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Smart grid coordination of a chemical processing plant

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HIGHLIGHTS

- Propose a novel design to enable smart grid coordination of a chemical plant.
- Discover characteristics of two energy sources in smart grid coordination system.
- Operating cost savings influenced by the amount of variability in electricity price.
- Most favorable conditions required for operating costs to outweigh equipment costs.
- Energy storage does little to improve the economics of the case study.

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ABSTRACT

As the electric power grid evolves to a smart grid, the introduction of real-time price structures will provide consumers with the opportunity to obtain low cost (possibly negative cost) electrical energy. This work will propose a novel design for a utility plant within a chemical processing facility that will enable exploitation of the diurnal nature of expected electricity prices. Specifically, we will investigate an oil heating, gas fired furnace that has been augmented with an electric heater. A second configuration, that augments the electric heater with an energy storage unit, will also be investigated. Results indicate that substantial savings in energy cost can be achieved, but will likely be undercut by the capital costs associated with the electric heater.

1. Introduction

The operation of grid scale power systems is transitioning from a centralized single party approach to a deregulated (market based) approach that encourages active participation from multiple stakeholders (Farhangi, 2010; Ipakchi and Albuyeh, 2009; Chmielewski, 2014). Under such schemes the cost of electric energy is expected to track consumer demand. If electric energy consumption is low, then only low cost generators (coal and nuclear) need be online. Conversely, when consumer demand is high, higher cost generators (combined cycle gas turbines) will need to be brought online. At no point can there be an imbalance between consumption and generation (Grainger and Stevenson, 1994). If such an event were to occur, there would be a catastrophic failure on the grid, likely leading to a blackout. The net result is a price of electricity that tracks the diurnal cycle of consumer demand (see Fig. 1).

In parallel there has been substantial growth in renewable power sources (wind and solar). However, the intermittent nature of these sources is expected to increase the volatility of electricity prices, especially if dispatch capable fossil plants are decommissioned (Lindenberg et al., 2008). If renewable power is available and demand is low, then prices could drop below the operational costs of the base-load plants (coal and nuclear) – notice the negative price during the second day of Fig. 1. On the other hand, if renewable power is not available while consumer demand is high, prices may spike due to the required use of very high cost generators (simple cycle gas turbines, also known as peaker plants).

The notion of Demand Response (DR) envisions consumers participating in the operation of the grid (Rahimi and Ipakchi, 2010; Walawalkar et al., 2010). While there are many DR mechanisms (Chmielewski, 2014), the current effort will focus on economic response. Under such a program, consumers will be incentivized by the price of electricity to use more or less electric energy at particular times of the day. A number of efforts have advocated the use of DR in a residential setting (Chen et al., 2012; O'Neill et al., 2010; Zachar et al., 2015), as well as in commercial buildings (Halvgaard et al., 2012; Ma et al., 2012; Oldewurtel et al., 2010; Mendoza-Serrano and

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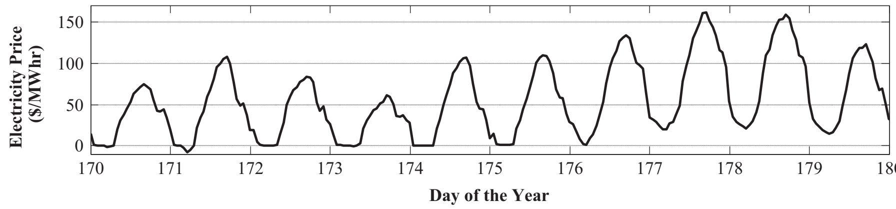

Fig. 1. Historic electricity prices (Chicago, 2008) (Pennsylvania, New Jersey, Maryland Interconnection, 2013).

Chmielewski 2014; Salsbury et al., 2013; Touretzky and Baldea, 2014). In the industrial sector, a number of DR opportunities have been explored, including; aluminum smelting (Todd et al., 2009), steel production (Castro et al., 2013), industrial gas production and distribution (Huang et al., 2011; Baumrucker and Beigler, 2010), and chemical processing (Mitra et al., 2012; Mendoza-Serrano and Chmielewski, 2013).

The current effort focuses on a chemical processing facility in the sense that the energy used to drive a portion of the process is delivered via a hot oil utility stream, serviced by a natural gas fired furnace. The proposition is to augment this furnace with an electric heater, as illustrated in Fig. 2. As we will see, optimal operation of this augmented system can be achieved using a policy that is a function of fuel and electricity prices, but is independent of time. This policy is akin to that resulting from a real-time optimization algorithm.

It should be highlighted that many chemical processing facilities purchase electric energy based on market prices through their energy management system. However, these energy management systems rarely use energy prices to influence the operation of a chemical plant. The current effort proposes one possibility of allowing energy prices to influence plant operation, but the scope is restricted to the utility plant and does not attempt to make any changes to the production side of the plant. While changes to production schedules, based on electric energy prices, may yield a theoretical economic benefit (Mendoza-Serrano and Chmielewski, 2013), the practical impact on equipment degradation and safety procedures is unknown and will result in a level of risk that most in the chemical industry are unwilling to accept.

In many cases, use of an energy storage device will enhance the performance of a smart grid coordinated system (Mendoza-Serrano and Chmielewski, 2013, 2014; Omell and Chmielewski, 2013; Yang et al., 2012). As such, we will also investigate the configuration of Fig. 3, which employs a molten salt energy storage unit along with a secondary heat exchange operation. In addition to an increase in the number of decision variables, at both the design and operational levels, the need to account for the time history of the storage device will require the use of Economic Model Predictive Control (EMPC). General descriptions of EMPC can be found in Rawlings et al. (2012), Ellis et al. (2014) and Trana et al. (2014), while application of EMPC to smart grid coordination problems can be found in Halvgaard et al. (2012), Ma et al. (2012), Oldewurtel et al. (2010), Mendoza-Serrano and Chmielewski (2013, 2014), Huang et al. (2011), Omell and Chmielewski (2013), Adeodu and Chmielewski (2013), Salsbury et al. (2013), and Touretzky and Baldea (2014).

The choice to use thermal energy as the storage medium, as opposed to electrochemical batteries or gas compression, warrants some discussion. In the proposed configuration the end use of the stored energy is to heat a fluid. Thus, the most natural storage medium is thermal, since only one energy conversion step is needed – electric to thermal. If one were to use some other storage medium, then several conversion steps would be needed – for example a battery requires electric to chemical, chemical to electrical and finally electric to thermal. Since each of these conversion steps will have losses, the option with fewer steps is expected to be most efficient. A similar approach was used in Yang

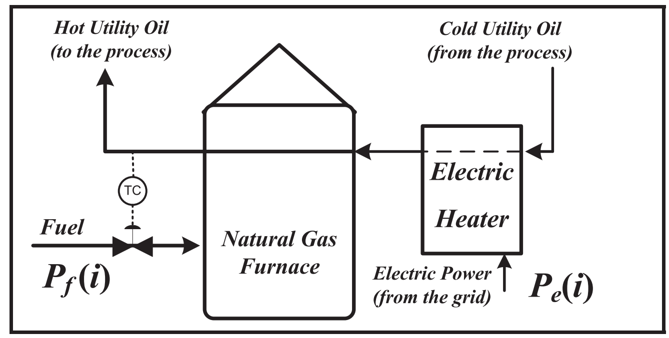

Fig. 2. Simplified process diagram of a utility plant with electric heating.

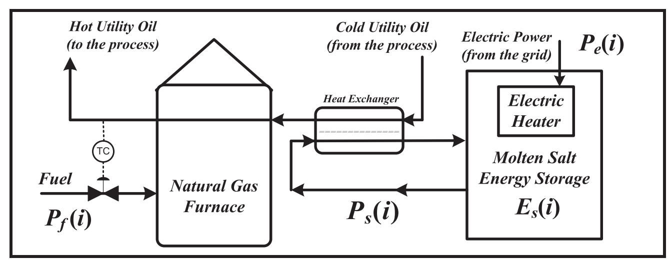

Fig. 3. Simplified process diagram of a utility plant with electric heating and energy storage.

et al. (2012), where compressed air was selected as the storage medium because the end use was to augment the compressed air stream into an air separation unit.

2. Analysis of the electric heater only case

The envisioned furnace will heat an oil utility stream using natural gas as the energy source. We assume that the required rate of heat to the oil is constant for all time and equal to P_{load}. If the conversion efficiency of the furnace is η_f, then the required amount of fuel is P_{load}/η_f. Since the heat load is fixed, it is reasonable to define this as the maximum fuel rate to the furnace: $P_f^{max} = P_{load}/\eta_f$. The operating cost for this baseline case is calculated as $\sum_{i=1}^{M} c_f(i) P_f^{max}$, where $c_f(i)$ is the cost of fuel (in \$/MMBTU or equivalently in \$/MWh) during time interval i, and M is the number of time intervals of the analysis.

As indicated in Fig. 2, the electric heater augmented system will have the following energy balance:

$$\eta_f P_f(i) + \eta_e P_e(i) = P_{load} \quad (1)$$

where $P_e(i)$ is the electric power sent to the heater during time interval i, and η_e is the conversion efficiency of the heater. Notice that the heater has been placed upstream of the furnace, so that the existing oil temperature regulation equipment can continue to be employed. However, doing so carries the implicit assumption that the furnace will remain online at all times. Thus, we assume a maximum furnace turndown factor of δ, indicating that $P_f^{min} = (1-\delta)P_f^{max}$. This limit could