Cyber-Physical Systems for Next Generation Intelligent Buildings

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ABSTRACT

The proliferation of the smart grid creates new opportunities for large buildings to act as smart end-points that provide mutually beneficial services for building occupants and the grid. In this article we describe how Cyber-Physical systems that provide rapid access to information and decision-making can enable buildings to autonomously interact with the grid. By participating in new real-time electricity markets on the *utility side of the meter* and day-ahead markets, buildings have the potential of achieving local efficiency and reliability gains while also facilitating the effective utilization of renewables.

1. INTRODUCTION

To reduce their consumption and energy costs, and to accommodate the use of distributed renewable generation, next generation intelligent buildings (NGIBs) are anticipated to act as smart components on the electric grid. In addition to eco-friendly design, they are expected to modulate their consumption to accommodate the integration of greener distributed generation that is by nature very intermittent. Our research aims at understanding how to design and build Cyber Physical Systems that will allow buildings to participate in emerging energy markets by exploiting detailed and close to real-time information about the state of the buildings and the state of the grid. We anticipate that such participation will be mutually beneficial allowing buildings to reduce their net energy costs while, at the same time, helping to manage peak loads, identify and reduce waste, and facilitate the integration of distributed renewable generation.

Advanced markets on the utility side of the meter are presently limited to wholesale markets operating over a balancing area's transmission system [3]. Retail/distribution markets are only emerging [4,5] with the presence of competing retailers who are given access to the distribution network but are not exposed to cost reflective of varying rates and charges (in time and space). We anticipate that with the advent of the smart grid [6, 7, 10, 11], **advanced retail markets** will soon be established and in this article discuss the requirements for such a future. Power markets are associated with various time scales spanning from months to days to minutes. We will consider *day ahead, adjustment* and *real-time* markets [2, 9, 12, 13, 14, 16]. Participation to these markets puts strict information requirements on buildings, expecting close to real-time information about usage patterns and load characteristics.

In this paper we provide a background introduction on utility markets and building requirements. We then use it to explore an illustrative example of how intelligent buildings with Cyber-Physical capabilities can participate in such markets.

2. UTILITY MARKETS BACKGROUND

The *day-a-head* market closes at noon of day *d*-1 and determines energy supply and demand as well as supply of capacity reserves for each of the 24 hours of day *d*. Each market participant offers price/quantity pairs for energy and reserves, (u^E, Q^E) and (u^R, Q^R), respectively. The market administrator called **Independent or Regional System Operator (ISO/RTO)** clears the market by maximizing consumers' plus producers' surplus subject to energy balance, transmission, reserve capacity requirements and several other constraints that we do not discuss here for simplicity of exposition [2, 12, 13, 14, 16]. The ISO schedules enough generation and reserves to meet demand and reserve requirements and obtains clearing prices that we denote for a given hour h at the bus that supplies the building's region by $\Pi^E(h)$ and $\Pi^R(h)$, for energy and reserves respectively. Clearing prices are used to charge consumers and pay generators. Capacity reserves are equivalent to a promise to stand by and provide, as required and within an agreed upon delay, capacity up to the maximum quantity sold. Current practice has established **primary or frequency control, secondary or regulation service, and tertiary reserves** corresponding to the provider's obligation to make available upon request with a maximum of 30 seconds, 5 minutes and 15 minutes delay, respectively. Primary and secondary reserves, commonly referred to in the United States as automatic frequency control, and regulation service reserves respectively, must offer a band of up or down capacity.

Adjustment markets are similar to day-ahead markets except they have a horizon of fewer than 24 hours and close after the day-ahead market: Adjustment markets are in fact secondary markets that renegotiate energy purchases and reserve sales after additional information becomes available.

Real-time (or close to real-time) markets also clear energy and capacity reserves on a nodal/bus basis but cover a single period of five to fifteen minutes.

Note that day ahead, adjustment and real-time markets are coupled and clear sequentially. Quantities secured in the day-ahead market can be renegotiated, i.e., increased or decremented in subsequent adjustment and real-time markets. Day-ahead markets can be thought of as satisfying a scheduling and risk hedging objective while real-time markets provide the opportunity for a final adjustment of energy and reserve requirements as these are identified after the revelation of uncertainties.

Whereas wholesale markets emerged in the mid 1990s [3], retail markets are only starting to develop. We consider them here for two reasons: (i) the advent of the smart grid will make the information needed for real-time retail markets operation readily available [6, 7, 10, 11], and (ii) the distribution network share of the overall cost of electricity is on the order of 30-35%. Although a significant portion of distribution revenue requirements – possibly more than half – cannot be recovered from marginal cost pricing, 30-35% of overall costs is significant enough to justify focusing on retail market-based competition as a means for increasing productivity. Retail/Distribution costs vary over time and consist of three main components: (i) marginal line losses that vary over the day from 2x3% of average losses to 2x10% of average losses, hence 6% to 20%, (ii) local line/feeder/transformer congestion, and (iii) reactive power/quality of service/voltage support – note that since the provision of reactive power is more of a local issue, it is expected that it will be handled to a great extent by the retail markets.

3. FREQUENCY AND REGULATION SERVICE RESERVES

Securing generation capacity reserves in advance and managing them in real-time is synonymous to power system contingency planning and stability/security control. In competitive markets, the system operator procures reserves in the market and manages them with direct commands issued from its control center. As markets mature, reserves are procured and cleared simultaneously with energy [13, 16]. However, market participants offering frequency control and regulation service reserves are still limited to centralized generators, while interruptible loads are present but play a secondary role and are rewarded outside of the day a-head and real-time markets through long term contracts, namely, energy rate discounts. In July 2006, PJM, the largest US wholesale power market, modified its rules to allow loads to be certified for full participation in dynamic reserve markets [15, 17]. This resulted in lower 15-minute operating reserve costs with loads performing more reliably than generators [15], and Energy Service Companies such as EnerNOC [www.enernoc.com] emerging as successful load aggregation and management businesses. Nevertheless, for reasons we attribute to the lack of the requisite information and automated decision making capabilities, faster reserves such as frequency control (30 sec) and regulation service (5 min) have not yet been offered by loads in any significant quantities. It is noteworthy that the absence of loads from the supply of fast reserves comes at a time when the integration of intermittent generation [1, 8, 18, 19, 20, 21, 23, 25] is imposing a steep increase in the requirement of such reserves. Specifically, reserve requirements are of the order of 5-10% of wind farm nameplate capacity [22, 24]. Whereas currently wind generation accounts for less than 2% of electric energy generation, it is increasing rapidly with a 39% increase observed during 2009.

To understand regulation service (5 min) market rules, consider the sale of 100kW of regulation service reserves for a period of one hour. The seller, in exchange for a reward equal to the hourly regulation service market clearing price times 100kW, undertakes the obligation to respond to requests that may be issued as often as every 5 seconds requiring increase or decrease of consumption at a rate of 100/5=20kW per minute to a maximum of 100kW over a period of 5 minutes. As an example: the control center may request a decrease of load by 50 kW in 2.5 minutes, or, an increase of load by 70kW in 3.5 minutes. If a NGIB offers 100kW of regulation service and the offer is accepted, welfare maximization guarantees that $|\Pi^E(h) - u^E(h)| + u^R(h) < \Pi^R(h)$ where $u^E(h)$ and $u^R(h)$ are the energy and reserves bid and offer for hour h, while $\Pi^E(h)$ and $\Pi^R(h)$ are the energy and reserve market clearing prices. Note that $|\Pi^E(h) - u^E(h)|$ is the per kWh opportunity cost of consuming $Q^R(h)$ in order to be able to provide regulation service reserves of $Q^R(h)$ MW up or down, as opposed to 0 or $2Q^R(h)$ that a market participant would prefer to consume when $u^E(h) \neq \Pi^E(h)$.

The NGIB benefit from successfully selling $Q^R(h) = 100$ MW of regulation service reserves is a lower effective price of energy, namely it is associated with a charge of $[\Pi^E(h) - \Pi^R(h)]\, Q^R(h)$ as opposed to $\Pi^E(h)Q^R(h)$. At the same time, society will benefit from a lower cost of securing reserves that will result from the higher supply of reserves. As mentioned repeatedly, the latter is a key requirement for widespread integration of wind and other intermittent clean generation into the grid.

4. AN ILLUSTRATIVE EXAMPLE

To participate in the aforementioned markets NGIBs need to rapidly collect and process information from the Cyber and Physical worlds. To this end we develop two distinct layers, a Cyber-Physical Event Processor (CyPEP) and an Energy Management Decision System (EMDS). The CyPEP provides an execution environment that collects information from heterogeneous sources, derives the state of the building and actuates at the recommendations of the EMDS. The EMDS is responsible for considering the market conditions and the state of the building to make optimal decisions on how the building should interact with the markets and the physical world.

In a typical day the CyPEP obtains information and provides to the EMDS layer (*i*) forecasts of building energy usage and degrees of freedom authorized by occupants (this is done a few times per day to assist with EDMS layer's bids and offers to the day ahead and adjustment markets); (*ii*) real-time information on utility side-of-the-meter constraints including line and transformer capacity utilization, voltage support/power factor needs, marginal line losses and real-time clearing price forecasts; and (*iii*) the real-time energy usage (real and reactive) of the building containing consumption by use type and degrees of freedom regarding increase/decrease/ modulation of usage specific capacity – not energy consumption. The latter can be done through packetization/standard-unit-quantification of energy required over a short period of time, so that in general energy and capacity are distinguished only by the time duration over which a certain number of electric energy packets are required. This information is needed to allow the EMDS layer to determine optimal bids and offers to both wholesale and retail real-time markets. Figures 1 and 2 provide illustrative examples of typical quantities procured in the day ahead market and their augmentation through real-time market transactions. The data presented in these figures correspond to actual measurements recorded on meters at 189 buildings on the Yale University Campus. Real time marketransactions correspond to a sizable portion, ~20%, of the overall consumption. Initial analysis of flexible demand on the Yale campus indicates that, in all likelihood, it can provide fast,

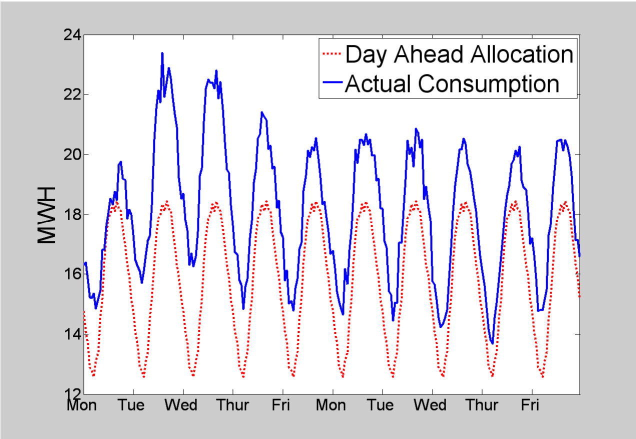

Figure 1 Illustrative example of day-ahead quantities

regulation service reserves on the order of 20% of peak load. The significance of this offering is twofold: it can reduce Yale campus electricity costs by 10-15%, but it also promises to be synergistic to a robust growth of intermittent wind and solar generation.

The EMDS layer provides the necessary *decision support* for the NGIB's participation to the wholesale and distribution/retail day-ahead, adjustment and real-time markets. To this end it must determine optimal bids for hourly energy purchases and regulation service reserve sales, and optimal occupant rewards to act as incentives for them to authorize modulation of their energy usage. These decisions are selected to optimize the expected net cost of energy in each hour (or a shorter time period) subject to securing quantities that meet occupant preferences, while assuring that reserve sale obligations can be met. It should be noted that day-ahead decisions are made under the anticipation that adjustments will be possible at a later time when adjustment markets close, and finally when the real-time market closes.

For effective EMDS, the CyPEP must acquire, develop and provide information on (*i*) the joint probability distribution, $u(\Pi^E(h), \Pi^R(h)|\theta(h))$, of energy and regulation service reserves clearing prices, $\Pi^E(h)$ and $\Pi^R(h)$ for each hour $h=1,2,\ldots,24$, conditional upon relevant power system forecasts $\theta(h)$ such as conventional generation outages and system wide intermittent generation output, (*ii*) hourly forecasts of local distribution line/transformer capacity constraints $C(h)$, and marginal line losses, $ML(h)$, (*iii*) the forecasted building energy requirements by use type, e.g., HVAC needs given the weather forecast, electric vehicle charging needs and desired departure times, office occupancy and lab operation patterns, *(iv)* the building generation forecast – roof top PV, wind turbines, etc., and finally, (*v*) expected occupant authorizations to modulate consumption (e.g., light, hood ventilation, laboratory utility, HVAC, electric vehicle battery charging, thermostat operated resistive loads, and the like). The joint probability distribution information on clearing prices may appear onerous but it is not. Indeed, well developed wind and intermittent generation forecasts [18], as well as clearing price forecasts, are available with standard error on the order of of 10% on a day ahead basis and 2-3% on an hour ahead basis.

The EMDS layer participates in the day-ahead markets in a hedging and planning mode. It optimizes NGIB storage charging and discharging and determines HVAC consumption profiles that leverage local energy storage. It also implements pre-cooling/pre-heating strategies taking advantage of temporal price differences that exceed losses. Such losses can be computed given outside temperature profiles, the building's thermal mass and losses, and the storage device losses. Finally, the EMDS layer participates in subsequent adjustment and real-time markets.

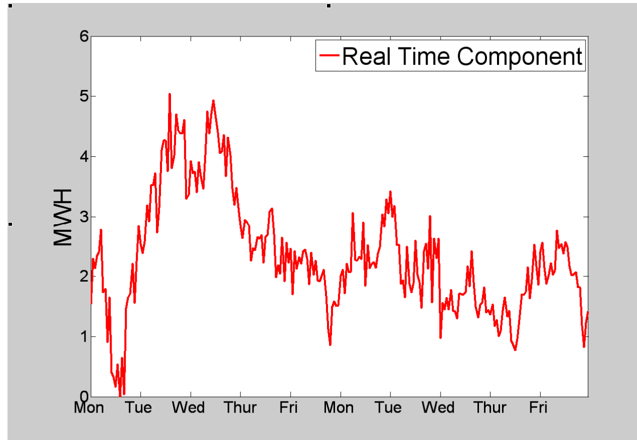

Figure 2 Adjustment and Real-Time markets component

Although the detailed description of the EMDS optimization tools are beyond the scope of this article, we consider it worthwhile to emphasize the following two important aspects of EMDS: *first* that expected net costs associated with purchasing hourly energy $Q^E(h)$ and selling regulation service reserves $Q^R(h)$ in the presence of marginal line losses, $ML(h)$, equal $E[\, \Sigma_h [\Pi^E(h)\, Q^E(h) + (\Pi^E(h) - \Pi^R(h))\, Q^R(h)](1+ML(h))]$, where E[.] denotes expectation, and *second* that regulation service reserve obligations $Q^R(h)$ must satisfy:

(1) Occupant incentives that are sufficient for them to authorize modulation of $Q^R(h)$ from 0 to $2Q^R(h)$, and

(2) The local line/transformer constraint $Q^E(h) + 2\, Q^R(h) < C(h)$.

To understand how the constraint under (2) above can be met, consider the following examples:

- $v_i(h)$ electric vehicles, $i=1,2,\ldots,m$ are plugged in at hour h. Each has: battery charging capacity of c kW, declared departure time $h+T_i$, and uncharged battery capacity $e_i(h)$ kWh. EMDS incentives for modulation authorization include the following: If at time T_i $v_i(h)$ is not fully charged, it will receive compensation \$$\pi$ per kWh uncharged.

- Building offices are equipped with three light settings corresponding to electricity consumption rates 0 (off), r and $2r$. Of those offices, $n(h)$ are unoccupied while of those occupied, the occupants in $q(h)$ of them have responded positively to an EMDS incentive of \$$p(h)$/hour and authorized modulation of their lights between scale 1 and 2. We assume that $q(h)$ is an increasing function of $p(h)$.

With some thought it can be deduced that if incentives \$$\pi$/kWh and \$$p(h)$/hour are estimated and provided so as to result in the above mentioned modulation authorizations, the maximal offer of regulation service reserves that is feasible equals $Q^R(h) = mc/2 + n(h)r + q(h)r/2$.

Note that NGIB participation in the *adjustment and real-time* markets managed by the EMDS layer is the solution of a constrained optimization similar to that solved for day-ahead market participation. The only difference is that shorter horizon market participation decisions are made conditional upon two sets of additional information: *first*, updated lower variance forecast and probability distribution information, and *second*, the known sales, purchases and clearing prices realized in the day ahead and earlier adjustment markets. The latter demonstrates clearly the coupling of the sequential day-ahead, adjustment and real-time markets.

5. CONCLUSIONS

Implementation of demand management of the type described above requires a carefully designed Cyber-Physical System that ensures optimal actions prescribed in the cyber world do not result in any safety or comfort violations in the physical world of the building. This entails precise knowledge of the state of the building in terms of electric load decomposition, occupancy patterns and occupant preferences. Optimal decisions require good knowledge of the cyber world in terms of weather predictions and up-to-date market information.

To understand the nature of electric loads, and to determine which loads are interruptible and which are not, our research has been developing lightweight methodologies for determining electric load decomposition without requiring exhaustive sub-metering of the building. This is done by observing the binary ON/OFF state of individual electricity uses and the consumption variations at the central meter so as to estimate usage breakdowns over small time intervals [26]. Future requirements are projected using spatiotemporal usage patterns extracted from a lightweight sensing network inside the building. Our current research is developing a Cyber-Physical Event Processor (CyPEP) that will provide the fabric for handling incoming and outgoing information streams. The CyPEP will also host the algorithms for estimating the state of the building and will provide an interface for the EMDS layer to receive state information and provide actuation commands. To enforce physical system safety, the CyPEP will provide a Physical Access Control Layer that will monitor safety conditions and user preferences in real-time. This will raise exceptions and act as a dampening mechanism when aggressive EMDS requests cannot be accommodated by the physical system.

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