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Are US utility standby rates inhibiting diffusion of customer-owned generating systems?

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Abstract

New, small-scale electric generation technologies permit utility customers to generate some of their own electric power and to utilize waste heat for space heating and other applications at the building site. This combined heat and power (CHP) characteristic can provide significant energy-cost savings. However, most current US utility regulations leave CHP standby rate specification largely to utility discretion resulting in claims by CHP advocates that excessive standby rates are significantly reducing CHP-related savings and inhibiting CHP diffusion. The impacts of standby rates on the adoption of CHP are difficult to determine; however, because of the characteristically slow nature of new technology diffusion. This study develops an agent-based microsimulation model of CHP technology choice using cellular automata to represent new technology information dispersion and knowledge acquisition. Applying the model as an *n*-factorial experiment quantifies the impacts of standby rates on CHP technologies under alternative diffusion paths. Analysis of a sample utility indicates that, regardless of the likely diffusion process, reducing standby rates to reflect the cost of serving a large number of small, spatially clustered CHP systems significantly increases the adoption of these technologies.

Keywords: Distributed generation; Agent-based model; New technology

1. Introduction

While large combined heat and power (CHP) systems have been used for decades in industrial, hospital and university applications, recent technology innovations permit smaller utility customers to self-generate all or a portion of their own electricity onsite and to apply waste heat from the generation process for thermal uses such as space heating, water heating, and air conditioning. For customers with appropriate hourly electric and thermal loads, overall CHP system efficiency can reach 85 percent compared to a maximum of about 50 percent for the most efficient central utility generation plants and about 33 percent for the average US utility generation plant.[1] CHP systems improve the efficiency of the entire electric generation system, reduce emissions and can provide substantial reductions in utility customer energy costs.

Currently, the primary US market for new small-scale CHP technologies is the commercial sector. A 2000 US Department of Energy study found 74 Gigawatts (GW) of technically feasible potential[2] for commercial sector CHP system installations representing about 12 percent of total electric utility-owned capacity in the year 2000.

Recent standardization of utility interconnection requirements, remote monitoring/control and guaranteed service contracts are a few recent CHP market innovations that facilitate CHP installations. Emission control technologies guarantee compliance with the most stringent local requirements while CHP systems can provide improved power quality and reliability compared to grid-delivered power.

In spite of these developments, existing small US commercial sector systems probably number no more than

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[1]Overall system efficiency is the percent of generation energy input delivered as useful energy to the final user. See DOE, 2000, 2002 and 2003 for a description of CHP technologies, markets and case studies.

[2]Technically feasible potential includes installations where a majority of waste heat can be utilized with limited changes in existing building thermal energy systems (e.g., space heating).

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several thousand (Jackson, 2005; DOE, 2000) and while that number is increasing (Prabhu, 2002; NECHPI, 2005), CHP systems appear to be making only modest inroads in the market (NECHPI, 2005).

CHP proponents frequently identify high standby (or backup) rates, charged by the local utility when CHP systems are unexpectedly unavailable, as one of the primary reasons for the slow adoption of CHP systems (Jimison et al., 2004; Casten, 2003). A recent addition to the literature (Firestone and Marnay, 2005) confirms the important impact of standby rates in six New York utility service areas.

While utilities are required to determine standby electric rates based on cost, this process is complicated and sometimes inconsistent with no agreed-upon methodology. For example, state regulatory agencies require revenue neutrality[3] in designing standby rates; however, crediting CHP customers for fixed cost savings associated with generation and distribution would automatically increase the allocation of additional fixed costs to non-standby customers. On the other hand, the Federal Energy Regulatory Commission (FERC), directs utilities to incorporate utility savings associated with intermittent demands in standby rate design. Consequently, utilities typically have considerable discretion in setting standby rates for incremental service required if the utility customer's CHP-generating system is not operating.[4] This rate-setting flexibility puts utilities in the position of regulating competition from their own customers.[5] Furthermore, revenue reductions resulting from cost-based standby rates have an exaggerated impact on profits for investor-owned utilities (Weston, 2000; Moskovitz, 2000, Regulatory Assistance Project, 2000) and create rate pressure for publicly owned utilities.[6]

[3]Once rates are set, revenue neutrality requires any change in the rate for a single rate class to have no impact on revenue requirements of other rate classes.

[4]Standby rates differ by utility primarily in "demand" charges (charges for the maximum 15-min kW use in the month). Most utilities apply "ratchet" clauses that bill demand based on the maximum kW in the previous year. Standard non-CHP demand charges typically range from \$6 to \$9 per kW. Utilities who strive for revenue neutrality set standby rate demand charges as close to standard demand charges as possible so that even one unplanned 15-min system downtime in the year will recover lost revenue. One utility, in recent years, set standby rates at more than double the standard rate, which could have conceivably increased revenue from CHP customers (LIPA, 2001). More recent standby rate setting practices appear to set standby demand rates at approximately 50 percent of full demand charges using a combination of capacity and use charges (e.g, LIPA, 2004).

[5]Each utility is regulated by one or more agencies in its own state. Consequently, this description includes some generalization. The local distribution utility designs and applies standby rates and remains regulated in all US states.

[6]Adoption of CHP technologies also reduces the utility's generation, transmission and distribution assets relative to a world without CHP. In addition to the Averech-Johnson effect, which explains over-investment in capital by regulated firms, a larger asset base reduces the relative impacts of random negative influences on revenue such as weather and economic fluctuations.

An equally compelling argument, however, can be made that the slow adoption of CHP is characteristic of new technology diffusion and a long-recognized reluctance of firms to invest in energy-saving investments (Jaffe and Stavins, 1994; Jaffe et al., 2001; DeCanio, 1998).[7]

The extent to which CHP diffusion is limited by current regulatory practices as opposed to reflecting traditional new technology diffusion has important policy implications for the \$239 billion US electric industry. CHP systems can potentially offer a significant opportunity to improve energy efficiency and reduce emissions. Encouraging this resource through policy initiatives; however, requires understanding the nature of current impediments, if any, to the adoption of CHP technologies.

Unfortunately, lack of utility CHP data, nonstandard interconnection fees, revisions in standby rates over time, complicated nonlinear electric rate structures that differ by utility and many other data difficulties prevent statistical tests of these hypotheses.

The objective of this study is to develop an agent-based microsimulation model of new CHP technology diffusion that permits analysis of utility standby-rate setting practices on the adoption of these new technologies. The remainder of this paper is organized as follows: The next section provides a brief review of relevant literature. Section 3 describes the conceptual model and Section 4 presents an empirical model specification. Section 5 describes analysis results. The final section provides a summary.

2. Relevant literature

Empirically assessing the impacts of standby rates on the diffusion of new CHP technologies requires a model structure that can represent (1) detailed CHP technology characteristics, (2) individual agent hourly electric and thermal energy use heterogeneity, (3) agent decision criteria heterogeneity, (4) detailed non-linear utility rate structures and (5) the endogenous spread of information among agents and agent knowledge accumulation.

The agent-based model developed in this study extends traditional economic microsimulation-modeling to accomplish these tasks by including bounded rational agent investment behavior and an agent-based process to represent agent interactions and the dissemination of new technology information. Relevant literature antecedents and modeling considerations are described in the remainder of this section.

2.1. Microsimulation models

Microsimulation approaches have been applied to accommodate the first four modeling issues above in

[7]Lee (2003) and others argue that customer-sited generation yields limited value relative to attributes of grid-provided power and is likely to serve only niche applications. As indicated in a later section, the analytical approach developed in this study accommodates CHP attribute values as positive and negative costs relative to grid power.

energy sector applications since the early 1980s. (Goett and Mcfadden, 1982; Jackson, 1986, and Jackson, 1994). US state energy agencies and utilities have used these models to analyze and forecast the impacts of detailed conservation technologies and energy policies in both residential and commercial sectors. Microsimulation models represent the individual behavior of a sample of agents with the ability to expand the results to determine impacts of population segments as well as the entire population. The ability to forecast and evaluate policies for any subset of the sample of agents provides policymakers with a consistent, comprehensive framework for ex ante evaluation of social and economic policies.[8]

CHP Microsimulation modeling applications have been less robust. Most studies have addressed only technical potential (DOE, 2000) or have used arbitrary investment criteria (e.g., a 10-year payback requirement, DOE, 2002), historical trends (CEC, 1999) and heuristic aggregate representations (NYSERDA, 2002) to evaluate the CHP market. While these CHP potential estimates provide insight on long-run upper-bound estimates of potential CHP penetration and energy savings, they are not useful in assessing utility standby rate impacts.

2.2. Modeling agent CHP investment behavior

CHP technologies provide an opportunity to reduce energy services cost by generating a portion of the building's electricity use and applying waste heat to supplement space heating and other thermal building requirements previously fueled with natural gas or oil. CHP systems are typically integrated in existing space heating, water heating, air conditioning, and other energy systems and do not require early replacement of existing energy-using capital.

Virtually all empirical analyses of actual energy-related investments have found significantly larger implied discount rates than can be explained by extending traditional investment theory to include uncertainty with respect to future fuel prices and equipment performance, unrepresented transaction costs, the option value of delaying the investments and other factors. The difference between observed implicit discount rates and financing costs has given rise to the so-called "energy paradox" (Shama, 1983) which remains a critical unresolved issue in energy and environmental analysis (Jaffe and Stavins, 1994; DeCanio, 1998).

The energy paradox is especially difficult to explain as part of cost-minimizing behavior of firms,[9] particularly larger firms that presumably apply more sophisticated investment criteria when considering energy-saving investments. A recent analysis of energy-savings investments in industrial firms (Anderson and Newell, 2002) found that even after detailed onsite engineering studies and cost-benefit analysis, which presumably minimized information cost and reduced uncertainty with respect to expected savings, firms still exhibit an average implicit discount rate of 75 percent.

A good deal of evidence indicates that firms do, in fact, use criteria for energy saving and similar capital investments other than net present value or equivalent investment analysis. A variety of previous studies have reported payback analysis as the predominant decision criterion used by firms in considering energy-related investments (Anderson and Newell, 2002; Lefley et al., 2003; Koomey, 1990, Kulakowski, 1999; Muller et al., 1995; DOE, 1996). Related empirical evidence is provided in a study by Lefley et al. (2003) that found 84 percent of financial decision makers in large companies use payback analysis alone or in combination with other investment criteria when considering advanced manufacturing technologies (i.e., computer-controlled processes).

The fact that this group of decision makers, who are undoubtedly aware of more sophisticated investment analysis techniques, chose to use payback analysis is consistent with a bounded rationality (Simon, 1955) view of decision makers applying simpler decision rules when faced with complicated investment decisions. Nelson and Winter (1982) extended this view to include procedural rationality based on firm-level learning over time and the use of procedural rules to provide decision-making continuity.

Minimizing model estimation and forecast error is especially important in policy modeling applications; consequently, agent CHP purchase decisions in this study are based on individual payback criterion. That is, CHP investment occurs when:

$$\text{Initial Cost}/\text{Annual Savings} \quad < \text{PBR}, \tag{1}$$

where Initial Cost is equipment and installation cost of a CHP system, Annual Savings is the annual savings in energy bills minus operating, maintenance and CHP fuel costs, and PBR = payback criterion applied by the decision-maker (years).

The standard practice of applying a fixed corporate-specific payback requirement to individual energy-savings investments (Kulakowski, 1999) implies that a knowledge threshold is achieved prior to the final application of the payback analysis. Otherwise, decision-makers would use different payback requirements to accommodate varying levels of uncertainty or information available concerning the individual investments. The cellular automata process described in the next section is used to represent CHP information dissemination and agent knowledge acquisition.

Since nearly all CHP utility customers have grid power, even during unexpected CHP downtimes, the value of CHP

[8] Microsimulation models were originally suggested by Orcutt (1957). See O'Donoghue (2001) for a survey of dynamic microsimulation modeling applications.

[9] Most energy-saving investment studies focus on residential investments in energy saving equipment. Ten studies of residential investments documented in Train (1985) have an average implicit rate of 66 percent.

attributes relative to grid attributes are incorporated as components of costs in the payback Eq. (1). Many of these cost components (e.g., maintenance costs) have been quantified in previous studies (e.g., DOE, 2002).

2.3. Information diffusion and knowledge acquisition with agent-based cellular automata

Microsimulation models can be extended to accommodate the fifth requirement mentioned above (endogenous spread of information among agents and agent knowledge accumulation) by incorporating endogenously determined agent-to-agent interactions and an agent knowledge accumulation process. Agent-based models are increasingly being used to explore micro foundations of many areas in economics and other disciplines (Tesfatsion, 2003; Dawid, 2006).

The dispersion of new technology information is recognized as a critical component in all models of new technology diffusion. Most theoretical and empirical models evaluate new technology penetration from an aggregate perspective. For instance Griliches' (1957) classic model represents the spread of information as if it were a disease spreading through the population. The seminal Bass (1969) model reflects a sigmoid curve with, among other parameters, a coefficient of imitation reflecting interpersonal communication or social contagion.

Agent-based models permit a more detailed and a potentially richer representation of the dynamics of information dispersion. The endogenous spread of new technology information from agent to agent is also consistent with a contagion process that, at an agent level, can be represented with as cellular automata (CA) process. Developed in the late 1940s by Stanislaw Ulam and John von Neuman as a model of self-reproducing systems, CA has been studied and used extensively in disciplines ranging from computer science to transportation planning. A cellular automation consists of discretely identified spatially arranged cells, each of which is characterized by a state of nature. The system evolves dynamically over time according to rules that define state changes for the individual cells based on exogenous influences and changes of state in other cells within a neighborhood. CA structures provide an intuitive mechanism to represent the spread of information from agent to agent and agent knowledge accumulation. Current CA applications in agent-based technology diffusion models tend to apply relatively aggregate and abstract characterizations of information-related cell states (Berger, 2001) or focus on theoretical and methodological issues of the CA process itself (Strang and Macy, 2001, Goldenberg et al., 2001). The model in this study extends these previous applications by applying a CA process to a microsimulation sample of individual agents to model the dissemination of new CHP technology information from one agent to another and to model agent knowledge acquisition which eventually results in the initiation of a purchase decision.

3. The conceptual model and a test of the standby-rate hypothesis

3.1. Model process

The model developed in this study simulates CHP investment decisions of each agent in a sample of commercial, institutional and government establishments. Hourly electricity, space heating, air conditioning and water heating energy uses, a payback requirement and availability of in-house energy expertise uniquely characterize each of these microeconomic agents.

Each agent's potential CHP system reflects an optimized CHP design that sizes generator capacity (kW) and waste heat applications based on the individual agent's hourly electric, thermal space heating, water heating and air conditioning demands.[10] The resulting system is characterized by an initial cost, annual maintenance cost, natural gas cost and other operating costs. Annual CHP benefits included avoided electricity costs and avoided natural gas costs (now provided by waste heat).

Agents consider CHP investment only when they acquire a threshold level of CHP knowledge. Each agent in the model originally begins with a state of ignorance concerning the new CHP technologies. A cellular automata (CA) process is used to model information dissemination and knowledge accumulation.

Each agent's accumulation of knowledge is a function of the level of its onsite energy-engineering expertise and exposure to sales/CHP installation information. The CA process moves each agent through individual states of a knowledge acquisition process towards a knowledge threshold. Once the threshold is reached, the agent considers CHP as an energy savings investment comparable to other energy-saving investments.

Sales contacts are targeted to agents in individual business segments that provide the greatest CHP potential savings based on segment averages. Agents are identified as belonging to neighborhoods consisting of agents of similar size in the same business segment (see Table 1). Business type segmentation is specified with respect to information flows that occur within similar industries. This specification is consistent with industry associations organized by business type (e.g., American Hospital Association, American Restaurant Association). The number of agents comprising a neighborhood within a business category is parameterized as part of the study analysis.

Larger agents, measured by number of employees, are contacted first. This representation reflects actual target marketing currently conducted by CHP suppliers. Sales

[10]Optimization of engineering system design may seem incompatible with a payback criterion that is "non-optimal" in a traditional investment sense. The first represents good engineering and design practice while the second represents, at least from the perspective of the firm making the investment, good investment strategy for uncertain energy-saving investments.

Table 1
Sample agent characteristics

	Population	Sample	Square feet	Peak kW	Employees	Annual kWh	Weekly operating hours	% Onsite energy manager
Office	2174	285	59,190	280	208	1,074,213	71	17.8
Retail	2306	73	17,046	61	14	232,756	79	11.5
Shopping mall	443	77	88,081	263	94	1,054,580	85	4.6
Grocery	1589	87	12,631	135	31	684,768	121	0.5
Warehouse	53	29	60,418	217	35	839,038	81	5.7
Refrig. warehouse	875	111	88,011	179	68	816,752	73	2.7
Assembly	526	70	39,329	162	40	507,819	85	2.9
School	943	107	54,774	146	102	348,455	55	3.6
Restaurant	2180	88	6592	79	31	301,230	97	0.7
Health	321	156	98,028	468	355	2,120,003	168	26.2
Hotel	246	63	37,669	180	22	674,236	166	13.2
Religious	113	17	29,777	56	42	153,867	64	0
College	139	93	76,475	311	102	1,181,173	88	13.8
Federal	108	75	49,130	274	95	1,025,806	98	7
State and local	801	177	51,341	195	75	777,352	94	5.2
Other	95	41	45,916	426	103	1,651,263	104	7

Population data reflects the number of utility customers in the population by business type. Entries in the sample column represent the number of utility customers in the sample. All other data items are averages for the appropriate business categories. Both sample and population reflect commercial sector electric customers in the LIPA service area with average daytime hourly electricity use greater than 20 kW.

contacts to agents with onsite energy engineering capabilities result in immediate attainment of the knowledge threshold and a purchase decision using the agent's hourly energy use data and payback requirement. Agents with no onsite energy management expertise are moved a single step in the knowledge acquisition process as the result of each sales contact. Additional sales contacts move agents to the next knowledge acquisition state, up to one level below the threshold. The observation of a neighbor's CHP installation is required for an agent with no onsite expertise to reach the purchase decision threshold.

Each agent's knowledge state increases with the installation of a CHP system in its neighborhood defined by the same business type and similar size. The impact of a CHP system installation results in an endogenously determined "spread" of the technology to other agents in the same neighborhood. These "observed" technology installations are the last step in knowledge acquisition required by agents with no onsite engineering expertise.

The following three CA parameters define the diffusion dynamics described above: (1) the number of knowledge states, k, required to reach the threshold level, (2) the number of agents in a neighborhood, p, and (3) the number of sales contacts per year, s.

3.2. Evaluating aggregate diffusion impacts

The question addressed in this analysis is: To what extent can discriminatory standby rates reduce the diffusion of CHP technologies? While standby rates set at levels greater than the cost of providing intermittent CHP-related service undoubtedly reduce economic efficiency and energy cost savings associated with CHP systems and inhibit CHP diffusion, it is not clear how important this factor is, especially in comparison to other inefficiencies and

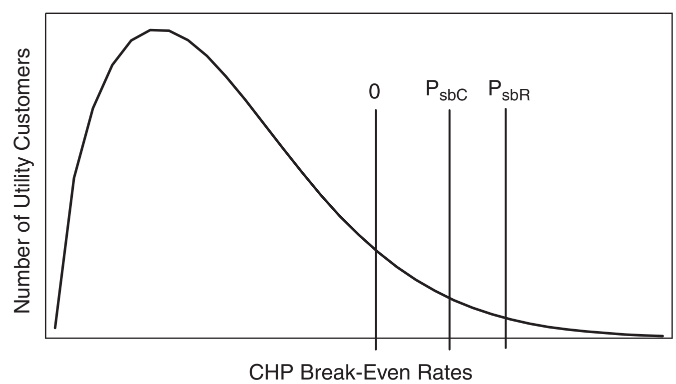

Fig. 1. Population distribution, $f(x)$, of CHP standby break-even rates.

problems that exist in the regulated electric utility industry.[11]

The potential diffusion impact of an inflated standby rate based on maintaining utility revenue, P_{sbR}, is illustrated in Fig. 1 where the population distribution of CHP standby break-even rates is shown along with a cost-based standby rate, P_{sbC} and a standby rate of 0. The distribution of utility customer energy use characteristics yields a distribution of break-even rates that is approximately lognormal with utility customers to the right of any standby rate achieving positive annualized CHP savings (or a positive net present value). Utility customers to the left of 0 require a subsidy to achieve positive annualized savings. We assume in this representation that the break-even population distribution, $f(x)$, represents all of the economic factors associated with a CHP investment except the

[11]For example, US Costs of the August 2003 Northeast blackout have been estimated at between \$7 billion and \$10 billion (ICF Consulting, 2003).

standby rate and that the capital recovery factor in this representation reflects a social discount rate. It follows that $D(P_{\mathrm{sbR}}) = \int_{P_{\mathrm{sbR}}}^{\infty} f(x)\,\mathrm{d}x$ is the long run maximum economically efficient adoption of CHP technologies under the current rate, $D(P_{\mathrm{sbC}}) = \int_{P_{\mathrm{sbC}}}^{\infty} f(x)\,\mathrm{d}x$ is adoption under a cost-based standby rate and $D(0) = \int_{0}^{\infty} f(x)\,\mathrm{d}x$ is adoption with no standby rate. Additionally, $D(0) > D(P_{\mathrm{sbC}}) > D(P_{\mathrm{sbR}})$. These economic potential estimates provide an upper-bound estimate of potential CHP penetration and energy savings in the long run; however, they do not reveal the dynamics of new technology diffusion required to compute the present value of costs and benefits. Since the diffusion of new CHP technologies could conceivably take a decade or two, diffusion dynamics can have a significant impact on discounted cost/benefit analysis.

CHP market diffusion is a product of the maximum economic potential $D(.)$ and, γ, the fraction of economic potential achieved as a function of agent population characteristics, α (including hourly energy use, payback requirements, and CHP system characteristics), time, t, the standby rate, P_{sb}, and the three CA diffusion parameters defined in the previous section: k, p and s. That is

$$\mu(\alpha, t, P_{\mathrm{sb}}, k, p, s) = \gamma(\alpha, t, P_{\mathrm{sb}}, k, p, s) D(P_{\mathrm{sb}})$$
$$= \gamma(\alpha, t, P_{\mathrm{sb}}, k, p, s) \int_{\mathrm{Psb}}^{\infty} f(x)\,\mathrm{d}x, \tag{2}$$

where $\mu\,(t, P_{\mathrm{sb1}}, k,p,s) > \mu\,(t, P_{\mathrm{sb2}}, k, p, s)\,\gamma$ when $P_{\mathrm{sb1}} < P_{\mathrm{sb2}}$ and $\gamma(t, P_{\mathrm{sb1}}, k, p, s) > \gamma(t, P_{\mathrm{sb2}}, k, p, s) \leqslant 1.0$.

The impact of excessive standby rates at period t in the forecast horizon, given a current standby rate P_{sbR} , a cost-based rate P_{sbC}, and diffusion parameters k, p, s, is

$$\mu(\alpha, t, P_{\mathrm{sbC}}, k, p, s) - \mu(\alpha, t, P_{\mathrm{sbR}}, k, p, s) \tag{3}$$

represented as the vertical distance between the two curves shown in Figs. 2 and 3. Fig. 3 shows a scenario with an alternative set of diffusion parameters k, p, s (2).

The total direct economic cost imposed on CHP utility customers and potential CHP customers (EC) is the

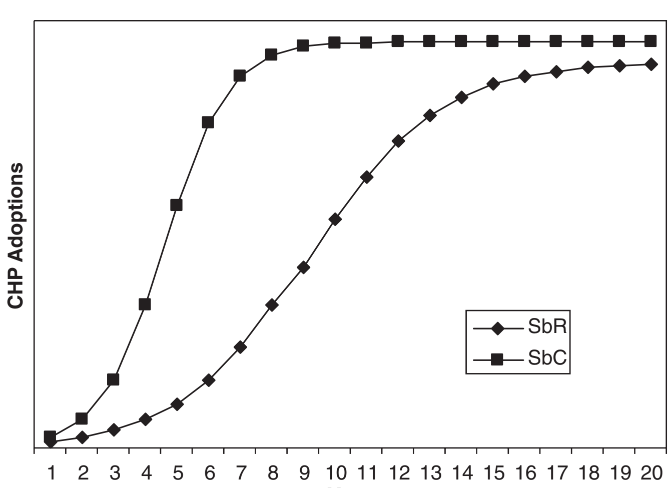

Fig. 2. Diffusion process d1.

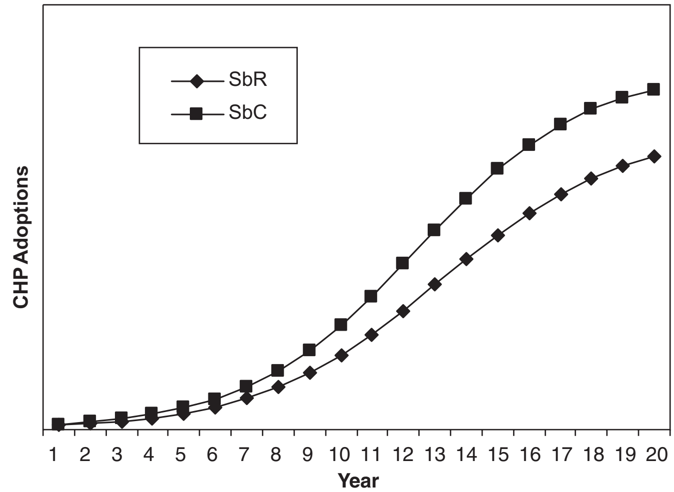

Fig. 3. Diffusion process d2.

difference in the present value of the energy cost savings under current standby rate P_{sbR} , and cost-based rate P_{sbC}. given as

$$\mathrm{EC}(T) = \int_0^T [\pi(\alpha, t, P_{\mathrm{sbC}}, k, p, s)\mu(\alpha, t, P_{\mathrm{sbC}}, k, p, s)]$$
$$-(\alpha, t, P_{\mathrm{sbR}}, k, p, s)\mu(\alpha, t, P_{\mathrm{sbR}}, k, p, s)]\mathrm{e}^{rt}\,\mathrm{d}t, \tag{4}$$

where π (.) is the average system energy cost savings and r is the social discount rate.

These two figures illustrate that the economic costs associated with excessive standby rates depend critically on the underlying diffusion process. The reasonably speedy diffusion in Fig. 1 shows a significant impact while the diffusion process in Fig. 2 shows a much smaller total impact because most savings occur in future years that are discounted more heavily.

The model developed in this study provides ex ante forecasts of market diffusion, μ (α, t, P_{sbC}, k, p, s), and discounted energy cost savings, EC(T), as the sum of individual agent technology installations. The difference in the current standby rate and cost-based standby rate scenarios depends on standby rates (P_{sbR}, P_{sbC}) and the CA diffusion parameters, k, p, s.

The following section describes the methodology used in this study to isolate the impact of standby rates from impacts of the diffusion parameters as part of a formal hypothesis test.

3.3. Testing the standby-rate hypothesis

Since values for elements of the CA parameter vector, k, p, s are unknown in this ex ante application, we approach the quantitative analysis as a field experiment. Our experimental units or subjects are actual commercial utility customers in a study area who accumulate knowledge required to make a CHP investment decision according to the CA process defined by the k, p, s parameter vector. The response variable is the discounted cost of excessive standby rates. A factorial experimental design identifies n treatment combinations of the parameter values that can be applied with the agent-based microsimulation model. For each parameter vector associated with one of the n treatments, the model is simulated once with the current standby rate P_{sbR} and once with a cost-based rate P_{sbC} to determine net diffusion impacts of excessive standby rates as indicated in (3) and (4).

In the spirit of an experimental approach, we specify a null hypothesis, H_0: Differences between current standby rates and cost-based rates result in no significant costs to utility customers. If all n experimental treatments show insignificant impacts the null hypothesis cannot be rejected. If treatment results are mixed, the analysis must turn to an exploration of circumstances represented by CA parameter vector values that lead to significant costs.

On the other hand, if all n treatments show significant diffusion impacts, H_0 can be rejected indicating significant standby rate impacts on CHP diffusion in the study area. In this case the n quantitative results will provide empirical estimates of the likely range of costs.

As with other experiments, the validity of the results depends on the design of the experiment and the extent to which the experimental treatments isolate the relationship of interest. In this case, the specification of the CA process γ must be consistent with actual information dissemination and knowledge accumulation and the k, p, s parameters must map CHP diffusion, μ, onto all reasonable empirical representations.

4. Empirical model specification, input data and parameters

4.1. Application area

Inter-utility variations in rate structures, natural gas prices and utility customer heterogeneity in electric and thermal load profiles require utility-specific analysis of CHP diffusion. The Long Island Power Authority (LIPA) utility service area was selected as the application area for this study. LIPA is a New York state authority that was created to close the Shoreham Nuclear Power Plant. LIPA took over LILCO, the Long Island utility that owned Shoreham, in 1998 and now operates Long Island's retail electric system. As a public entity, LIPA does not earn profits; however, it and other public electric utilities, apply the same principles as investor-owned utilities in operating their systems and designing customer rates. The service area includes most of Long Island and serves a population of 2.8 million (Long Island Power Authority, 2004). LIPA is a "load pocket" with limited transmission capacity onto the island. LIPA faces high marginal distribution costs, chronic generating capacity shortfalls, reliability difficulties, and moderate economic growth. LIPA could potentially realize significant benefits from a more decentralized energy delivery system.

4.2. CHP systems

Natural gas engine-driven systems, the most common CHP system, are sized for each agent to provide optimal outputs of electricity and thermal loads according to each facility's whole building hourly electric loads, air conditioning hourly electric loads and hourly thermal loads for domestic water heating and space heating. All data on CHP systems was taken from a US Department of Energy (DOE, 2002) study and included total installed cost, operating and maintenance costs, air conditioning operating, maintenance and equipment costs and efficiency characteristics for a variety of system sizes.

Agent valuation of grid attributes relative to CHP attributes not included in the CHP cost items above should be added to these costs. For instance, extended warranties would provide an additional cost. Similarly, an agent's valuation of improved power quality would reflect a negative cost. No quantitative information exists on the valuation of these items; consequently, only the costs included in the DOE, 2002 study are used to compute CHP system costs. However, two alternative simulations are included in the analysis to test the sensitivity of analysis results to increased CHP cost estimates.

4.3. Utility customer data

Utility customer survey data from the US Department of Energy's Commercial Buildings Energy Consumption Surveys (CBECS) for 1992 and 1995 were used to develop a sample of buildings representing commercial utility customers, or agents, on Long Island. Data were pooled, and a proportional poststratification using US Commerce Department (County Business Patterns, 2000) county-level data on establishments by employee size categories was used to develop a sample of 1549 buildings reflecting the population of commercial buildings on Long Island potentially suitable for CHP technologies.[12] Characteristics of the customer sample are presented in Table 1.

The one item missing from the CBECS-based agent sample data is an investment criterion. Values for this missing data item were imputed for each agent record using survey results for 2400 Arkansas commercial sector utility customers. The 1994 Arkansas survey asked a question designed to elicit the willingness of decision makers to trade off future savings for current investments. The average payback requirement of this sample is 1.5 years, consistent with the 1.4 year firm average reported in Anderson and Newell (2002). Values for the missing CBECS payback variables were developed with a "nearest-neighbor" imputation approach that makes a random draw from

[12]Commercial utility customers were considered potential adopters only if they used more than an average of 20 kW for each hour during the day. This size includes office, retail and other commercial buildings larger than about 10,000 square feet along with most high electric intensity establishments such as restaurants and grocery/convenience stores.

the Arkansas survey responses in a neighborhood defined by the agent's business type and size as measured by the number of employees. Since each agent, i, in the microsimulation sample reflects an additional w_i agents in the population determined by the weight associated with that agent, an additional w_i agents are generated for each of the 1549 original agents. Each agent in the w_i subset is identical except that payback requirements are determined with random draws from appropriate neighborhoods in the Arkansas survey. This process provides 12,912 agents for the microsimulation process.

4.4. Rebound effect

Agents who adopt CHP systems realize energy cost savings equivalent to that provided by an increase in equipment efficiency, resulting in increases in energy consumption. This efficiency-related response, or "rebound" effect, is generally assumed to be similar in total impact to the short-run price elasticity (Greening and Difiglio, 2000). The commercial building energy services rebound elasticity is estimated to be −0.15 in the US Department of Energy's NEMS model (DOE, 2004). This rebound price impact is applied as a partial-adjustment process with a short-run (1st year) elasticity of −0.075 and a long-run elasticity of −0.15. This adjustment reduces CHP energy cost savings.

4.5. Utility rates

The LIPA Large General Service (LGS) and Standby rate class schedules (Long Island Power Authority, 2004) were applied to model electricity costs for each of the agents. Basic LGS rates are differentiated by season with charges of $0.0928/kWh and $9.99/kW in the summer (June–September) and $0.0779/kWh and $8.88/kW in the winter (January–May and October–December). The demand charge ($/kW) is based on the maximum electricity use in any 15-min period in the month. The standby charge is composed of both "contract" and "as needed" charges with a total charge of $4.92/kW applied to the maximum 15-min demand charge occurring in the current or previous eleven months.[13] A 2004 natural gas price of $8.30 per million Btu was used in the analysis.[14]

The number of LIPA commercial utility customers is assumed to grow by 1 percent per year over the forecast horizon. This rate of growth is consistent with the 2-percent rate of electricity use growth in the commercial sector reported in the LIPA Energy plan.[15] A sample of new agents is developed for each forecast year. The new construction sample is composed of recently constructed buildings from the original survey data weighted to reflect the appropriate number of new utility customers.

4.6. Alternative cost-based standby rates

Under the baseline scenario presented in the next section, the average CHP system size is 92 kW (about 15 times the peak kW use of an average residence). The small size of new CHP systems, the random nature of likely unexpected CHP downtimes and spatial clustering of commercial establishments permits a probabilistic approach to determining the cost of providing unexpected energy and demand services to CHP service during unexpected systems downtimes.

Most CHP prime mover specifications report average downtimes of less than 10 percent. By scheduling required maintenance during off-peak periods, unanticipated interruptions should be no more than 10 percent during periods where capacity limits are approached, consequently, an estimate of least cost backup rate schedule for widely-distributed small CHP systems is specified as 10 percent of the standard large general service demand charge plus standard energy charges for kWh use to cover variable costs. Resulting $0.999/kW summer and $0.888/kW winter peak demand rates are substantially less than the current LIPA rates of $4.92/kW. One important distinction between these rates is that the probabilistically determined rates require a sufficient (future) population of CHP systems to take advantage of the random nature of unexpected outages while the LIPA rate is an attempt to reflect costs given the current population of CHP systems. A "chicken and egg" problem exists here with CHP advocates arguing that long-run system cost optimization can be achieved only with current pricing that represents these longer-run conditions. Not surprisingly, utilities are more concerned with immediate revenue and revenue neutrality issues. The long-run standby rate argument is appropriate only if these rates result in the kind of clustered, small CHP population characteristics assumed above.

The issue of long-run system cost optimization mentioned above is a reminder that appropriate standby rate design should take into account all of the costs and benefits associated with CHP systems including avoided transmission and distribution costs, emissions reductions and grid stability. The methodology developed in this study can be extended to incorporate these items; however, their consideration is beyond the scope of the current study. The focus at this time examines the impact of the difference

[13]The "as needed" demand charge of $2.46 is applied to actual maximum kW use during an interruption in CHP service; however, the twelve month "ratchet clause" insures that one unanticipated 15-min CHP outage will trigger this charge for an entire year.

[14]2004 prices are used in this study as reasonable representations of longer-term natural gas prices based on current Department of Energy Mid-term forecasts. Additionally, the primary focus of this study is on the impacts of standby demand charges, which are not tied to natural gas prices.

[15]Commercial sector electricity demand increases over time as a result of new commercial construction and increases in electricity intensity over time, primarily caused by increased use of computer, office and other miscellaneous equipment (Jackson, 1986, 1994).

Table 2
CHP adoption summary results[a]

	Adopters	Simulation year CHP kW capacity	Current LIPA rates Annual CHP savings (million \$)	Adopters	CHP kW capacity	Cost-based rates Annual CHP savings (million \$)	Adopters	CHP kW capacity	Difference Annual CHP savings (million \$)
Baseline scenario									
5	14	47,869	86	419	169,838	212	405	121969	126
10	84	92,218	146	1962	260,662	313	1878	168444	167
15	526	163,551	212	2664	276,039	331	2138	112488	119
20	782	176,746	274	2806	276,289	356	2024	99543	82
25	913	178,167	289	3012	276,213	384	2099	98046	95
Alternative scenario 1									
5	3	17,651	23	130	76,812	110	127	59161	87
10	20	57,042	99	470	167,464	220	450	110422	121
15	32	69,362	118	818	198,023	259	786	128661	141
20	40	72,773	124	1156	210,103	283	1116	137330	159
25	43	75,120	129	1324	212,161	295	1281	137041	166
Alternative scenario 2									
5	2	14,708	25	93	64,750	83	91	50042	58
10	4	32,048	57	181	101,991	147	177	69943	90
15	17	50,707	93	255	127,697	191	238	76990	98
20	23	56,320	101	290	132,431	197	267	76111	96
25	25	58,014	103	308	133,502	202	283	75488	99

Cellular automata parameters for alternative forecasts

	Baseline	Alt 1	Alt 2
Knowledge levels	5	8	12
Neighborhood size	80	40	20
Increase in sales contacts (%)	50	10	0

Cellular automata parameters values used in factorial experimental design

Knowledge levels	2, 5, 8, 12
Neighborhood size	20, 40, 80, 100, 200
Increase in sales contacts (%)	100, 50, 10, 0

[a]LIPA LGS electricity rates for 2004 include demand charges of \$9.99/kW summer (June–September) and \$8.88/kW winter and energy charges of \$0.0928/KWh and \$0.0779/KWh summer and winter, respectively. Standby demand charges are \$4.92/kW according to the current tariff and \$0.999/kW summer and \$0.888/kW winter for the cost-based rates.

between the current LIPA standby rate and a long-run cost-based CHP rate[16] with respect to the diffusion of CHP technologies.

5. Analysis results

The experimental design used to "net-out" the impact of alternative standby rates includes four knowledge levels, five neighborhood sizes and four annual percentage increases in sales contacts to describe possible empirical representations of information dissemination and knowledge accumulation for a total of 80 experimental treatments (See Table 2). Experiment results indicate that the \$4.00/kw/month differential between current standby rates and the cost-based estimate of cost of service have a significant impact on CHP diffusion and utility customer energy costs.

Results of three of the experimental treatments are included in this section. A "most likely" baseline scenario was selected to reflect the general utility industry view of a slow (20 year) market penetration scenario, given current standby rate specifications. Diffusion paths with slower penetration showed the smallest cost impacts; consequently, results of the slowest penetration treatment considered feasible are included to show the most limited impact. An additional forecast with a diffusion path between the baseline and the slowest diffusion path is presented to illustrate results between the moderate and the slowest case.

The baseline CA specification required agents to pass through five stages of knowledge accumulation and sales contacts were allowed to grow at a rate of up to fifty percent per year. Neighborhoods included eighty agents closest in total employment within the same business

[16]The long-run rate is defined as reflecting the system cost of providing generation and distribution capacity to a sizeable number of appropriately clustered CHPcustomers.

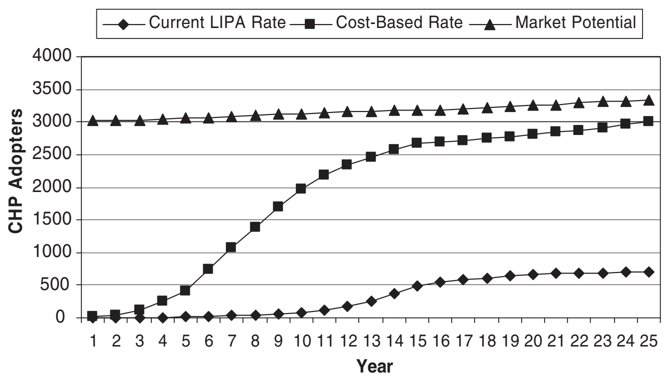

Fig. 4. Number of utility customer adopters—baseline scenario.

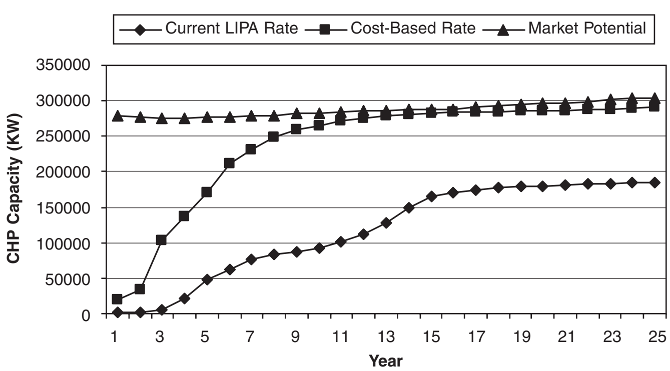

Fig. 5. CHP generating capacity—baseline scenario.

category. The model was run with current LIPA standby rates and cost-based rates described in the previous section. The resulting forecasts are shown in Figs. 4 and 5. The "current LIPA rate" series shows the diffusion of the number of CHP systems and the diffusion of CHP kW capacity (total avoided central plant kW of all CHP systems) under current LIPA standby rates for a 25 year horizon. Approximately 20 years are required for CHP technologies to approach their asymptotic values under current LIPA standby rates.[17] CHP capacity increases more rapidly than number of installations because early adopters tend to have larger facilities. Greater new technology adoption by larger firms has been noted in previous studies and attributed to many factors[18]; however, the impact of sales activity targeted to larger customers and the higher proportion of large customers with onsite energy engineering expertise are sufficient here to provide similar empirical results.

The "cost-based LIPA rate" series show number and kW capacity of CHP systems under the cost-based rate described above. The difference between the "current LIPA rate" and "cost-based LIPA rate" series shows the impact of excessive standby rates (relative to the long-run cost-based rates). These model forecasts indicate that switching to cost-based rates would generate an additional 115,000 kW of customer-generated power by the fourth year. This capacity is comparable to the size of a small central generating plant and is accompanied by an approximately equal amount of heat energy supplied for space heating, water heating and other thermal loads rather than being exhausted to the environment. The difference between the current and the cost-based standby rate scenarios increases to approximately 170,000 kW in year nine.

The "market potential" series in the figures shows CHP installations that would be installed if all utility customer agents immediately reached the knowledge threshold required to make a purchase decision.[19] This market potential is considerably smaller than the "technical potential" measures used in most studies because agents in the current model adopt CHP systems only if the payback meets each agent's criterion, which, as indicated earlier varies across agents with an average of about 1.5 years. By comparison, the DOE, 2002 study used a 10-year payback criterion to evaluate CHP potential. Under current LIPA rates, about 28 percent of potential sites, representing approximately 60 percent of potential CHP kW capacity, undertake a CHP installation in the 25-year forecast. Under this diffusion path most smaller agents are not "found" by sales targeting activities and do not have sufficient knowledge to initiate the purchase process themselves. Under the cost-based standby rates most of the market potential is realized (90 percent of potential sites representing 96 percent of potential CHP capacity).

Evaluating energy and cost impacts for slower and less complete diffusion scenarios also shows significant standby rate impacts as indicated by the two pairs of curves in Fig. 6 (the area between the current and cost-based rates for each alternative scenario shows the rate impact). Neighborhood size and rate of increase in sales contacts were reduced and number of sales contacts required to reach the knowledge threshold was increased to provide slower diffusion paths (see Table 2). These parameter changes substantially reduced the total adoption of CHP technologies. Under the slowest diffusion scenario, an average of one system adoption occurs per year through the forecast period with only the largest, and most profitable, project undertaken. About 20 percent of the potential kW capacity is actually achieved.

[17] These are technically not asymptotic values because the stock of agents grows each year; consequently, all of the series have an upward trend over time.

[18] Easier access to capital markets, better financing rates, and more sophisticated decision-making have been identified in previous analysis. Sales targeting large customers is an obvious supplier profit-maximizing strategy that has been observed in the CHP market (Jackson, 2005).

[19] By way of reference, this maximum market potential is a relatively small fraction (10 percent) of total LIPA commercial customer kW capacity requirements.

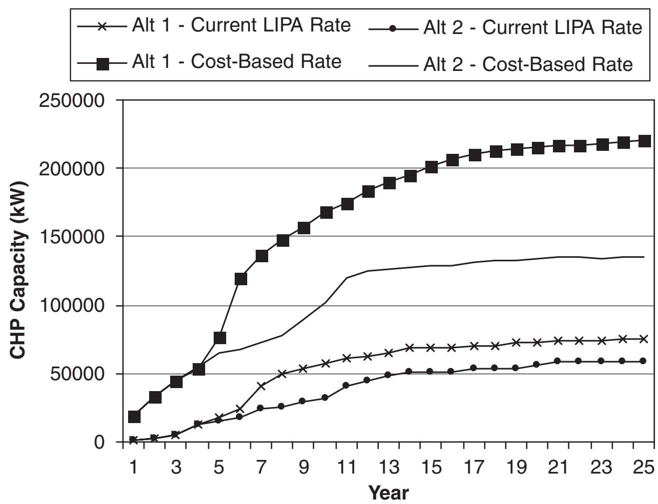

Fig. 6. CHP generating capacity—alternative CHP diffusion scenarios.

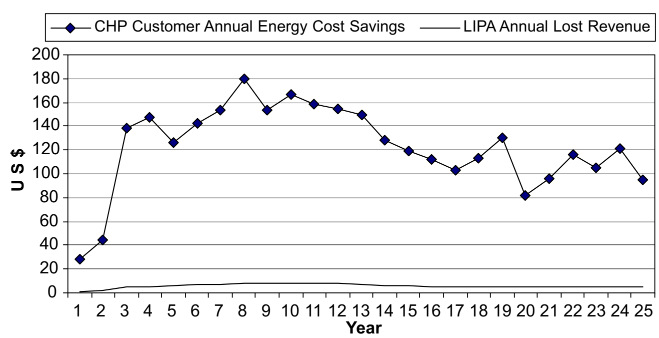

Fig. 7. CHP customer energy cost savings and LIPA lost revenue.

Fig. 7 shows baseline energy cost savings for CHP customers along with utility revenue losses resulting with a cost-based rate. Utility customer savings reach an annual peak of $180 million (US) while LIPA utility losses are no more than $8.3 million. The discounted annual savings in utility customer energy costs is $ 2137 million over the 25 year period while utility lost revenue is $ 99 million. That is, revenue neutrality could be achieved and still provide a net savings to utility customer of $ 2038 million with a cost-based rate.

The results of all 80 simulations show that diffusion impacts are less with a slower diffusion process. Fig. 6 shows that the slowest diffusion treatment results in 70,000 kW of unachieved CHP capacity. The discounted utility customer annual savings in this minimum impact scenario show is $ 1361 million over the 25 year period while utility lost revenue is $ 51 million.

One of the most interesting findings of this agent-based analysis is that the application of current LIPA standby rates is likely to keep the population of CHP customers small enough to limit the "neighborhood" information dissemination and knowledge acquisition impacts and to prevent the achievement of a sufficient number of clustered CHP applications required to take advantage of the probabilistic nature of unexpected CHP downtimes. However, when standby rates are specified to reflect the advantages of a large number of clustered applications, the adoption required to match this premise is likely to be achieved.

These and similar results from all 80 experimental treatments determined with the factorial experimental design indicate that regardless of the diffusion process excessive standby rates, relative to their long-run cost-based values, can be expected to have a significant impact on the diffusion of CHP technologies, to limit the value of the random nature of unexpected CHP downtimes to the utility system and to impose considerable costs on customers who would have adopted these technologies.

To examine sensitivity of the results to increased initial CHP costs reflecting agent valuation of grid attributes and other factors, DOE (2002) cost estimates were increased in two alternative simulations. An initial system cost increase of 20 percent reduced the number of systems to 75 percent and the total kW CHP capacity to 84 percent of the baseline. Initial system cost increase of 40 percent reduced the number of systems to 52 percent and the total kW CHP capacity to 66 percent of the baseline. These results indicate that any reasonable agent valuation of grid attributes will not change the analysis conclusions.

It also should be noted that CHP-related distribution system and emissions benefits have not been included in this analysis; monetization of these benefits in the form of incentives to CHP customers would increase the CHP diffusion and capacity contributions beyond the baseline results.

6. Summary and conclusions

The extent to which combined heat and power (CHP) technolgy diffusion is limited by current regulatory practices as opposed to reflecting traditional new technology diffusion and energy-related investment patterns has important policy implications. CHP systems can potentially offer a significant opportunity to improve energy efficiency and reduce emissions.

This study develops and applies a new analytical framework to separate the impacts of standby rates from the diffusion process. The modeling methodology extends microsimulation techniques to include endogenous agent interaction with a cellular automata process that reflects the dissemination of new technology information and the accumulation of knowledge required to consider the purchase of these technologies. By viewing each simulation of the model as an experimental treatment where alternative values of neighborhood size, knowledge levels and sales activity are developed with a factorial experimental design, the analysis is able to systematically separate the impacts of standby rate differentials from the underlying diffusion process for alternative diffusion paths.

The Long Island Power Authority (LIPA) service area was selected to conduct an example analysis. Results for the LIPA study area find that excessive current standby rates can be expected to significantly reduce the diffusion of new CHP technologies regardless of diffusion dynamics. Total additional costs attributable to excessive standby rates are estimated to be $2.1 billion over 25 years under a baseline scenario and $1.4 billion under the least costly alternative diffusion scenario examined in the study.

Similarity in relationships between the LIPA study area and utility service areas in California and the Northeastern states suggests that analyses of these service areas are likely to show similar results with the following important policy implications. Standby rates designed to achieve immediate utility rate revenue neutrality or to reflect immediate, rather than longer run, distribution benefits are likely to limit the diffusion of CHP systems to such an extent that customer and utility system benefits of a large number of spatially clustered small systems are never realized. The costs of these shortsighted rate design objectives are substantial both in terms of electric system efficiency and energy costs for potential CHP customers.

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