG (during low-demand electricity periods) for consumption during high-demand periods. Moreover, such storage arrangements could provide the companies the flexibility of buying and storing NG at low price periods for later use when NG and electricity prices are high.

There are also some cases that gas-fired power companies have used gas pipelines to procure and store NG at elevated pressures (and thus quantity) within the pipes for later use. An example is Coloongra a 667 MW peak-following power plant in Australia. Given that the existing gas pipeline could not supply the peak demand of the power plant, the company installed nine kilometers of looped 42-inch storage pipeline along with a compressor station that increases gas pressure from 34 bars to 130 bars, and a let-down station [4]. We will further continue this discussion after introducing electricity supply chain and its contemporary management issues.

1.2 Electricity supply-demand

The conventional electricity supply chain comprises generator, transmission and distribution network (analogous to the pipeline for NG), and end-user. The supply chain management of electron energy is very different from that of fuel energies (gas, liquid, or solid form). On the one hand, electricity can be instantaneously transmitted from one location to another where it is very costly and time-consuming for fuel energies. On the other hand, management of electron during oversupply periods is a challenge compared with that of fuels. This limitation has immediately provoked the need for energy storage from very early days of electricity market development.

The initial intentions of electrical energy storage (EES) were peak-shaving or short-term outage prevention [5]. Today, EES is used for many other reasons including the delay of capacity/network expansion, frequency regulation, voltage balancing (prevent brownouts), etc. [6]. As such, each of the energy storage technologies is suitable for a given objective. They are usually categorized based on a time scale of applications such as instantaneous (less than a few seconds), short-term (less than a few minutes), mid-term (less than a few hours), and long-term (days) [7]. A detailed background on the historical development of various energy storage options can be found in the electricity storage handbook published by Sandia National Laboratories [8].

The attention to electricity storage, however, triggered when numerous intermittent renewable power sources, especially PV and the wind, emerged at various sizes from a few kilowatts to hundreds of megawatts. These power sources, whether grid-connected or off-grid (stand-alone), require storage (for load-balancing) due to their output intermittency as a result of weather/seasonal fluctuations. Historically, pumped hydro has been the dominant option of electricity storage at large centralized power stations due to a notably lower cost compared with others [9]. However, this popular storage option is geographically limited and is not available/feasible for all levels of grid use including distribution and community level (e.g. residential, commercial, etc.) for obvious reasons. As such, a portfolio of storage options is being investigated for various applications. Figure 1 from Electricity Storage Association shows the position of various energy storage technologies based on their typical power ratings and discharge times. Those with lower discharge time are suitable for power quality management and uninterruptible power supply (UPS). Those with large sizes and very high discharge times are suitable for bulk power management. In the middle are the storage systems suitable for T&D support and load shifting.

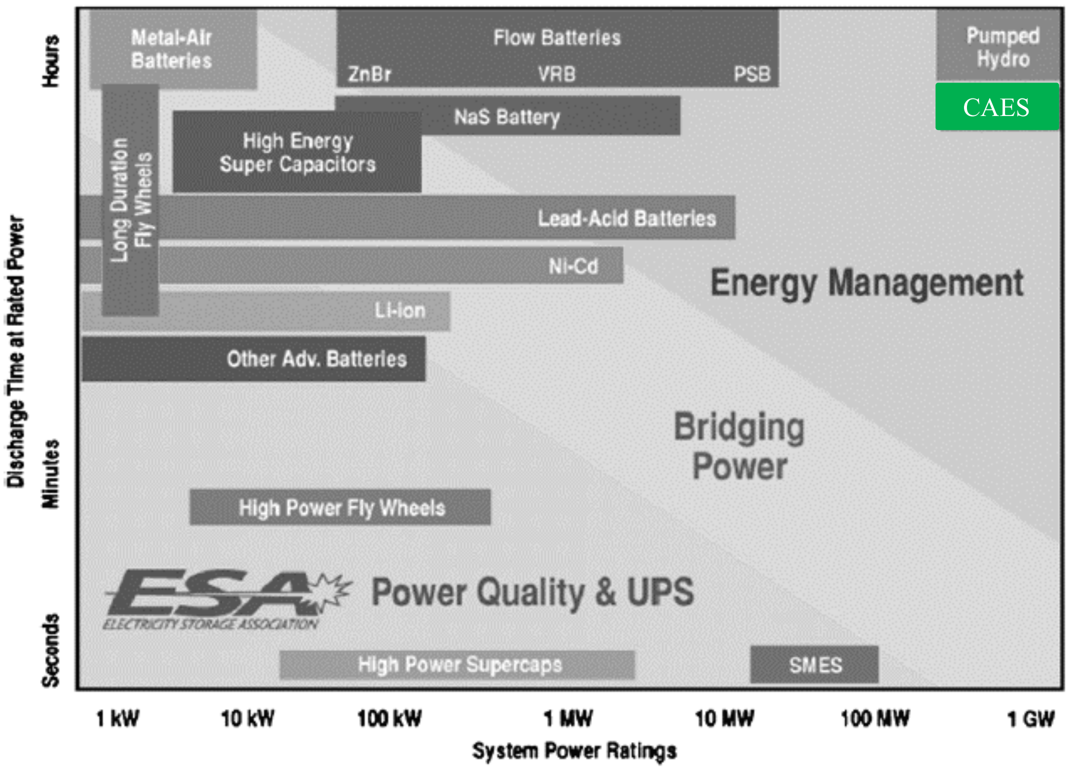


Figure 1: Screening of energy storage systems for various applications based on their power ratings and discharge times (Image: courtesy of the Electricity Storage Association)

Figure 1 clearly shows how each available storage technology has an optimal position in the electricity supply chain based on required size and response time. Our focus in this study is electrical energy storage in gases. Figure 1 has shown the case of CAES in the top right meaning that CAES technology is best for large-scale applications. The figure also shows that CAES is suitable only for energy management objectives due to its response time in the order of hours. In this paper, we will also discuss other types of EES in gases which are not mentioned in ESA's chart (Figure 1).

1.3 Interactive gas-electricity market

We already discussed, briefly, the natural gas and electricity supply chains. Traditionally, the linkage between these two has been one way, i.e. electricity supply chain has been a consumer of natural gas. In other words, gas has been converted to power (gas-to-power, GtP, or G2P) in gas-fired power plants. But, in recent years with the increase in renewable power generation technology installations, the reverse direction has also received attention i.e. conversion of surplus power to gas (PtG or P2G) [10]. This interaction could improve the flexibility of both markets, reduce operation risks, and result in lower cost of delivered energy for the end-users.

The core motivation of PtG is to utilize surplus electrical power from the electricity network for application in the natural gas network. From various options for electrical energy storage during over-supply, PtG could happen in two ways; (1) Chemical approach: use of power for the electrochemical production of gases, especially hydrogen and methane, and (2) Potential approach: use of power for pressurization or phase change of a gas (air, NG, etc.).

The focus of this paper is on the latter option which, unlike the former route, does not involve any chemical reaction. Rather it changes the potential energy level of gases by pressurization, or at some cases by phase change (e.g. liquefaction, or hydrate formation). Compressed air energy storage (CAES) is a promising electrical energy storage option. It has almost four decades of industrial experience since the first plant was built in Huntorf, Germany, 1978 [11]. Figure 2 shows a schematic of the process. Gas turbines receive NG at high pressures and the combustion generally happens at NG pressure. Therefore, atmospheric-pressure air should be compressed to NG pressure before being supplied to the combustion chamber. The high-temperature and high-pressure exhaust gas is directed to the expander to generate electrical power. A notable fraction of the power is however used for air compression. On this basis, compression and storage of air could be advantageous in certain scenarios: First, when a gas power plant has made a take-or-pay NG contract and demand for electricity is low, the NG could be used for air compression and storage, so that during high electricity price the stored energy could be utilized for power generation. Second, it could be used for grid management and power supply reliability by load following in the context of base-load inflexible power plants such as nuclear [12]. A third interest is similar to the second in terms of grid management and is mainly motivated by utilizing oversupplied renewable electrical energy. During the electricity oversupply periods, the air compressor can be driven by an electrical motor (with energy supplied by the grid) to compress and store air for later use.

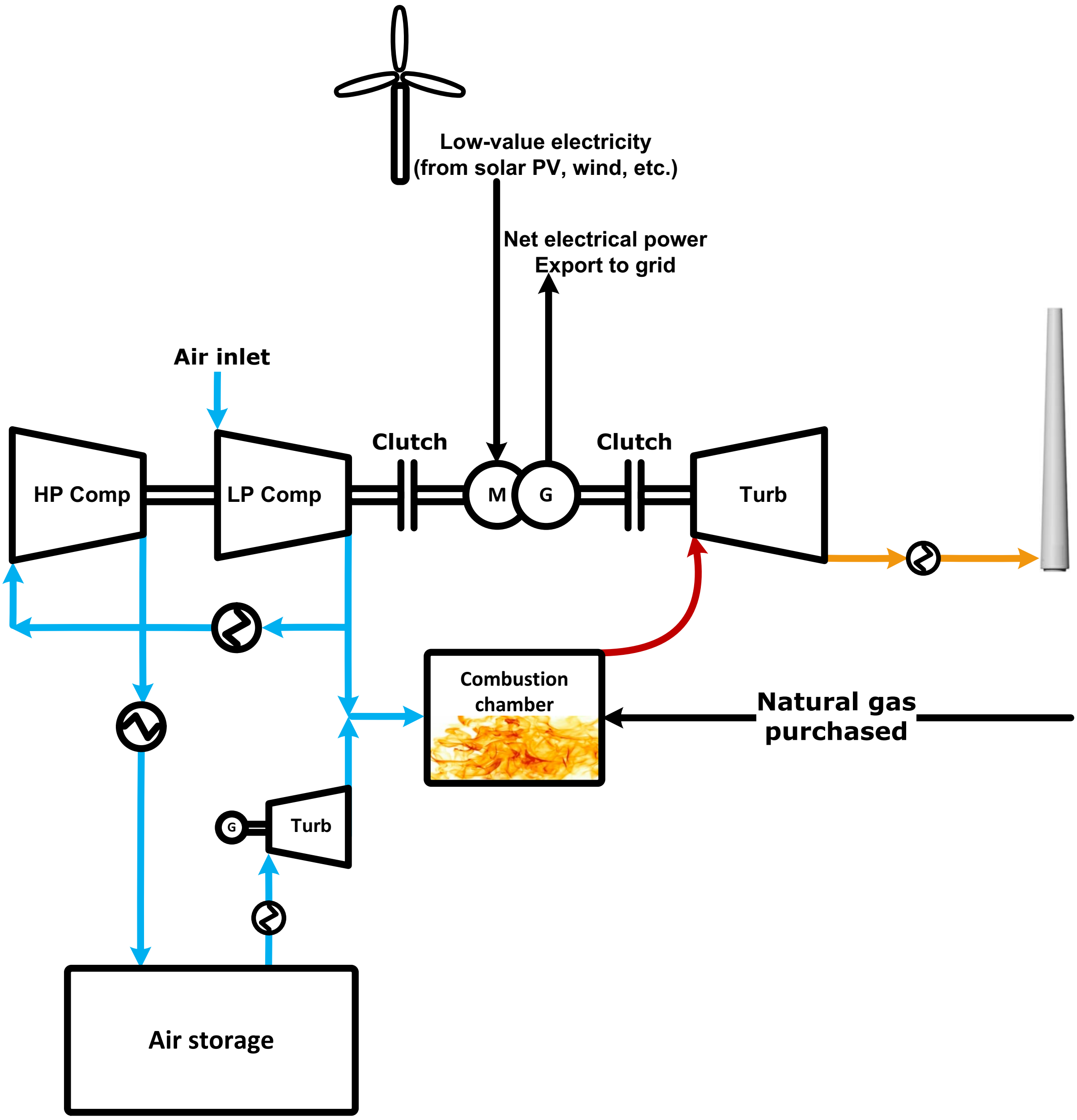


Figure 2: Schematics of gas-fired power generator with compressed air energy storage (CAES)

The surplus electrical energy could also be used for pressurization in the natural gas network. For instance, a pipeline route could be over-pressurized at the location of unused electrical energy, then the pressured gas is transferred to the demand location where the gas could then be depressurized (by generating electricity) and supplied to the demand market at the desired pressure. Except for the CAES, pressurization has received very little attention in the literature as a means of unused electrical energy storage. As such we will have special attention to pressurization in the remainder of this paper.

Given the lower cost of compression versus liquefaction, it has been proven economical to transport NG in the form of CNG when the demand side is located at shorter distances [13]. CNG tanker is a concept for doing this task by pressurizing and storing NG in tubes or vessels. Such vessels could be used for CAES applications [14].

In this study, we propose using CNG vessels not for sea transport rather, for onshore energy storage. Such modules could be in fact used for storage of any type of gases, including air and natural gas. Storage of natural gas could have a double economic advantage: the first benefit is pressurization of NG and thus storing unused electrical energy in the form of potential energy for recovery at a later time. Secondly, natural gas during low-price periods could be purchased and stored at the modules for use or re-sell at high price NG or electricity periods. This double benefit improves the economics of this energy storage option in the face of installation costs of above-ground storage systems. Next, we discuss the problem formulation

2 Problem definition

Consider a power generating company (addressed as “the company”) that operates a gas-fired power plant (addressed as “the generator”) with a known baseline gross power capacity (Figure 3a). The company uses natural gas with high-heating-value (HHV) of H and generates flue gas with a CO_2 amount of β per unit weight of fuel consumed. The given planning horizon is P multiple periods (p: 1, 2, …, P) of a given fixed length (minute, hour, day, week, etc.) and the current optimization study is occurring in the base period (p = 0). Now the company has installed an air storage system with storage capacity of V_S^A unit volume and maximum pressure of P^A*. The company may also install a NG storage system with capacity of V_S^{NG} unit volume and maximum operating pressure of $P^{NG}*$.

Figure 3b illustrates a schematic of a storage-integrated gas-fired power plant. The inlet air (at temperature and pressure of $T_{LP.i}^A$ and $P_{LP.i}^A$) is compressed in low pressure (LP) compressor (to temperature and pressure of $T_{LP.o}^A$ and $P_{LP.o}^A$). If the proces is in power generation mode, the air is directed to the combustion chamber; otherwise it is cooled to temperature of $T_{HP.i}^A$ and is sent to a high-pressure (HP) compression unit. Then, the HP air (at temperature and pressure of $T_{HP.o}^A$ and $P_{HP.o}^A$) is cooled to the temperature of the storage tank T_S^A and sent for storage. At such a scenario when air is compressed for storage (which happens during low-demand electricity periods), the compression energy is supplied by the grid.

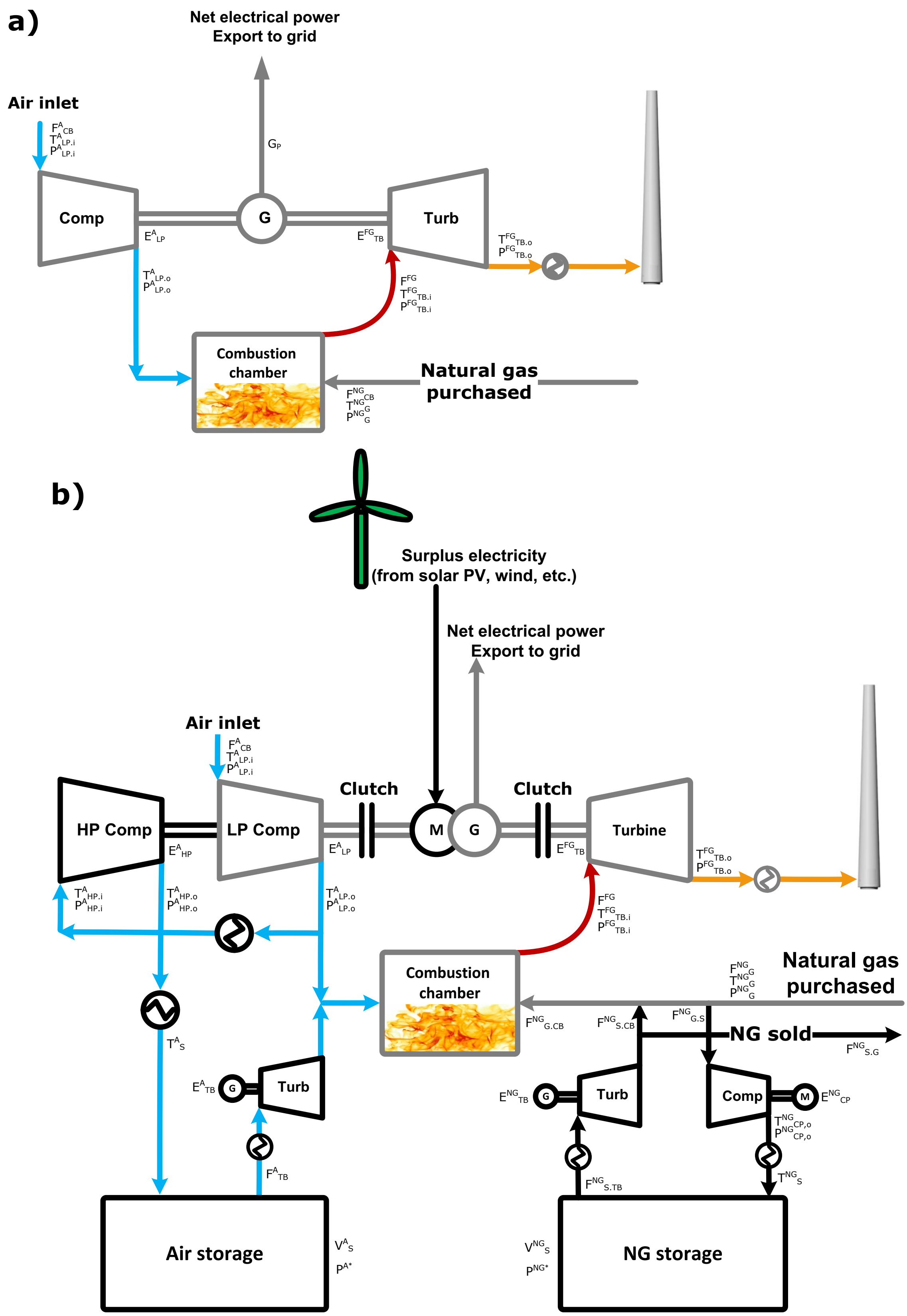


Figure 3: Schematic of a gas-fired power plant: a) without storage, and b) storage-integrated

During high-demand electricity periods, the stored air with flowrate of $F_{TB,p}^{A}$ mass unit is pre-heated and directed to the expander to reduce its pressure to that of the combustion chamber (or $P_{LP.o}^{A}$). As such, the expander turbine can generate $E_{TB,p}^{A}$ extra power to export to the grid during period p.

The purchased natural gas (at temperature and pressure of T_{G}^{NG} and P_{G}^{NG}) can be fed directly to the combustion chamber for power generation, and/or it could be further compressed (to temperature and pressure of $T_{CP.o}^{NG}$ and $P_{CP.o}^{NG}$) to be stored in NG storage system after cooling. During demand periods for NG, the stored NG with flowrate of $F_{S.TB,p}^{NG}$ mass unit is pre-heated and directed to turbine to reduce its pressure to that of pipeline (P_{G}^{NG}). As such the turbine can generate $E_{TB,p}^{NG}$ extra power to export to the grid at period p. The expanded gas could be used locally and/or re-sold to the spot market.

The air (ambient and/or from storage) when combusted with NG (from market and/or storage) generates a high-volume and high-temperature flue gas (FG) which when directed to the turbine can generate $E_{TB,p}^{FG}$ power accounting for the main power output of the plant. The outlet of the turbine will be a flue gas at near-atmospheric pressure to be vented through a stack.

In a liberalized market, the price of electricity and natural gas are defined by market supply-demand dynamics and numerous factors such as weather conditions, working-day/holiday, resulting in different demands which define the market price. The electricity price can reach as high as a hundred times its average annual price at peak loads and, surprisingly, can have negative values in some off-peak periods [15]. Therefore, forecasting the electricity price as well as natural gas is an essential task for power generating companies. Here, we assume that the company, with access to historical periodical data, has projected the pool price of electricity, E_p, and fuel (natural gas), FP_p, at period p (p: 1, 2, …, P). With the existence of air and/or NG storage systems, the critical decision question becomes how to operate the integrated processes to capture the maximum benefits of electricity price and NG fuel price. Figure 4 highlights some of the possible scenarios. For instance, at a certain period when both NG and electricity prices are low, the plant might decide to purchase NG and electricity for compression and storage of NG and air. At another circumstance, when NG price is low, but electricity price is high, the company will utilize the stored air to generate electricity at maximum possibility. On the other hand, during periods with high NG price, if the electricity price is low, the company may sell some stored NG to the market. It may also store air. When both electricity and NG prices are high, the company may use both stored air and NG to generate power for sale. Here, our intention is to develop a rigorous operation scheduling algorithm which is capable of making the best decision at any period of time with the objective of maximizing the economic benefits of the company over the planning horizon.

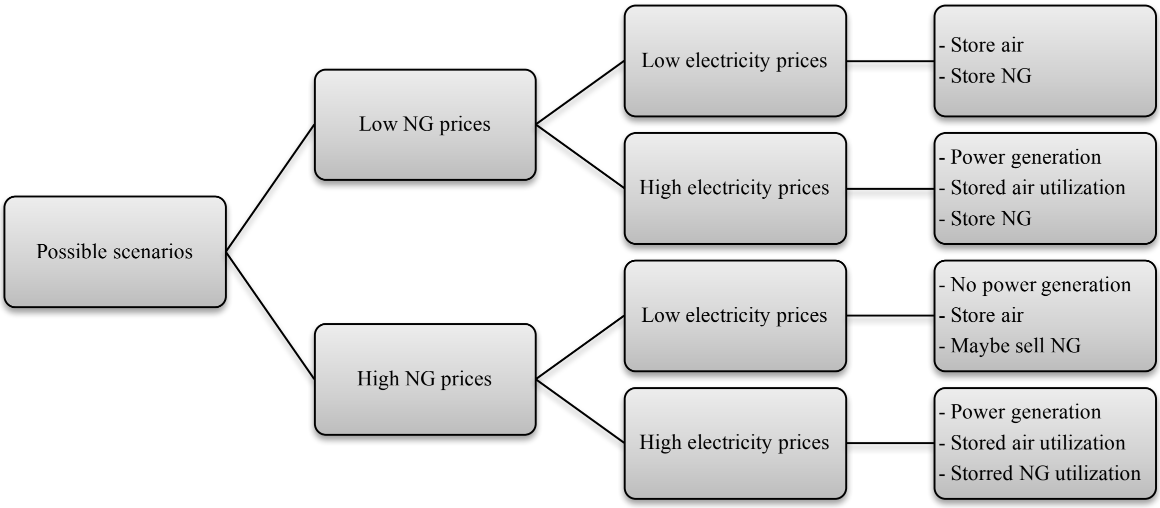


Figure 4: Some possible operation scenarios of a storage-integrated gas-fired power plant

3 Formulation

3.1 Gas-fired power plant without storage

The plant's thermodynamics

Natural gas is burnt in the combustion chamber in the presence of air. Generally, excess air is required in order to achieve 100% reaction efficiency and thus fuel economy. Generally, the flowrates of NG and air are related with a constant value called air-to-fuel ratio, *AFR*. Hence, during operation period p, if the NG mass flowrate to the combustion chamber is $F_{CB,p}^{NG}$, the value for air flowrate would be,

$$F_{CB,p}^{A} = AFR\, F_{CB,p}^{NG} \qquad 1 \le p \le P \qquad (1)$$

Generally, the combustion takes place at the pressure of the natural gas. Therefore, the ambient air needs to be compressed. The energy used for the compression of $F_{CB,p}^{A}$ from pressure of $P_{LP.i}^{A}$ to $P_{LP.o}^{A}$ is:

$$E_{LP,p}^{A} = \frac{F_{CB,p}^{A}}{\eta_{LP}} \frac{z_{LP}^{A} R T_{LPi}^{A}}{M^{A}} \frac{k_{LP}^{A}}{k_{LP}^{A}-1} \left[\left(\frac{P_{LP.o}^{A}}{P_{LP.i}^{A}} \right)^{\frac{k_{LP}^{A}-1}{k_{LP}^{A}}} - 1 \right] \qquad 1 \leq p \leq P \tag{2}$$

where, η_{LP} is the compressor efficiency, R is gas constant, and M^{A} is air molecular weight. z_{LP}^{A} and k_{LP}^{A} are average air compressibility factor and polytropic constant, respectively, for the operating condition of the compressor.

The combustion product is a high-temperature and high-pressure flue gas which based on conservation of mass law has flowrate of

$$F_{p}^{FG} = F_{CB,p}^{A} + F_{CB,p}^{NG} \qquad 1 \leq p \leq P \tag{3}$$

The flue gas is directed to the expansion turbine and generates electricity with the rate given by,

$$E_{TB,p}^{FG} = \eta_{TB}^{FG} F_{p}^{FG} \frac{z_{TB}^{FG} R T_{TB.i}^{FG}}{M^{FG}} \frac{k_{TB}^{FG}}{k_{TB}^{FG}-1} \left[\left(\frac{P_{TB.o}^{FG}}{P_{TB.i}^{FG}} \right)^{\frac{k_{TB}^{FG}-1}{k_{TB}^{FG}}} - 1 \right] 1 \leq p \leq P \tag{4}$$

where, η_{TB}^{FG} is the FG turbine efficiency, and M^{FG} is FG molecular weight. z_{TB}^{FG} and k_{TB}^{FG} are average FG compressibility factor and polytropic constant, respectively, for the operating condition of the turbine. $T_{TB.i}^{FG}$ is the adiabatic combustion temperature which flue gas carries right at the inlet of the turbine.

At any period of time, the generator can operate at its maximum capability i.e. the generatable capacity GC_{p}^{U}. For gas generator this is given by,

$$GC_{p}^{U} = E_{TB}^{FG*} - E_{LP}^{A*} \qquad 1 \leq p \leq P \tag{5}$$

where, E_{TB}^{FG*} and E_{LP}^{A*} are design capacities of flue gas turbine and air compressor, respectively.

During operation at partial load, the gross electricity of the power plant is the difference of the turbine and compressor powers given by,

$$G_{p} = E_{TB,p}^{FG} - E_{LP,p}^{A} \qquad 1 \leq p \leq P \tag{6}$$

A small fraction of this power is used locally for auxiliary units (Aux) and the remainder, called net power, is exported to the grid, given by

$$G_{p}^{net} = (1 - Aux) G_{p} \qquad 1 \leq p \leq P \tag{7}$$

The plant's scheduling

Without any storage arrangements (Figure 3a), the plant is, in fact, a typical gas-fired power plant with a compressor for air compression and a turbine for flue gas expansion (and thus power generation) after combustion with natural gas. With this condition, the objective of the company is to maximize its profit from power generation and sales to the market. When the electricity prices are marginally lower than its generation costs, it would be beneficial for the company to run at an optimal capacity and export electricity to the grid. Otherwise, it might be a feasible option for the company to operate at the no-load condition or to shutdown. Obviously, all units (compressor, turbine, etc.) will be on during operation, and off during shutdown period (not true for a storage-integrated system). Here we introduce the formulations for optimal operation scheduling of such a plant.

As discussed, due to load variations, enforced by demand market, a generator will often need to turn off for some time during low demand periods until the demand ramps up again. However, generators cannot quickly and repeatedly be turned on/off without wear or damage. The parameters α_{gen} and γ_{gen}reflect the minimum amount of periods that a generator needs to be on/off, after being turned on/off, respectively. Complying with these limitations requires knowledge of generator's length of operation or inaction since the last start-up or shutdown period, respectively. This, by itself, necessitates the knowledge of the exact time when the generator was last turned on/off. Therefore, we define the following binary variable for each generator at period p:

$$yo_p = \begin{cases} 1, & \text{if generator is operating during period } p \\ 0, & \text{otherwise} \end{cases} \qquad 1 \le p \le P$$

This allows us to impose a constraint on the air flowrate to the compression system. When operating during period p, air enters the LP compressor with flowrate of $F^A_{LP,p} = F^A_{CB,p}$ mass unit which should not exceed the design flowrate (F^{A*}). This is given by

$$F^A_{LP,p} \le yo_p F^{A*} \qquad 1 \le p \le P \tag{8}$$

Let the binary variable ys_p denote the period p that the generator starts up after its previous off period given by

$$ys_p = \begin{cases} 1, & \text{if generator starts up at period } p \\ 0, & \text{otherwise} \end{cases} \qquad 1 \le p \le P$$

Therefore, given the ramp up/down limitations, if the generator starts up at period p (i.e. ys_p=1), yo_p should be on for the next α_{gen} periods. This is given by [16],

$$ys_p\alpha_{gen} \leq \sum_{p'=p}^{\min[P,p+\alpha_{gen}-1]} yo_{p'} \qquad 1 \leq p \leq P \tag{9}$$

Logically, the generator cannot operate for α_{gen} periods if it starts up sometime within the planning horizon when less than α_{gen} periods are left. For instance, the above constraint does not consider the condition that a generator starts up when $\alpha_{gen} = 5$, while only 4 periods are left to the end of planning horizon (*P*). To enable the system to operate under such conditions, we have,

$$\sum_{p'=P-\alpha_{gen}+2}^{P} \left(yo_{p'} - ys_{p'}\right) \geq 0 \qquad 1 \leq p \leq P \tag{10}$$

Similar to start-up and operation constraints, we need equations which take care of shutdown time and inactivity duration. Let the binary variable yf_p denote the period p that the generator turns off after its previous active period given by

$$yf_p = \begin{cases} 1, & \text{if generator shuts down at period } p \\ 0, & \text{otherwise} \end{cases} \qquad 1 \leq p \leq P$$

With this, if the generator shuts down at period p (i.e. yf_p=1), yo_p should be zero for the next γ_{gen} periods. This is given by,

$$ys_p\gamma_{gen} \leq \sum_{p'=p}^{\min[P,p+\gamma_{gen}-1]} 1 - yo_{p'} \qquad 1 \leq p \leq P \tag{11}$$

The generator may want to turn off sometime within planning horizon when less than γ_{gen} periods are left. To enable the system to shut down under such conditions, we have,

$$\sum_{p'=P-\gamma_{gen}+2}^{P} \left(1 - yo_{p'} - ys_{p'}\right) \geq 0 \qquad 1 \leq p \leq P \tag{12}$$

If the operation condition of the generator changes at period p, either the unit has started up (change 0→1) or shut down (change 1→0). This is given by,

$$yo_p - yo_{p-1} = ys_p - yf_p \qquad 1 \leq p \leq P \tag{13}$$

Obviously, a generator cannot start up and shut down at the same time. This is given by,

$$ys_p + yf_p \leq 1 \qquad 1 \leq p \leq P \tag{14}$$

Depending on the inactivity duration (i.e. more than γ_{gen}) a generator might require a hot, warm, or cold start [16]. For obvious reasons, a hot start is the easiest, least-time-consuming, and least-cost approach while a cold start is the most time consuming and costly option.

Consideration of start-up mode requires the program not only to know the start-up/shutdown periods but also the off period duration (fD_p) at period p. For this, we define a counter for off periods duration given by [17]

$$fD_{p-1} + 1 \geq fD_p \qquad 2 \leq p \leq P \qquad (15)$$

Whenever the system starts up $(yo_p = 1)$, the counting should stop. This is formulated by adding a large constant to the right hand side of the above equation. This is given by,

$$fD_{p-1} + 1 \leq fD_p + (BM + 1) \times yo_p \qquad 2 \leq p \leq P \qquad (16)$$

We need also the following equations so that Eqs. 15 and 16 can together force $fD_p = 0$ when $yo_p = 1$.

$$fD_p - BM \times \left(1 - yo_p\right) \leq 0 \qquad 1 \leq p \leq P \qquad (17)$$

The value BM is a big constant value which could be for example equal to the number of planning periods (P) or the maximum allowable off period, etc.

Once, we know the off duration, we are able to identify the type of start-up. We define $M=3$ start-up modes (m: 1 (hot), 2 (warm), and 3 (cold)). Let the binary variable ysm_{pm} denote the period p that the generator starts up at mode m, given by

$$ysm_{pm} = \begin{cases} 1, & \text{if generator starts up at mode } m \\ 0, & \text{otherwise} \end{cases} \qquad 1 \leq p \leq P$$

Obviously, the generator can only turn on at one mode. This is given by,

$$\sum_{m=1}^{M} ysm_{pm} = ys_p \qquad 1 \leq p \leq P \qquad (18)$$

Starting up at a certain mode requires the generator to have been off within a minimum $\left(f_{pm}^{L}\right)$ and maximum $\left(f_{pm}^{U}\right)$ periods of time. These are known parameters of any generator. Obviously, the lower bound of hot start is the minimum off period of the generator, i.e. $f_{p1}^{L} = \gamma_{gen}$. Eq. 18, guarantees that only one start up mode will be selected. However, we need also to ascertain that the right mode is selected based on off period duration. This is given by,

$$\sum_{m=1}^{M} ysm_{(p+1)m} f_{pm}^{U} + M_g \times \left(1 - yo_{p+1}\right) \geq fD_p \qquad 1 \leq p \leq P \qquad (19)$$

$$\sum_{m=1}^{M} ysm_{(p+1)m} f_{pm}^{L} \leq fD_p \qquad 1 \leq p \leq P \qquad (20)$$

Having known the type of start-up, the associated cost can be computed by,

$$SUC_p = \sum_{m=1}^{M} ysm_{pm} SUC_{pm}^{*} \qquad 1 \le p \le P \qquad (21)$$

Where, SUC_{pm}^{*} is startup cost at mode m which is a known parameter. The occurred start-up cost of the generator at time p is SUC_p. The shutdown cost is given by,

$$SDC_p = (yo_{p-1} - yo_p) SDC_p^{*} \qquad 1 \le p \le P \qquad (22)$$

Where, SDC_p^{*} is the known shutdown cost and SDC_p is the occurred shutdown cost during period p.

The generator also has a limitation for ramping up and down from one period to the next period. The ramping values also vary at start-up or shut down with the time that the process is running. At start-up and shutdown, the maximum ramp rates are RU^{*} and RD^{*}, respectively. During operation these values are RU and RD. At any period of time, the generator can operate at its maximum capability i.e. the generatable capacity GC_p^U. However, if it is planned to be shutdown in the following period p+1, some initial actions should be taken to ramp down the load at period p. Therefore, considering start-up/shutdown complexities the maximum generation (G_p^U) at any period p may be in fact less than its generatable capacity GC_p^U. This is given by,

$$G_p^U \le GC_p^U \times (yo_p - yf_{p+1}) + yf_{p+1} \times RD^{*} \qquad 1 \le p \le P \qquad (23)$$

If the generator is operating at the capacity of G_p during period p, its maximum capacity at the following period could be only RU higher than the current value. Or if it is off and starts up in the following period, its capacity can be maximum RU^{*}. these are given by,

$$G_p^U \le G_{p-1} + yo_{p-1} RU + ys_p RU^{*} \qquad 2 \le p \le P \qquad (24)$$

Therefore, the generation capacity, G_p, should be always less than or equal to the maximum generation (G_p^U). This is given by,

$$G_p \le G_p^U \qquad 1 \le p \le P \qquad (25)$$

Similar to ramp up, when a generator ramps down in the following periods, the capacity reduction should be less than RD and if it shuts down, the difference in capacity should be less than RU^{*} (i.e. the capacity at the previous period should not be more than RU^{*}). This is given by,

$$G_{p-1} - G_p \leq yo_p \mathrm{RD} + yf_p RD^* \qquad 2 \leq p \leq P \qquad (26)$$

As discussed earlier, the generator cannot operate below a minimum capacity OC^L. This is given by,

$$G_p \geq yo_p OC^L \qquad 1 \leq p \leq P \qquad (27)$$

The cost of fuel (natural gas) is FC_p per unit of energy consumed. the generator may require a certain amount of fuel for start-up and synchronization with the grid, though still no load is being dispatched to the grid. This so-called operating-non-load fuel consumption is given by ONL which is the fraction of fuel consumption when the generator operates at full capacity. Each generator has a fixed periodical operation and maintenance cost of FOM_p as well as a variable operation and maintenance cost VOM_p per unit of electricity generated. With these, the short run marginal cost (SRMC) of the generator at period p is given by,

$$SRMC_p = FOM_p + VOM_p G_p + SUC_p + SDC_p + yo_p ONLFC_p + G_p FC_p$$

$$1 \leq p \leq P \qquad (28)$$

$$Em_p = \beta F_{CB,p}^{NG} \qquad 1 \leq p \leq P \qquad (29)$$

Carbon intensity of CI_p refers to the amount of CO_{2e} generation per unit of electricity generated at period p. This is given by,

$$CI_p = \frac{Em_p}{G_p^{net}} \qquad 1 \leq p \leq P \qquad (30)$$

This completes the governing equations and constraints. The final requirement is an equation for the objective function which could vary for different goals under diverse market structures. A typical objective could be to maximize the difference between the revenue from electricity sales and the SRMC of the generator over the planning horizon. This objective function is given by,

$$Benefit = \sum_p^P \left(G_p^{net} E_p - SRMC_p \right) \qquad (31)$$

Therefore, this is a mixed integer linear program (MILP) with Eq. 31 as the objective function and Eqs. (1-30) as constraints.

3.2 Storage-integrated gas-fired power plant

The plant's thermodynamics

The schematic of the storage-integrated gas-fired power plant is illustrated in Figure 3b which is obviously more complex than the case without storage. The ambient air to the LP turbine could be for combustion and/or storage system (after further compression). Therefore, the total air flowrate to the LP turbine, during period p, is given by,

$$F^A_{LP,p} = F^A_{LP.CB,p} + F^A_{LP.S,p} \qquad 1 \le p \le P \tag{32}$$

where $F^A_{LP.CB,p}$ and $F^A_{LP.CB,p}$ are the flowrates of air from the LP turbine which are sent to combustion chamber and air storage system, respectively. The energy used for compression of $F^A_{LP,p}$ mass unit of air from pressure of P^A_{LPi} to P^A_{LPo} is:

$$E^A_{LP,p} = \frac{F^A_{LP,p}}{\eta_{LP}} \frac{z^A_{LP} R T^A_{LPi}}{M^A} \frac{k^A_{LP}}{k^A_{LP}-1} \left[\left(\frac{P^A_{LP.o}}{P^A_{LP.i}} \right)^{\frac{k^A_{LP}-1}{k^A_{LP}}} - 1 \right] \qquad 1 \le p \le P \tag{33}$$

where, η_{LP} is the compressor efficiency, R is gas constant, and M^A is air molecular weight. z^A_{LP} and k^A_{LP} are average air compressibility factor and polytropic constant, respectively, for the operating condition of the compressor. The air for storage $\left(F^A_{LP.S,p}\right)$, after being cooled to $T^A_{HP.i}$ is pressurized at HP compressor to the pressure of the storage plus the pressure drop. This is given by,

$$E^A_{HP,p} = \frac{F^A_{LP.S,p}}{\eta_{HP}} \frac{z^A_{HP} R T^A_{HP.i}}{M^A} \frac{k^A_{HP}}{k^A_{HP}-1} \left[\left(\frac{P^A_{HP.o,p}}{P^A_{LP.o}} \right)^{\frac{k^A_{HP}-1}{k^A_{HP}}} - 1 \right] \qquad 1 \le p \le P \tag{34}$$

where, η_{HP} is the HP compressor efficiency, and z^A_{HP} and k^A_{HP} are average air compressibility factor and polytropic constant, respectively, for the operating condition of the compressor. $P^A_{HP.o,p}$ is the outlet pressure of the HP compressor during period p. This pressure varies based on the pressure of the storage system. Here, we define two variables for the operation of storage systems. The first variable is state of capacity (SOC), which is identical to state of charge in electrical energy storage systems with the only difference that here SOC represents the storage systems mass capacity. We also define state of pressure (SOP), which accounts for the storage system's pressure. SOC for air during any period p is given by,

$$SOC_p^A = \sum_{p'=1}^{p} \left(F_{LP.S,p'}^A - F_{S.CB,p'}^A \right) \qquad 1 \le p \le P \qquad (35)$$

For obvious reasons, the SOC is always controlled, during the operation, within a certain upper (SOC_U) and lower (SOC_L) bound. This is given by,

$$SOC_L^A \le SOC_p^A \le SOC_L^A \qquad 1 \le p \le P \qquad (36, 37)$$

SOP follows the gas law (PV=zRT) and is given by,

$$SOP_p^A = \frac{SOC_p^A z_S^A R T_S^A}{M^A V_S^A} \qquad 1 \le p \le P \qquad (38)$$

where, z_S^A , T_S^A, V_S^A are average air compressibility factor for the operating condition, temperature, and volume of the storage system, respectively. Having defined the SOC, and SOP, the value of $P_{HP.o,p}^A$ in Eq. 34 is given by,

$$P_{HP.o,p}^A = SOP_p^A + \Delta P_S^A \qquad 1 \le p \le P \qquad (39)$$

where ΔP_S^A is pressure drop. When the electricity price is high, an optimal flowrate of air is discharged from the storage system to be sent for combustion chamber. However, the high-pressure gas (after pre-heating) is expanded in a turbine to reduce its pressure to that of combustion chamber. The electricity generated as a result of this expansion is given by,

$$E_{TB,p}^A = \eta_{TB}^A F_{S.CB,p}^A \frac{z_{TB}^A R T_{TB,i}^A}{M^A} \frac{k_{TB}^A}{k_{TB}^A - 1} \left[\left(\frac{P_{TB.o}^A}{SOP_p^A - \Delta P_S^A} \right)^{\frac{k_{TB}^A - 1}{k_{TB}^A}} - 1 \right] \qquad 1 \le p \le P \qquad (40)$$

Therefore, the inlet air to the combustion chamber is the summation of the air from the storage system and the LP compressor. This is given by,

$$F_{CB,p}^A = F_{LP.CB,p}^A + F_{S.CB,p}^A \qquad 1 \le p \le P \qquad (41)$$

Similar to Eq. 1, the relationship between NG and air flowrate is given by,

$$F_{CB,p}^A = AFR\, F_{CB,p}^{NG} \qquad 1 \le p \le P \qquad (42)$$

Natural gas purchased from the grid could be used directly in the combustion chamber or sent for storage (after compression). This is given by,

$$F_{G,p}^{NG} = F_{G.CB}^{NG} + F_{G.S}^{NG} \qquad 1 \le p \le P \qquad (43)$$

Natural gas storage system is also managed with two key variables i.e. SOC and SOP given by,

$$SOC_p^{NG} = \sum_{p'=1}^{p}\left(F_{G.S,p'}^{NG} - F_{S.TB,p'}^{NG}\right) \qquad 1 \le p \le P \qquad (44)$$

$$SOP_p^{NG} = \frac{SOC_p^{NG} z_S^{NG} RT_S^{NG}}{M^{NG} V_S^{NG}} \qquad 1 \le p \le P \qquad (45)$$

where, $F_{G.S,p'}^{NG}$ and $F_{S.TB,p'}^{NG}$ are the flowrates of NG sent for storage directly from the grid, and sent to turbine from the storage, respectively. The parameters z_S^{NG}, T_S^{NG}, V_S^{NG} are average NG compressibility factor (for the operating condition), temperature, and volume of the storage system, respectively. The SOC bound is given by,

$$SOC_L^{NG} \le SOC_p^{NG} \le SOC_L^{NG} \qquad 1 \le p \le P \qquad (46, 47)$$

The NG for storage is first pressurized in a compressor before sending for storage. The compression energy is given by

$$E_{CP,p}^{NG} = \frac{F_{G.S,p}^{NG}}{\eta_{CP}^{NG}} \frac{z_{CP}^{NG} RT_G^{NG}}{M^{Ng}} \frac{k_{CP}^{NG}}{k_{CP}^{NG}-1} \left[\left(\frac{SOP_p^{NG}+\Delta P_S^{NG}}{P_G^{NG}}\right)^{\frac{k_{CP}^{NG}-1}{k_{CP}^{NG}}} - 1\right] \qquad 1 \le p \le P \qquad (48)$$

The stored high-pressure NG, when demanded, is expanded to pipeline pressure. The recovered electrical energy due to expansion energy is given by,

$$E_{TB,p}^{NG} = \eta_{TB}^{NG} F_{S.TB,p}^{NG} \frac{z_{TB}^{NG} RT_{TB,i}^{NG}}{M^{NG}} \frac{k_{TB}^{NG}}{k_{TB}^{NG}-1} \left[\left(\frac{P_G^{NG}}{SOP_p^{NG}-\Delta P_S^{NG}}\right)^{\frac{k_{TB}^{NG}-1}{k_{TB}^{NG}}} - 1\right] \qquad 1 \le p \le P \qquad (49)$$

Given the market condition, the stored NG is discharged for resale to the grid, for local use, or both. This is given by,

$$F_{S.TB,p}^{NG} = F_{S.G,p}^{NG} + F_{S.CB,p}^{NG} \qquad 1 \le p \le P \qquad (50)$$

Given the design size of the NG turbine ($F_{S.TB}^{NG*}$), the combined flows of NG to the grid and combustion chamber are limited by the turbine capacity. This is given by,

$$F_{S.TB,p}^{NG} = F_{S.G,p}^{NG} + F_{S.CB,p}^{NG} \le F_{S.TB}^{NG*} \qquad 1 \le p \le P \qquad (51)$$

A typical size of NG turbine could be double size of NG compressor, as at some conditions it may concurrently supply NG to combustion and also sell to the grid.

The mass balance around the NG for combustion requires that the flowrate of NG to combustion chamber equals the combined flowrates of NG from the storage (to combustion) and from the grid (to combustion). This is given by,

$$F_{CB,p}^{NG} = F_{S.CB,p}^{NG} + F_{G.CB,p}^{NG} \qquad 1 \le p \le P \qquad (52)$$

The combustion product is a high-temperature and high-pressure flue gas which based on conservation of mass has flowrate of F_p^{FG},

$$F_p^{FG} = F_{CB,p}^{A} + F_{CB,p}^{NG} \qquad 1 \le p \le P \qquad (53)$$

The flue gas is directed to expansion turbine and generates electricity with the rate of,

$$E_{TB,p}^{FG} = \eta_{TB}^{FG} F_p^{FG} \frac{z_{TB}^{FG} R T_{TB,i}^{FG}}{M^{FG}} \frac{k_{TB}^{FG}}{k_{TB}^{FG}-1} \left[\left(\frac{P_{TBo}^{FG}}{P_{TBi}^{FG}} \right)^{\frac{k_{TB}^{FG}-1}{k_{TB}^{FG}}} - 1 \right] \qquad 1 \le p \le P \qquad (54)$$

where, η_{TB}^{FG} is the FG turbine efficiency, and M^{FG} is FG molecular weight. z_{TB}^{FG} and k_{TB}^{FG} are average FG compressibility factor and polytropic constant, respectively, for the operating condition of the turbine. $T_{TB,i}^{FG}$ is the flue gas temperature right after combustion at the inlet of the turbine.

The gross power of the plant is the difference of turbines' and compressors' power given by,

$$G_p^G = \left(E_{LP,p}^{A} + E_{HP,p}^{A} + E_{CP,p}^{NG} \right) - \left(E_{TB,p}^{FG} + E_{TB,p}^{A} + E_{TB,p}^{NG} \right) \qquad 1 \le p \le P \qquad (55)$$

A small fraction of this power is used locally for auxiliary units (Aux) and the remainder, called net power, is exported to the grid,

$$G_p = (1 - Aux) G_p^G \qquad 1 \le p \le P \qquad (56)$$

The maximum generatable capacity GC_p^U of the storage-integrated system is therefore in a condition when LP and HP compressors are off and air is fully supplied from the storage system. Furthermore, natural gas is not being stored (and thus NG compressor is off). Under this condition, we have

$$GC_p^U = -\left(E_{TB}^{FG*} + E_{TB}^{A*} + E_{TB}^{NG*} \right) \cong -\left(E_{TB}^{FG*} + E_{TB}^{A*} \right) \qquad 1 \le p \le P \qquad (57)$$

where, E_{TB}^{FG*}, E_{LP}^{A*}, and E_{TB}^{NG*} are design capacities of flue gas turbine, air compressor, and NG compressor, respectively. Therefore, the power output ratio (*PR*) of the generation with storage vs the one without storage is given by,

$$PR = \frac{E_{TB}^{FG*} + E_{TB}^{A*} + E_{TB}^{NG*}}{E_{TB}^{FG*} - E_{LP}^{A*}} \tag{58}$$

The plant's scheduling

The operation of a gas generator with air/gas storage is complex not only in the thermodynamics of the process, but also from an economic perspective as the storage facility provides a higher degree of freedom for the company to influence the market price fluctuations. In the previous scenario, without storage, the generator was either on or off. But, here, the air compression system could be off while the combustion system is on and vice versa. Therefore, further to previous scheduling variables, we will need other variables to manage the operation of the new process. The followings are the list of equations that will be used here.

$$F_{CB,p}^{A} \leq yo_p \, F^{A*} \qquad 1 \leq p \leq P \tag{59}$$

$$ys_p \alpha_{gen} \leq \sum_{p'=p}^{\min[P,\, p+\alpha_{gen}-1]} yo_{p'} \qquad 1 \leq p \leq P \tag{60}$$

$$\sum_{p'=P-\alpha_{gen}+2}^{P} \left(yo_{p'} - ys_{p'} \right) \geq 0 \qquad 1 \leq p \leq P \tag{61}$$

$$ys_p \gamma_{gen} \leq \sum_{p'=p}^{\min[P,\, p+\gamma_{gen}-1]} 1 - yo_{p'} \qquad 1 \leq p \leq P \tag{62}$$

$$\sum_{p'=P-\gamma_{gen}+2}^{P} \left(1 - yo_{p'} - ys_{p'} \right) \geq 0 \qquad 1 \leq p \leq P \tag{63}$$

$$yo_p - yo_{p-1} = ys_p - yf_p \qquad 1 \leq p \leq P \tag{64}$$

$$ys_p + yf_p \leq 1 \qquad 1 \leq p \leq P \tag{65}$$

$$fD_{p-1} + 1 \geq fD_p \qquad 2 \leq p \leq P \tag{66}$$

$$fD_{p-1} + 1 \leq fD_p + (BM + 1) \times yo_p \qquad 2 \leq p \leq P \tag{67}$$

$$fD_p - BM \times \left(1 - yo_p \right) \leq 0 \qquad 1 \leq p \leq P \tag{68}$$

$$\sum_{m=1}^{M} ysm_{pm} = ys_p \qquad 1 \le p \le P \qquad (69)$$

$$\sum_{m=1}^{M} ysm_{(p+1)m} Of_{pm}^{U} + BM \times (1 - yo_{p+1}) \ge fD_p \qquad 1 \le p \le P \qquad (70)$$

$$\sum_{m=1}^{M} ysm_{(p+1)m} f_{pm}^{L} \le fD_p \qquad 1 \le p \le P \qquad (71)$$

$$SUC_p = \sum_{m=1}^{M} ysm_{pm} SUC_{pm}^{*} \qquad 1 \le p \le P \qquad (72)$$

$$SDC_p = \left(yo_{p-1} - yo_p\right) SDC_p^{*} \qquad 1 \le p \le P \qquad (73)$$

$$G_p^U \le GC_p^U \times (yo_p - yf_{p+1}) + yf_{p+1} \times RD^{*} \qquad 1 \le p \le P \qquad (74)$$

$$G_p^U \le G_{p-1} + yo_{p-1} RU + ys_p RU^{*} \qquad 2 \le p \le P \qquad (75)$$

$$G_p \le G_p^U \qquad 1 \le p \le P \qquad (76)$$

$$G_{p-1} - G_p \le yo_p \mathrm{RD} + yf_p RD^{*} \qquad 2 \le p \le P \qquad (77)$$

$$G_p \ge yo_p OC^L \qquad 1 \le p \le P \qquad (78)$$

$$SRMC_p = FOM_p + VOM_p G_p + SUC_p + SDC_p + yo_p ONLFC_p + G_p FC_p \qquad 1 \le p \le P \qquad (79)$$

$$Em_p = \beta F_{CB,p}^{NG} \qquad 1 \le p \le P \qquad (80)$$

$$CI_p = \frac{Em_p}{G_p^{net}} \qquad 1 \le p \le P \qquad (81)$$

Further to these equations, we define the following binary variable for air compression system at period p:

$$yA_p = \begin{cases} 1, & \text{if air compression system is operating during period } p \\ 0, & \text{otherwise} \end{cases} \qquad 1 \le p \le P$$

This allows us to place a constraint on the air flowrate to the compression system:

$$F_{LP,p}^{A} \le F^{A*} yA_p \qquad 1 \le p \le P \qquad (82)$$

For tracking the operation periods of air compression activity, we need to track the periods that the air compression system starts up or shuts down. Let the binary variable ysA_p denote the period p that the air compressor starts up after its previous off period given by

$$ysA_p = \begin{cases} 1, & \text{if air compressor starts up at period } p \\ 0, & \text{otherwise} \end{cases} \qquad 1 \le p \le P$$

Therefore, given the ramp up/down limitations, if the generator starts up at period p (i.e. ysA_p=1), yA_p should be on for the next α_A periods. This is given by,

$$ysA_p\alpha_A \le \sum_{p'=p}^{\min[P,p+\alpha_A-1]} yA_{p'} \qquad 1 \le p \le P \tag{83}$$

$$\sum_{p'=P-\alpha_A+2}^{P} \left(yA_{p'} - ysA_{p'}\right) \ge 0 \qquad 1 \le p \le P \tag{84}$$

Similar to start-up and operation constraints, we need equations which represent of shutdown time and inactivity duration. Let the binary variable yfA_p denote the period p that the compressor turns off after its previous active period given by

$$yfA_p = \begin{cases} 1, & \text{if air compressor shuts down at period } p \\ 0, & \text{otherwise} \end{cases} \qquad 1 \le p \le P$$

With this, if the compressor shuts down at period p (i.e. yfA_p=1), yA_p should be zero for the next γ_A periods. This is given by,

$$ysA_p\gamma_A \le \sum_{p'=p}^{\min[P,p+\gamma_A-1]} 1 - yA_{p'} \qquad 1 \le p \le P \tag{85}$$

$$\sum_{p'=P-\gamma_A+2}^{P} \left(1 - yA_{p'} - ysA_{p'}\right) \ge 0 \qquad 1 \le p \le P \tag{86}$$

If the operating condition of compressor changes at period p, either the unit has started up (change 0→1) or shut down (change 1→0). This is given by,

$$yA_p - yA_{p-1} = ysA_p - yfA_p \qquad 1 \le p \le P \tag{87}$$

Obviously, a generator cannot start up and shut down at the same time. This is given by,

$$ysA_p + yfA_p \le 1 \qquad 1 \le p \le P \tag{88}$$

Air cannot be stored at the same time when it is being discharged. We define the following binary variable for air storage at period p:

$$yAS_p = \begin{cases} 1, & \text{if air is being stored during period } p \\ 0, & \text{otherwise} \end{cases} \qquad 1 \le p \le P$$

We can then write either a charge or discharge constraint,

$$F^{A}_{S.CB,p} \le yAS_pF^{A*} \qquad 1 \le p \le P \tag{89}$$

$$F^{A}_{LP.S,p} \le \left(1 - yAS_p\right)F^{A*} \qquad 1 \le p \le P \tag{90}$$

Likewise, NG at any period p NG can be either purchased or sold. For this, we define the following binary variable for NG:

$$yNG_p = \begin{cases} 1, & \text{if NG is purchased during period } p \\ 0, & \text{otherwise} \end{cases} \qquad 1 \le p \le P$$

Now, we can constrain the NG with,

$$F_{G,p}^{NG} \le yNG_p F_G^{NG*} \qquad 1 \le p \le P \tag{91}$$

$$F_{S.G,p}^{NG} \le \left(1 - yNG_p\right) F_G^{NG*} \qquad 1 \le p \le P \tag{92}$$

With these the objective function can be computed which is the difference between the revenue from electricity sales and the SRMC of the generator over the planning horizon. This is given by,

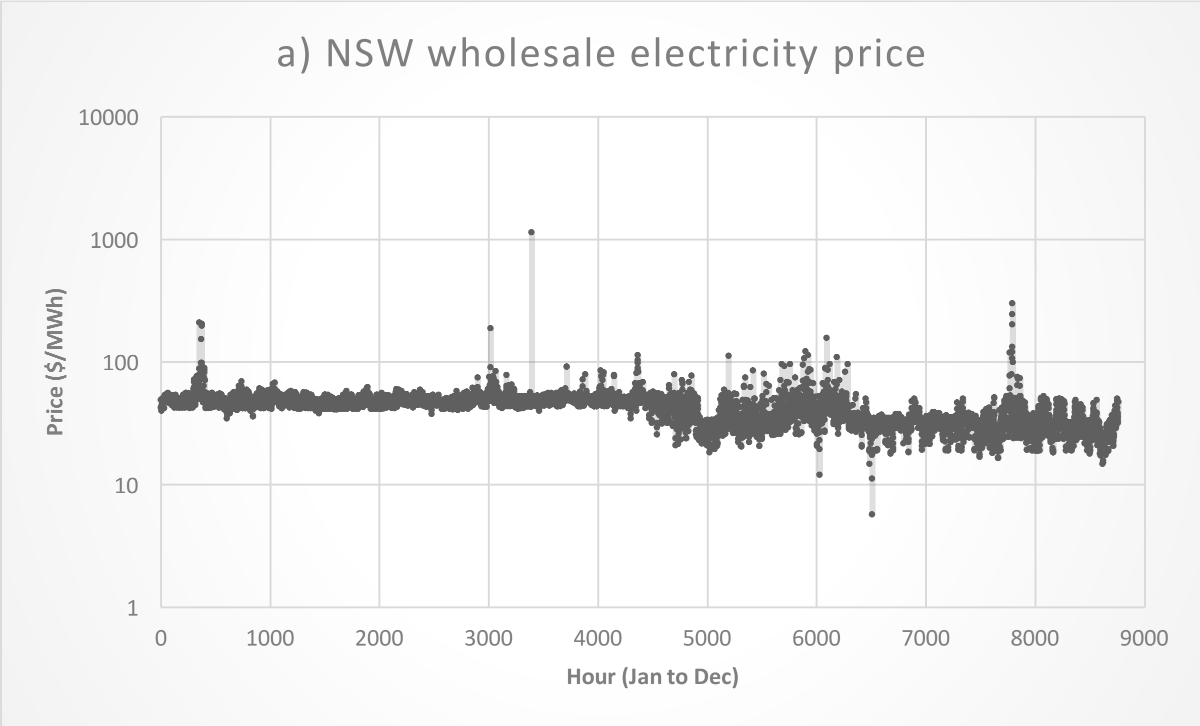
$$Benefit = \sum_p^P \left(G_p^{net} E_p - SRMC_p\right) \tag{93}$$

Therefore, this model consists of Eq. 93 as the objective function to be maximized and Eqs. (32-92) as constraints. In four equations for compressor or expander power (i.e. Eqs. 34, 40, 48, and 49), there are nonlinear terms which make the problem an MINLP. It is also possible to linearize these equations and convert the model into an MILP. Among a few possible linearization approaches, we have presented one method in the appendix which is combination of linear curve fitting and the McCormick envelopes [18].

4 Case studies

4.1 Example 1

An open cycle gas generator, in the state of New South Wales, Australia, generates 180 MW power at full load. The generator uses 33.2 tonnes/h of natural gas with a high heating value of 55 GJ/tonne (1826 GJ/h) at pipeline pressure of 40 bars. For combustion, 1106.8 tonnes/h of ambient air is pressurized to 40 bars in a compressor with 146.5 MW power demand. The combustion flue gas is expanded in a turbine to 1.05 bar and generates 326.5 MW gross electricity with negligible auxiliary electricity. The projected electricity and NG prices of the market are shown in Figure 5a and Figure 5b (which are actually real values of 2014).



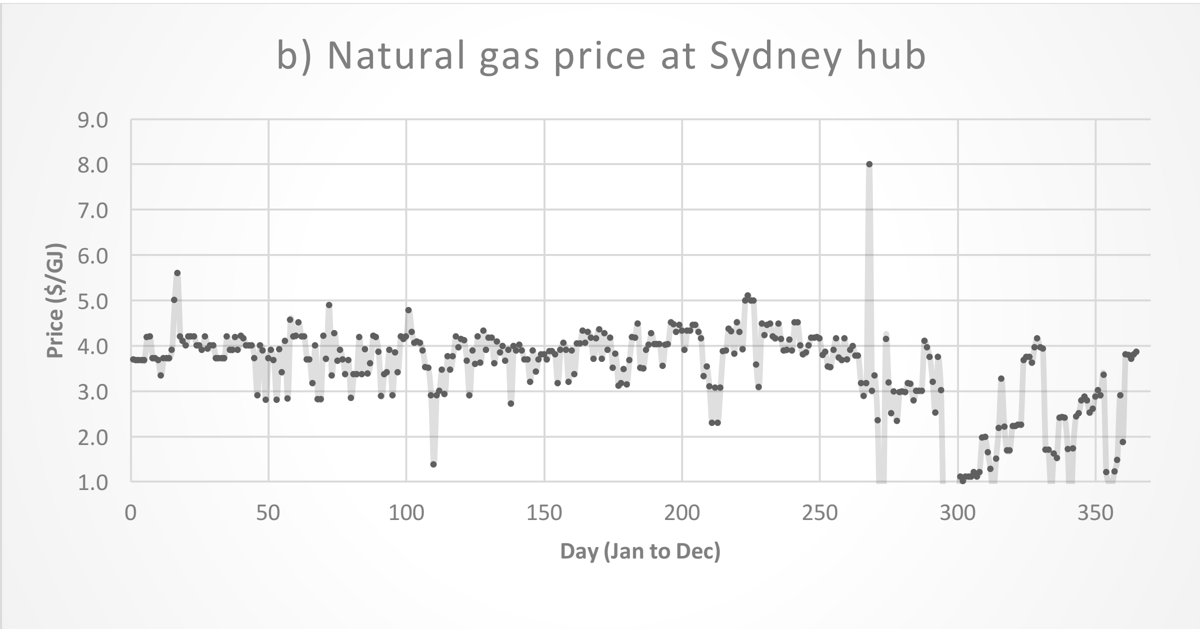


Figure 5: Projected market electricity (a) and natural gas (b) prices during Jan-Dec (real values of 2014 in NSW, Australia)

The objective is to study two scenarios; in Scenario 1, we aim to develop an optimal schedule for the operation of the generator so that it results in the highest transaction benefit with the two networks (NG and electricity). In the Scenario 2, however, we assess the condition that the company has installed two storage systems each with a capacity of 50,000 m^3. The minimum and maximum SOP for both air and gas storage systems are 45 and 150 bar, respectively. Again we are looking for an optimal schedule for the operation of the plant with the highest economic benefit. The technical parameters for the two power plant designs are given in Table 1. The maximum generation capacity of the plant for Scenario 1 is 180 MW while it is 385.6 MW for Scenario 2. This translates to a power output ratio of *PR*=2.14.

Table 1: Technical parameters of generator with and without storage (Thermodynamic values from Aspen Hysys)

Component	Without storage	With storage
Air		
Mol. Weight	28.85	〃
Std. density (kg/m3)	1.179	〃
NG		
Mol. weight	16.61	〃
HHV (MJ/kg)	55.0	〃
Air LP Compressor		
Design pressure range (bar)	1→40 (three stages)	〃
design power (MW)	146.5	〃
design flowrate (tonne/h)	1106.8	〃
Isentropic efficiency (%)	85	〃
Avg. gas compressibility factor	1.004	〃
Avg. polytropic constant	1.396	〃
Air HP Compressor		
Design pressure range (bar)	-	40-160
design power (MW)	-	59.3
design flowrate (tonne/h)	-	1106.8
Isentropic efficiency (%)	-	86.5
Avg. gas compressibility factor	-	1.039
Avg. polytropic constant	-	1.435
Air Turbine		
Design pressure range (bar)	-	150-40
design power (MW)	-	55.9
design flowrate (tonne/h)	-	1106.8
Isentropic efficiency (%)	-	86.7
Avg. gas compressibility factor	-	1.041
Avg. polytropic constant	-	1.388
NG Compressor		
Design pressure range (bar)	-	40-160
design power (MW)	-	2.7
design flowrate (tonne/h)	-	33.2
Isentropic efficiency (%)	-	84.0
Avg. gas compressibility factor	-	0.964
Avg. polytropic constant	-	1.406
NG Turbine		
Design pressure range (bar)	-	150-40
design power (MW)	-	2*1.7
design flowrate (tonne/h)	-	2*33.2
Isentropic efficiency (%)	-	89.0
Avg. gas compressibility factor	-	0.964
Avg. polytropic constant	-	1.406
Flue gas Turbine		
Design pressure range (bar)	40→1 (two stages)	〃
design power (MW)	326.3	〃
design flowrate (tonne/h)	1140	〃
Isentropic efficiency (%)	85	〃
Avg. gas compressibility factor	1.002	〃
Avg. polytropic constant	1.305	〃

Air storage system		
Volume (m3)	-	50000
pressure range (bar)	-	45-150
	-	
NG storage system		
Volume (m3)	-	50000
pressure range (bar)	-	45-150
	-	
Maximum possible power generation (MW)	180	385.6

All problems are formulated in GAMS using the MIP solver CPLEX 12.4.0.1. The execution of the models without storage is very fast. However, storage-integrated models take longer time and most cases we tried required a HPC system. As such, the models without storage are executed on a desktop with a 1.80 GHz Intel Core Processor and 8 GB RAM. The storage-integrated models are however submitted to a HPC system with request of 200 GB Ram and 300 hr of walltime. All problems are executed in two half-yearly segments (Jan-Jun and Jul-Dec). We found relative gap of RG=0.05 the most practical value to use uniformly across all problems as with values lower than this, some problems required very high walltime.

The model without storage contains 118,261 equations, 87,601single variables, and 26,280 discrete variables. The execution time was 20.64 s for Jan-Jun case and 20.87 for Jul-Dec case. The details of the execution results are provided in Table A1 of the appendix. The optimisation model yields the operation schedule of the base-case generator as per Figure 6. Under this condition, the transaction revenue (sales to electricity network – purchases from NG network) of the company is \$9.31M and \$5.8M over the first and second half of the year, respectively. In total, the company's transaction revenue will be \$15.11M over the year (8760 hours).

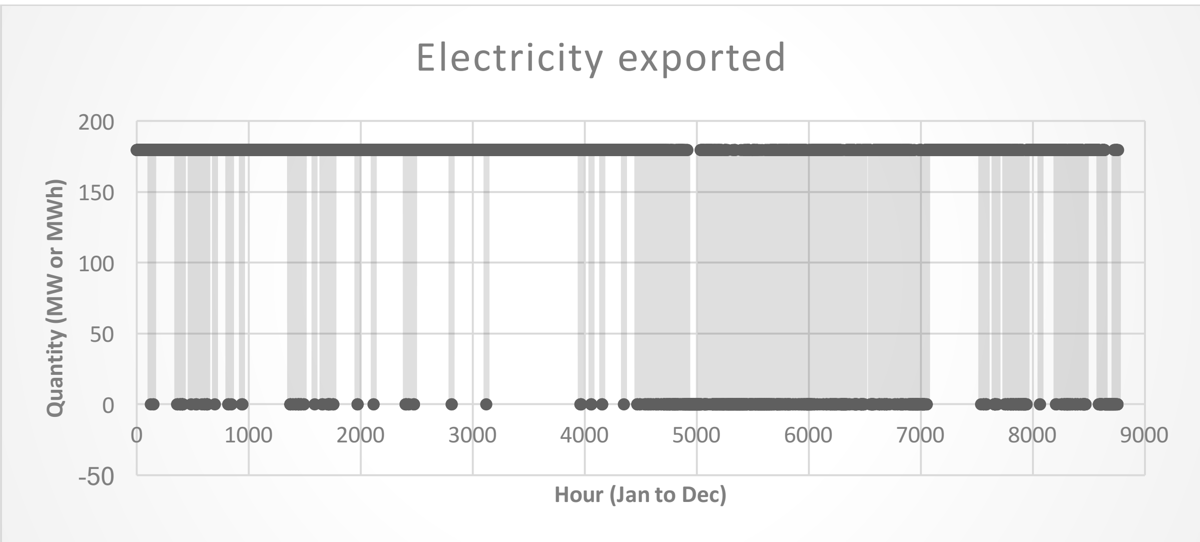
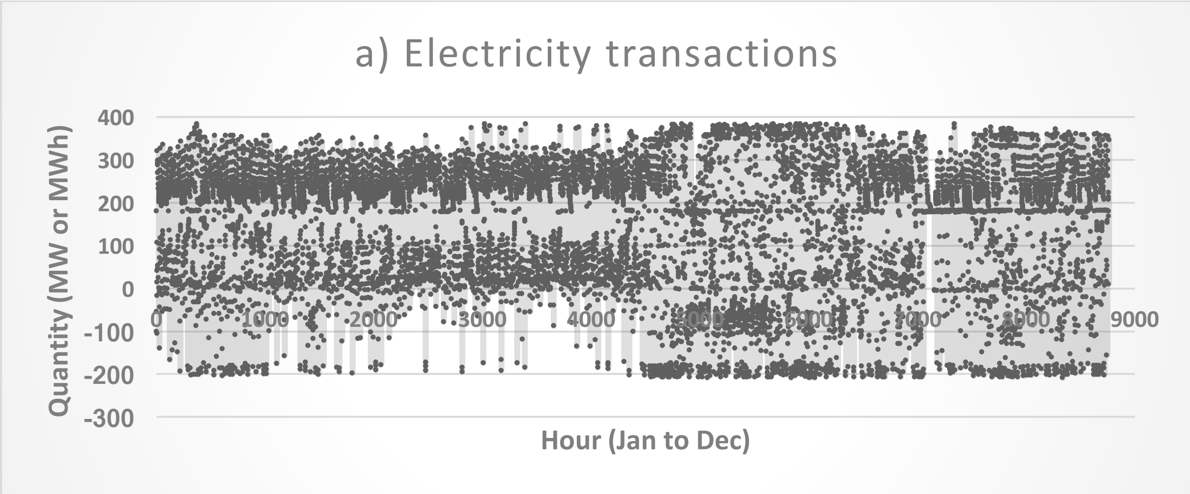


Figure 6: Optimal operation of the base-case generator in response to NSW market

The model with storage is obviously larger, containing 324,121 equations, 205,861 single variables, and 52,560 discrete variables. This problem took 14.44 s and 12.80 s on the HPC system for the first and second half of the year, respectively. With the storage systems the power generation schedule of the plant is as per Figure 7. The storage facility offers flexibility for the company and its transaction revenue increases across the year. The results show that the transaction revenue for the first half of the year is $14.14M (51.8% higher than when without storage) where it is $11.96M (106.2% higher than when without storage). In total, the storage facility increases the company's annual transaction revenue by 72.7% from $15.11 when without storage to $26.10M.

The optimal operation schedule of the storage-integrated generator shows that uring several perios the plant operates at its maximum power generation capability, i.e. 385.6 MW which is more than double of that without storage (180 MW). The figure also shows periods in which the power generation value is -208.5 MW. These are periods that the plant does not generate electricity; rather it uses the low-value electricity of the grid and runs the compressors for air and/or NG compression and storage. The profile of NG transaction (Figure 7b) also carries some insights. Based on power plant base design, the maximum NG flow to the combustion chamber is 1826 GJ/h, while the transaction values are higher than this (upto double) in several periods. This implies the periods that the NG price of the market is low, and it is economical for the company to purchase extra NG and store for later use or for resell. The figure also shows that NG transaction values are never below zero. This implies that under the projected market prices, the self-consumption of the stored NG is prefered to resell.



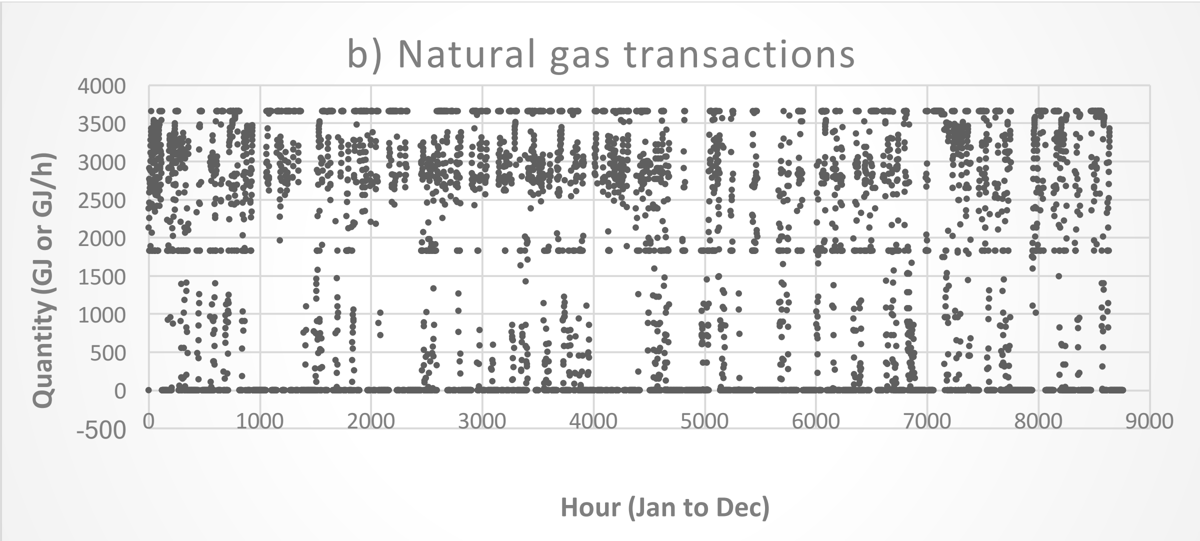


Figure 7: Optimal transactions with the grid with the storage-integrated generator; (a) electricity transactions, and (b) NG transactions

The operation schedule of the storage system is also shown in Figure 8a-d. For each storage system, NG and air, both the SOC and the SOP profiles are shown. The profiles clearly show the fluctuations of the storage systems capacity between the minimum and maximum values i.e. pressure range of 45-150 bar. This pressure range translates to natural gas quantity range of 1390-4636 tonnes and air quantity range of 2416-8053 tonnes. An interesting observation of these figures is that the storage cycles for air are much more than that for NG. The NG storage cycles (Figure 8a-b) are identical to 33.2 full cycles (from minimum SOP to maximum SOP) while the value for air (Figure 8c-d) is 365.9. Does this mean that air storage is more economical than air? We will examine this question in Example 3.

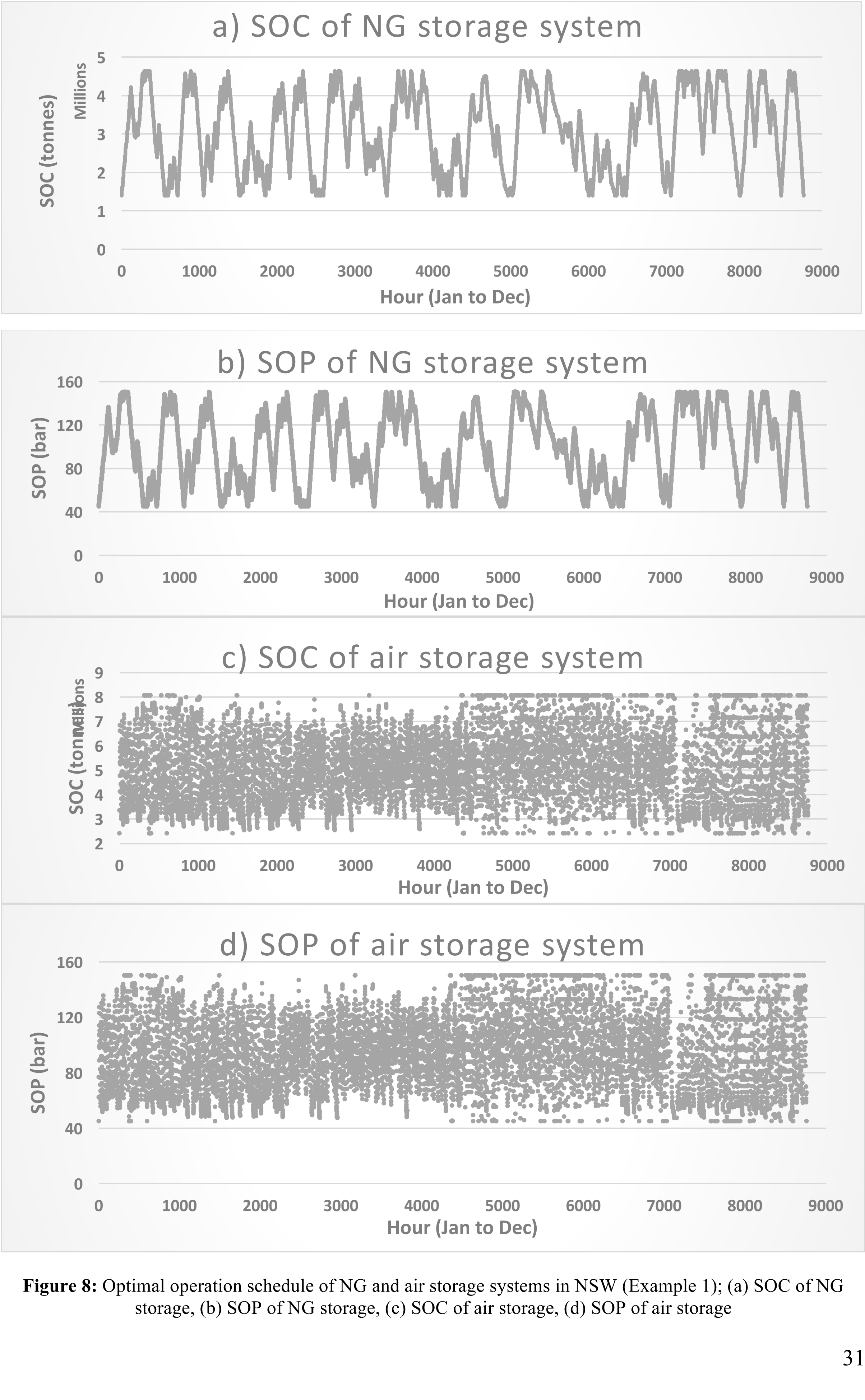


Figure 8: Optimal operation schedule of NG and air storage systems in NSW (Example 1); (a) SOC of NG storage, (b) SOP of NG storage, (c) SOC of air storage, (d) SOP of air storage

4.2 Example 2

Consider the same problem of Example 1, with a difference that the generator is located in the state of Victoria instead of NSW. The Victoria gas market operates differently, and unlike the Sydney hub, with one daily price for NG, it has five prices per day set at 6 am, 10, am, 2 pm, 6 pm, and 10 pm. The projected electricity and NG prices of the Victorian market are shown in Figure 9 (which are actually real values of 2014). The electricity price of Victoria, with the logarithmic axis, implies the higher price volatility compared with what we saw for NSW in Example 1.

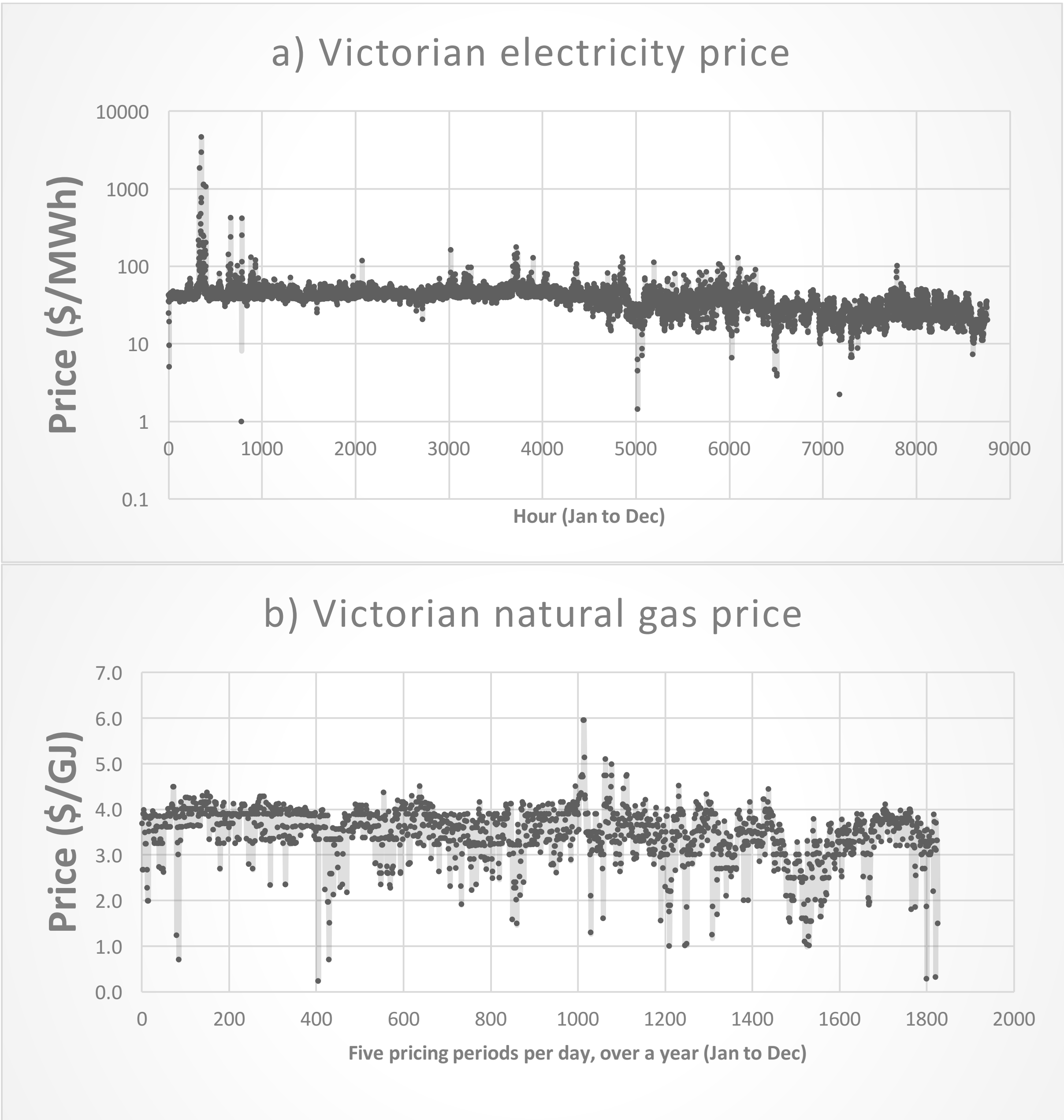


Figure 9: Projected market (a) electricity and (b) natural gas prices during Jan-Dec (real values of 2014 in Victoria, Australia)

This example is also executed for two scenarios with and without storage systems where all parameters were similar to Example 1. The sizes of the problems were the same as the previous example. The execution time of the model without storage (base-case) was 20.61 s and 20.78 s for the first half and second half of the year, respectively (See Table A1 for other details). The optimal operation schedule of generator without storage is shown in Figure 10. The transaction revenue of the company is \$12.04M and \$2.66M over the first and second half of the year, respectively. In total, the company's transaction revenue will be \$14.70M over the year (8760 hours) which is close to that of NSW in Example 1 (\$15.11M).

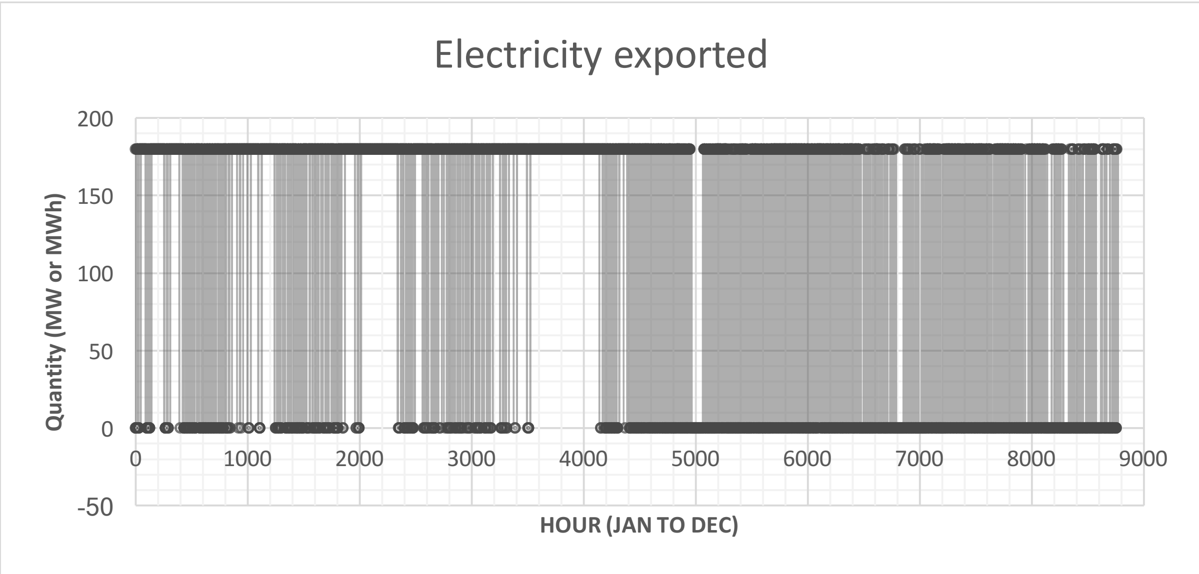


Figure 10: Optimal operation of the base-case generator in response to Victorian market

With 50,000 m^3 air and 50,000 m^3 NG storage systems, the operation schedule of the plant becomes as per Figure 11. This problem took 12.70 s and 12.70 s on the HPC system for the first and second half of the year, respectively. The results show that the transaction revenue for the first half of the year is \$20.93M (73.9% higher than when without storage) and it is \$8.58M (222.6% higher than when without storage). In total, the storage facility increases the company's annual transaction revenue by 100.8% from \$14.70 when without storage to \$29.51M.

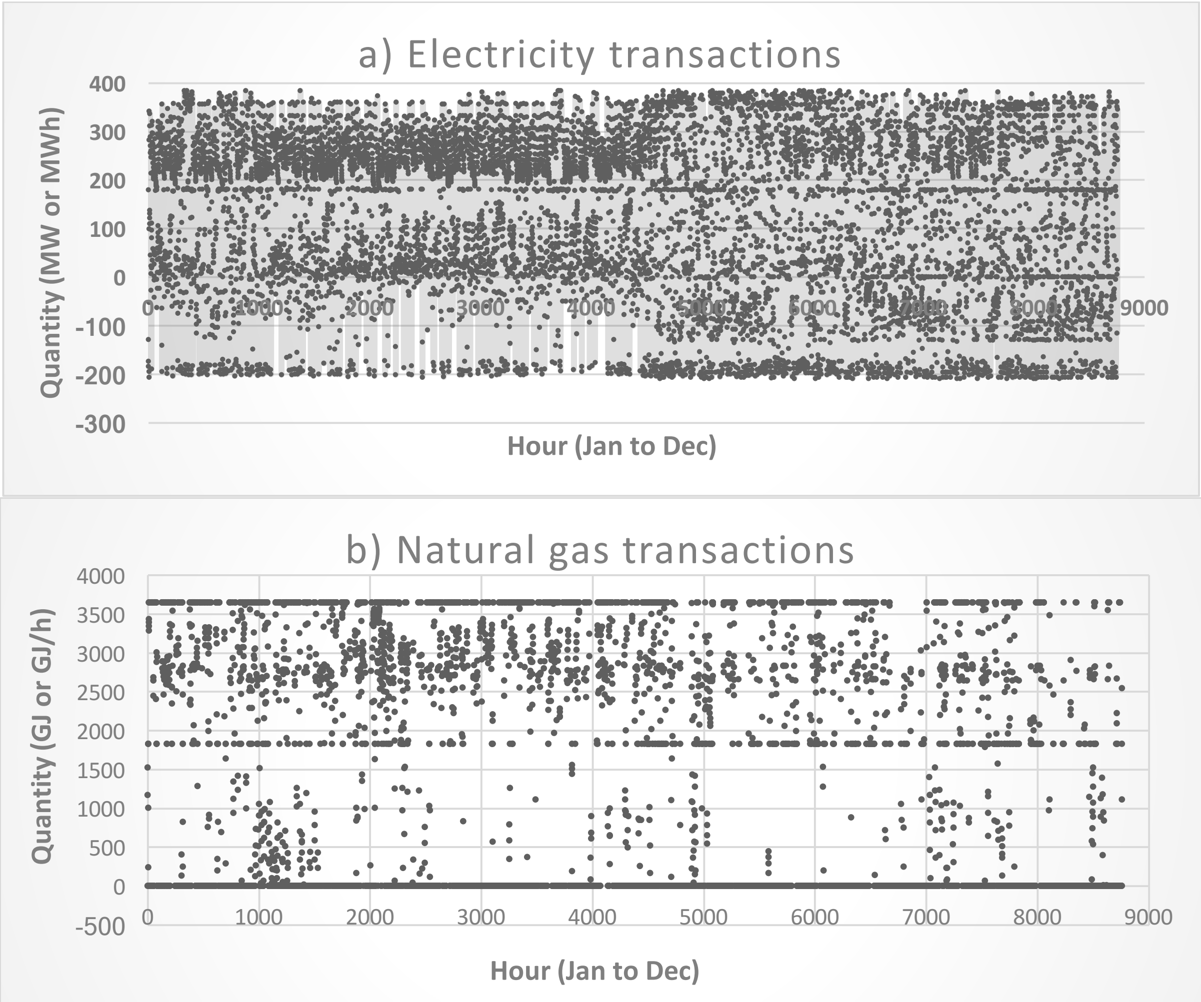


Figure 11: Optimal transactions with the grid with the storage-integrated generator: (a) electricity transactions; (b) NG transactions

The operation schedule of the storage systems in Victoria are also shown in Figure 12. The NG storage cycles for the Victorian market are identical to 32.0 full cycles while the value for air is 400.6. The air storage cycle for Victoria is 9.5% higher than that for NSW (400.6 vs 365.9). The reason for this difference could be sought in the price volatility of the two markets. The mean and standard deviations (STD) of NG prices per GJ for both markets are close. They are \$3.45 (mean) and \$1.02 (STD) for NSW, and \$3.45 (mean) and \$0.63 (STD) for Victoria. However, as also evident from a comparison of Figure 5 and Figure 9 the volatility, and thus the STD for Victoria, is very high. The mean and STD values for NSW are \$42.8 and \$17.1, respectively, while they are \$41.6 and \$67.8 for Victoria. Therefore, it is this high STD of \$67.8 which makes the storage, especially air, more attractive than NSW. As such, while for NSW the transaction revenue was improved by 72.7% from \$15.11M to \$26.10M, the same plant increases the revenue from \$14.70M to \$29.51M, i.e. 100.8% in Victoria. This implies the importance of the volatile market in the attractiveness of energy storage. It is critical to note that the price data are used from current electricity market with little renewable energy penetration. It is expected that with higher renewable energy penetration, especially the wind and solar, the price volatility and thus the attractiveness of storage system will further increase.

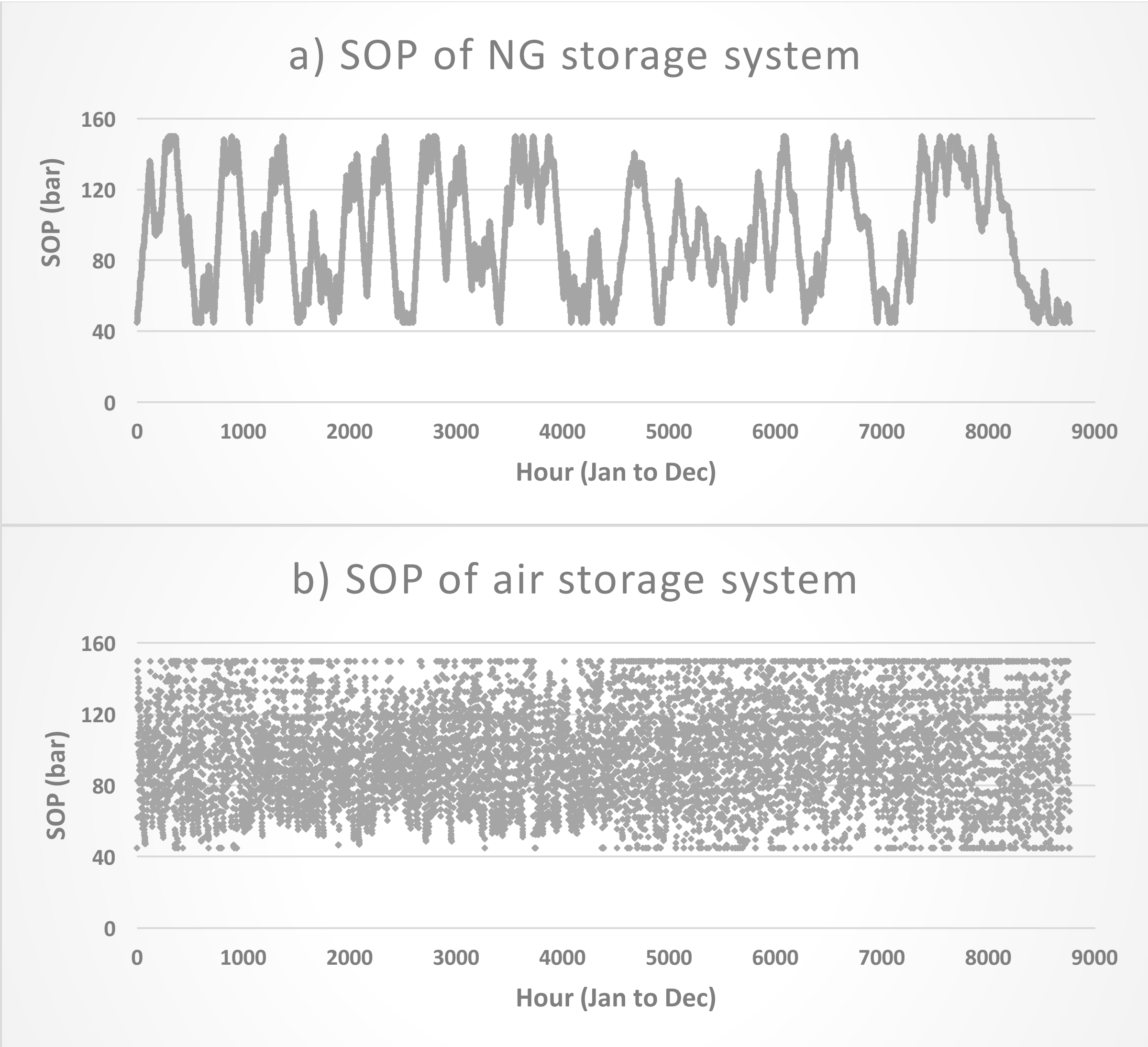


Figure 12: Optimal operation schedule of NG and air storage systems in Victoria (Example 2); (a) SOP of NG storage, (b) SOP of air storage

4.3 Example 3

Following the previous examples, one legitimate question might be the relative economic attractiveness of air and NG storage. One might ponder what would happen if the entire storage capacity is allocated for one type of storage, either air or NG. We study this research question here. All techno-economic parameters are similar to Example 1 and 2, except that here the total storage capacity is 50,000 m^3. We then consider six different cases as per Table 2

Table 2: Six different cases for air and NG storage system sizes

Case No	Air storage size (m^3)	NG storage size (m^3)	Total storage size (m^3)
1	0	50000	50000
2	30000	20000	50000
3	40000	10000	50000
4	50000	0	50000

The optimization program is executed for each of the four cases, at NSW and Victoria markets, and the results are shown in Figure 13 (execution summary in Table A1). It is evident from the figure that both of the storage options are able to improve the revenue of the company in the absence of the other. For instance, Case 1 represents the scenario of having only NG storage, for which the transaction revenues are \$20.3M (NSW), and \$19.8M (Vic). The other extreme is Case 4 with only air storage with revenues of \$21.1M (NSW) and \$24.7M (Vic). As evident also from the figure, there is an optimal mix of storage sizes at which the maximum revenue is achievable. For NSW, the maximum occurs with Case 2 which comprises of 30,000 m^3 of air and 20,000 m^3 of NG storage. For Victoria, however, the best scenario is 40,000 m^3 of air and 10,000 m^3 of NG (Case 3), which is again an implication of the critical role of air storage in addressing Victorian volatile electricity prices.

Therefore, we can conclude that both storage systems have a positive impact on the economics of the plant, and that there is an optimal combination, under any given conditions, which can lead to the highest economic benefits.

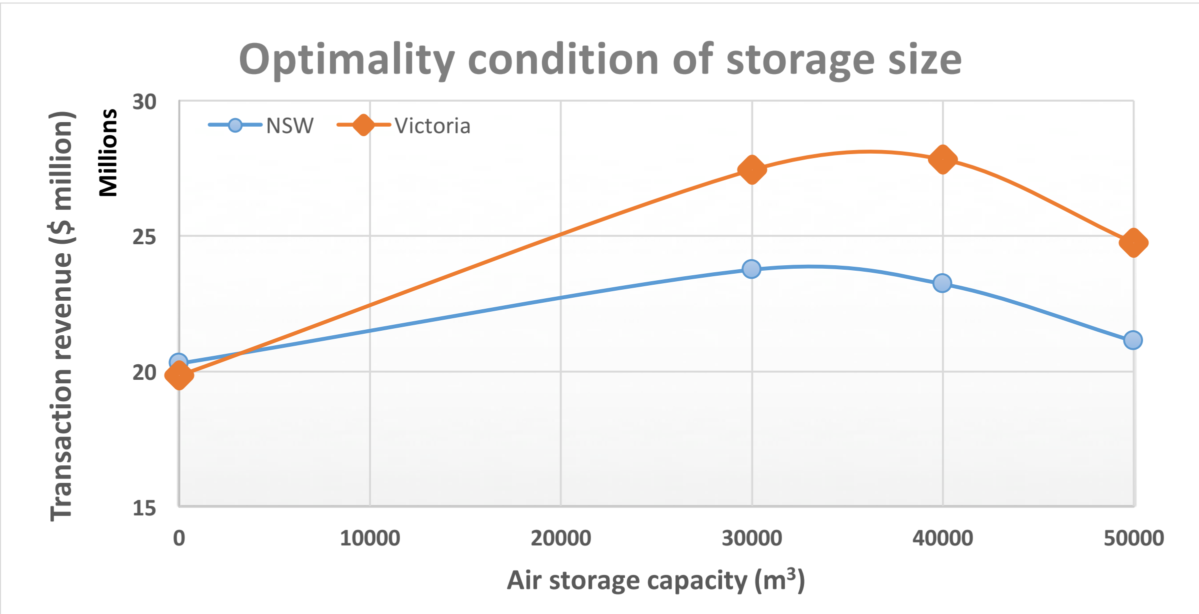


Figure 13: Impact of six different air/NG storage systems sizes on the company's revenue over the planning horizon

5 Conclusion

Compressed air energy storage (CAES) is an energy storage option with a history of almost half a century. The concept of CAES is around the integration of this system with a gas-fired power generator. Here, we have introduced a methodology that a gas power generating plant could install both air and natural gas storage system to utilize their stored energy as well as the real value of natural gas following market dynamics. We have presented a detailed techno-economic formulation for operation scheduling of such a system. We have also presented an example for a 180 MW gas generator in Australia and have shown how the storage facilities could improve the revenues of the plant.

Appendix A: Problem linearization

The storage-integrated gas power plant model is an MINLP due to four nonlinear equations (i.e. Eqs. 34, 40, 48, and 49) for compressor/expander power. Hence, the model could be either solved with MINLP solvers or these nonlinear equations can be linearized. For the case-studies presented in this paper, we have taken the latter approach. Among the several possible linearization approaches, we have used combination of curve fitting and McCormick envelopes [18]. Here, we present the methodology for the high pressure air compressor (Eq. 34). The power formula for HP compressor of air is given by,

$$E^{A}_{HP,p} = \frac{F^{A}_{LP.S,p}}{\eta_{HP}} \frac{z^{A}_{HP} R T^{A}_{HP.i}}{M^{A}} \frac{k^{A}_{HP}}{k^{A}_{HP}-1} \left[\left(\frac{P^{A}_{HP.o,p}}{P^{A}_{LP.o}} \right)^{\frac{k^{A}_{HP}-1}{k^{A}_{HP}}} - 1 \right] \quad 1 \leq p \leq P \tag{34}$$

where, the nonlearity comes from the $F^{A}_{LP.S,p}$, flowrate of air at period p, and $P^{A}_{HP.o,p}$, the outlet pressure of the air period p. We do the linearization at two step:

Step A: linearize the power function term

Given the design inlet and outlet pressures of the compressor, it is possible to fit the term $\left(\frac{P^{A}_{HP.o,p}}{P^{A}_{LP.o}} \right)^{\frac{k^{A}_{HP}-1}{k^{A}_{HP}}}$ to a linear function $a_{HP} P^{A}_{HP.o,p} + b_{HP}$. It is noteworthy that in most of the compressor cases we studied for this paper, the fits had reasonably good accuracy (R^2>0.98). With this, the equation becomes,

$$E^{A}_{HP,p} = \frac{F^{A}_{LP.S,p}}{\eta_{HP}} \frac{z^{A}_{HP} R T^{A}_{HP.i}}{M^{A}} \frac{k^{A}_{HP}}{k^{A}_{HP}-1} \left[a_{HP} P^{A}_{HP.o,p} + b_{HP} - 1 \right] \qquad 1 \leq p \leq P \tag{I}$$

And with some rearrangement,

$$E_{HP,p}^{A} = \frac{a_{HP}}{\eta_{HP}} \frac{z_{HP}^{A} R T_{HP.i}^{A}}{M^{A}} \frac{k_{HP}^{A}}{k_{HP}^{A}-1} \boldsymbol{F_{LP.S,p}^{A} P_{HP.o,p}^{A}} + \frac{\boldsymbol{F_{LP.S,p}^{A}}}{\eta_{HP}} \frac{z_{HP}^{A} R T_{HP.i}^{A}}{M^{A}} \frac{k_{HP}^{A}}{k_{HP}^{A}-1} \; [b_{HP} - 1] \qquad 1 \le p \le P \tag{II}$$

Step B: The McCormick envelopes

Now, we have a bivariable term $F_{LP.S,p}^{A} P_{HP.o,p}^{A}$. For tackling this, we introduce a new variable $FP_{HP,p}^{A} = F_{LP.S,p}^{A} P_{HP.o,p}^{A}$ which linearizes the appearance of the compressor function,

$$E_{HP,p}^{A} = \frac{a_{HP}}{\eta_{HP}} \frac{z_{HP}^{A} R T_{HP.i}^{A}}{M^{A}} \frac{k_{HP}^{A}}{k_{HP}^{A}-1} \; \boldsymbol{FP_{HP,p}^{A}} + \frac{\boldsymbol{F_{LP.S,p}^{A}}}{\eta_{HP}} \frac{z_{HP}^{A} R T_{HP.i}^{A}}{M^{A}} \frac{k_{HP}^{A}}{k_{HP}^{A}-1} \; [b_{HP} - 1] \quad 1 \le p \le P \tag{34-1}$$

Then we introduce the following four constraints as the McCormick envelopes [18],

$$FP_{HP,p}^{A} \ge F_{LP.S,p}^{A,L} P_{HP.o,p}^{A} + F_{LP.S,p}^{A} P_{HP.o,p}^{A,L} - F_{LP.S,p}^{A,L} P_{HP.o,p}^{A,L} \qquad 1 \le p \le P \tag{34-2}$$

$$FP_{HP,p}^{A} \ge F_{LP.S,p}^{A,U} P_{HP.o,p}^{A} + F_{LP.S,p}^{A} P_{HP.o,p}^{A,U} - F_{LP.S,p}^{A,U} P_{HP.o,p}^{A,U} \qquad 1 \le p \le P \tag{34-3}$$

$$FP_{HP,p}^{A} \le F_{LP.S,p}^{A,U} P_{HP.o,p}^{A} + F_{LP.S,p}^{A} P_{HP.o,p}^{A,L} - F_{LP.S,p}^{A,U} P_{HP.o,p}^{A,U} \qquad 1 \le p \le P \tag{34-4}$$

$$FP_{HP,p}^{A} \le F_{LP.S,p}^{A} P_{HP.o,p}^{A,U} + F_{LP.S,p}^{A,L} P_{HP.o,p}^{A} - F_{LP.S,p}^{A,L} P_{HP.o,p}^{A,U} \qquad 1 \le p \le P \tag{34-5}$$

where, *L* and *U* refer to lower and upper bounds of the variables,

$$F_{LP.S,p}^{A,L} \le F_{LP.S,p}^{A} \le F_{LP.S,p}^{A,U} \qquad 1 \le p \le P$$

$$P_{HP.o,p}^{A,L} \le P_{HP.o,p}^{A} \le P_{HP.o,p}^{A,U} \qquad 1 \le p \le P$$

Therefore Eq. 31-1 together with Eqs. 34-2 to 34-5 represent the linearized form of the nonlinear Eq. 31. Similar approach could be employed for other nonlinear equations (i.e. Eqs. 40, 48, and 49).

Appendix B: Execution summary of problems

Table A1: Execution summary of the optimization programs in Examples 1 to 3

Problems			Problem Size	System settings	NSW market				Victoria Market			
Scenario	**Example No**	**Time period**	**No. equations No. variables No. discrete var.**	**System specs and execution settings**	**Optimal value**	**Abs. gap (relative gap)**	**Execution time**	**Recourse usage**	**Optimal value**	**Abs. gap (relative gap)**	**Execution time**	**Recourse usage**
Without storage	**1**	**Jan-Jun**	118,261 87,601 26,280	Desktop PC 1.80 GHz Intel Core Processor 8 GB RAM Resource limit: 10e8 Relative gap: 0.05	9309665.6	0.0	20.64	3.48	12036659.7	205845.1 (0.0171)	20.61	2.14
	1	**Jul-Dec**			5797652.6	0.0	20.87	4.75	2658408.5	2658409.5 (0.0)	20.78	7.89
With storage	**2**	**Jan-Jun**	324,121 205,861 52,560	HPC 200 GB RAM 300 hr walltime Resource limit: 10e8 Relative gap: 0.05	14136533.7	412171.8 (0.0292)	14.44	1059.58	20930635.8	405821.4 (0.0194)	12.70	749.72
	2	**Jul-Dec**			11956676.7	295769.7 (0.0247)	12.80	718.19	8577215.4	269197.4 (0.0314)	12.70	592.63
	3-1	**Jan-Jun**			11751164.6	2494.8 (0.0002)	12.80	12.45	14998125.7	1270.5 (0.0001)	11.92	10.28
	3-1	**Jul-Dec**			8544563.7	1681.76 (0.0002)	12.74	12.73	4852829.3	762.8 (0.0002)	12.03	10.35
	3-2	**Jan-Jun**			13358309.9	595730.8 (0.0446)	11.93	1174.40	19909101.3	555153.7 (0.0279)	11.92	766.92
	3-2	**Jul-Dec**			10392992.5	386713.8 (0.0372)	12.07	828.23	7522231.6	367205.4 (0.0488)	11.83	756.66
	3-3	**Jan-Jun**			13133541.5	596465.2 (0.0454)	12.06	1145.05	20140426.0	526424.0 (0.0261)	11.96	738.44
	3-3	**Jul-Dec**			10090153.1	352133.4 (0.0349)	12.09	943.64	7675959.0	332971.0 (0.0434)	12.30	724.21
	3-4	**Jan-Jun**			11986360.7	595989.7 (0.0497)	12.44	1329.86	18467653.0	509526.4 (0.02760)	11.94	875.72
	3-4	**Jul-Dec**			9132537.1	296606.3 (0.0325)	11.96	1077.30	6275027.0	265180.2 (0.0423)	11.91	834.95

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