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Community-Scale Energy Supply and Distribution Optimization Using Mixed-Integer Linear Programming

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ABSTRACT

Community-scale energy planning represents a multidiscipline problem involving the competition of many economic, environmental, energy security, and logistical requirements. This complex problem is routinely faced by U.S. military installations, both domestic and abroad, and can result in unnecessary financial and personnel costs if a suboptimal solution is chosen. In response to this problem, the U.S. Army Corps of Engineers (USACE) has developed a community-scale, mixed-integer linear programming (MILP) based model to assist in the selection of energy supply and distribution equipment and to determine optimal schedules of operation. The model was developed to minimize the total annual equivalent cost of providing thermal and electric power to clusters of buildings by selecting from existing or potential equipment using a fully centralized, fully decentralized, or hybrid approach, while meeting all other required constraints. This paper describes the model (with an emphasis on its unique elements in relation to similar existing models), its limitations, and considerations for future work.

INTRODUCTION

All federal entities are required by law to eliminate fossil-fuel use in new and renovated facilities by 2030 and to reduce overall facility energy usage by 30% by 2015 (Energy Policy Act [EPACT] 2005; U.S. Energy Independence and Security Act [EISA] 2007). Furthermore, the Army has set goals to achieve 25 net-zero energy installations by 2030. Compliance with the law and achievement of these additional goals will require an enormous commitment of both time and resources to improve the current infrastructure. This cost can be significantly reduced by approaching the problem systematically and making use of the institutional knowledge that is developed by a research team in assisting many installations with the same basic problem. This was the rationale that motivated the funding of the Net Zero Energy Installations Project (NZEI) by the Army Corps of Engineers. The NZEI project, funded in 2010, focused on developing the tools and processes needed to assist in community/installation-scale energy planning. The project draws heavily from the extensive work that has already been done in this area, including work done through the International Energy Agency's (IEA's) Energy Conservation in Buildings and Community Systems Annex 51 (Jank 2011; Robinson et al. 2009; Robinson et al. 2007; Yamaguchi and Shimoda 2010). This community-scale process, described in previous publications (Zhivov et al. 2010, 2013), consists of four major steps: (1) gather site information and develop a baseline, (2) reduce building energy loads, (3) optimize energy supply and distribution, and (4) provide decision support and project recommendations. This paper describes the third step.

A review of the literature shows that a significant amount of work has been done on the modeling and optimization of the energy generation and conversion systems that are present in central thermal and/or electrical plants (Chinese 2008; Bojic and Cubrovic 2010; Rubio-Maya et al. 2011; Liu et al. 2007; Liu et al. 2009; Prousch et al. 2010; Sakawa et al. 2002; Park et al. 2009; Serra et al. 2009). Many of the early models were based on linear programming, but recent work has favored mixed-integer linear programming. This change allows the models to capture the effects of economies of scale and to provide greater control over the operation of the conversion options (only allowing operation with a reasonable power range, e.g., 70%–100% of the maximum capacity). These

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models have been applied to municipal energy systems (Bojic and Cubrovic 2010; Rubio-Maya et al. 2011; Prousch et al. 2010; Sakawa et al. 2002; Park et al. 2009), industrial polygeneration (Liu et al. 2007; Liu et al. 2009; Serra et al. 2009), and renewable energy focused systems (Razak et al. 2007; Chinese and Meneghetti 2005; Schulze et al. 2008). Additionally, significant work has been done to model and optimize distribution networks for various pipeline-based utilities (Dong et al. 2012; Söderman and Pettersson 2006; Weber et al. 2005, 2007; Weber 2008; Chan et al. 2007). Most of this research has focused on network layout and pipe diameter sizing in which the size and location of the generation and conversion options are fixed (Dong et al. 2012; Söderman and Pettersson 2006; Chan et al. 2007). Almost all of these models assume a centralized solution using a district plant and strive to find the optimal configuration of that solution. However, there is a current need to quantitatively evaluate centralized, decentralized, and hybrid energy systems and to find the optimal system among them for any given community. Recently several groups have worked towards the optimization of energy supply and distribution networks simultaneously (Dong et al. 2012; Söderman and Pettersson 2006; Weber et al. 2007; Chan et al. 2007). Most of these models (Dong et al. 2012; Söderman and Pettersson 2006; Chan et al. 2007) allow shortest-distance placement of the pipe segments during the optimization process, and may therefore only be useful when planning construction on greenfield land. Pipeline location restriction has been discussed in the literature (Weber et al. 2007) and initial implementation has been reported for a single project (Weber et al. 2007). However, none of these models have presented results for the optimization of supply options and distribution networks that serve large numbers (>20) of buildings. This paper summarizes an attempt to solve a community-scale problem using MILP in a hybrid approach where the design space includes centralized energy-conversion options, predefined hot and cold water distribution networks, and decentralized options.

The design of community-scale energy supply and distribution systems requires consideration of the potential energy flows between many different devices and loads. Descriptions of the common design considerations in the literature (Chinese 2008; Liu et al. 2009) include meeting the heating, cooling, and/or electric loads at all times while sizing baseload and peaking equipment; minimizing source or site fossil fuel energy; and providing energy security and redundancy. However, the energy generation and distribution systems used on military installations are subject to two additional sets of requirements that may not be present when addressing nonmilitary community-scale problems. These include the following:

1. Energy infrastructure redundancy to ensure continuous operations (potentially including both thermal and electric loads).
2. Legislative requirements on installation-wide renewable energy production; energy reduction; greenhouse gas emissions; and Army net-zero energy goals.

Redundancy and legislative requirements must be met in any acceptable solution, but they vary between Army installations; the model must allow for this variation. Additionally, there is a desire to make the model as flexible as possible so that it can be used to screen new and unusual technologies for installations in any given climate zone. Lastly, there is an ongoing policy debate as to whether the Army should seek out and endorse a one-size-fits-all centralized or decentralized solution that would be nearly optimal for all installations. Though it seems unlikely that such a singular solution exists, there is currently no quantitative method in place for quickly testing various infrastructure scenarios on any given installation. This paper presents a new model based on these considerations. The following section presents the superstructure and mathematical representations of the model. The Example Study section presents results from applying the model to a building cluster example based on installation data and discusses the results and the model.

MODELING APPROACH

Superstructure Representation

Figure 1 shows a generalized superstructure representation of the model. The model, kept intentionally abstract, consists primarily of matter and energy flows that originate at the sources, experience some conversion by the selected options, and, finally, satisfy the load requirements. These sources can be on demand (such as natural gas or grid electricity usage) or intermittent (such as wind power or solar irradiation). The conversion options currently fall into three groups: (1) direct-conversion options, (2) intermittent renewable options, and (3) storage conversion options. Direct conversion options take in one of the flows and convert that flow into one or more other flows within a single time step (e.g., boiler, chiller, reciprocating engine). Intermittent renewable options make use of predicted power or heat output data for each option considered (e.g., photovoltaic system, wind turbine, solar thermal system). Storage conversion options can convert between different flow types as well, but have the additional ability to store the output for use in a later time step (e.g., hot and cold water storage tanks, batteries, hot and cold water distribution networks). Appendix A provides the direct conversion, intermittent renewable, and storage conversion options considered in the example study, along with their related parameters. The separation of conversion options into three distinct classes allows greater model flexibility without a great sacrifice to the computation time. This distinction is further discussed in the Mathematical Model section. The loads can represent almost any quantity that is relevant to community planning as long as the flows are carefully defined, the units are consistent, and sufficient options are presented to meet the loads. Example loads include heating, cooling, electric, potable water, sewage, and solid waste.

Figure 2 shows an example superstructure that describes the model in a more concrete way. This superstructure shows a snapshot of some of the technologies and flows currently considered by the model. In this example, a single central plant is shown with the capability to serve the heating, cooling, and electric loads of a single building cluster through either new or existing utility networks. Alternatively, the loads can be met by distributed equipment that would be present at the building level. This equipment, shown in Figure 2 as distributed boilers and distributed chillers, represents groups of boilers and chillers that have been individually sized ahead of time and then parameterized as single option models for the optimization. This superstructure allows the selection of a fully centralized, fully distributed, or hybrid system. Though a relatively simple superstructure example is presented here, the generality of the model allows for any number of conversion options, central plants, utility networks, and loads.

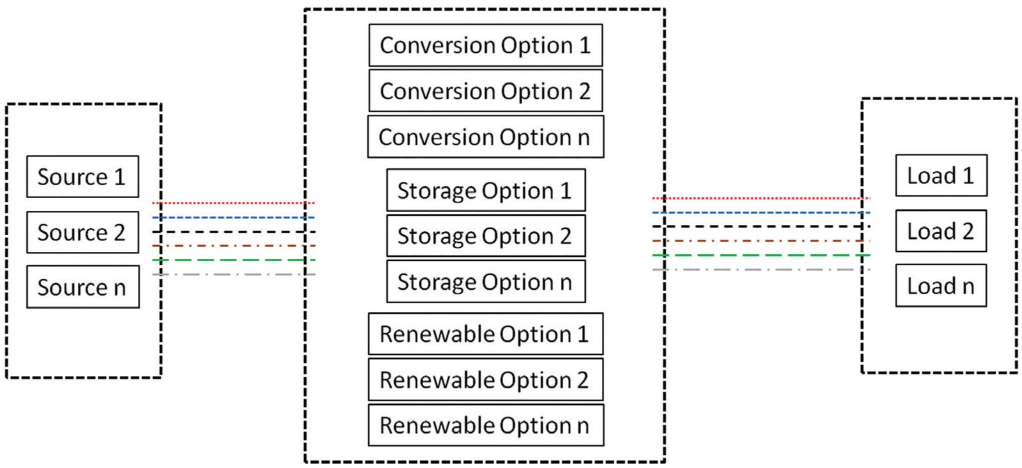

Figure 1 Generalized superstructure representation of the model. The lines indicate matter and energy flows between the sources, options, and loads.

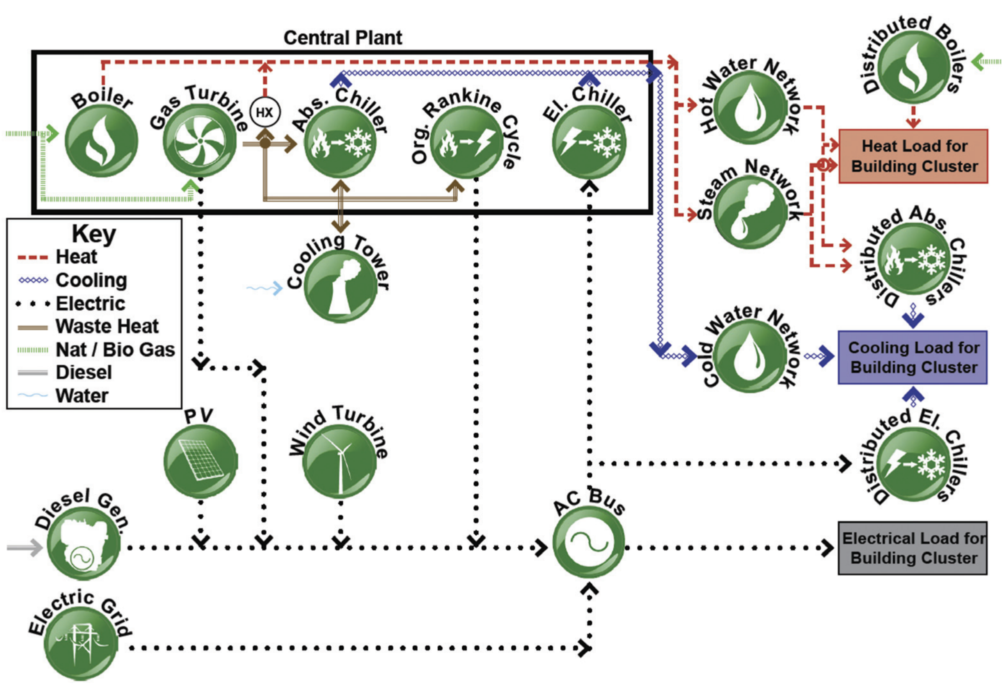

Figure 2 Example superstructure with sample flows and technology options.

Furthermore, the conversion options and networks considered can consist of both existing and proposed infrastructure. The only requirement is that each of the options be fully defined with parameters that are described in the mathematical model section.

Mathematical Model

The following model is proposed and tested for the structural and operational optimization of a community energy supply and distribution system. The model requires, as inputs, interval-based heating, cooling, and electric load data that represents a typical year for each cluster. It also requires characterized potential distribution networks and conversion options for the optimization's selection. Fuel rates, electrical energy and demand charges, and an annual interest rate are also required.

SETS

T = set of all time steps

M = set of all months

DCO = set of direct conversion options

RO = set of intermittent renewable options

SCO = set of storage conversion options

F = set of all possible fuels

EDC = set of electric demand charges

NGDC = set of natural gas demand charges

OS = set of all option sets. This set has three members (DCO, RO, and SCO)

GO = set of generic options (this set can be used in lieu of any of the three options sets (DCO, RO, and SCO). It is used in equations that apply to more than one of the option sets).

INDICES

t = time steps $\in$ T

m = months $\in$ M

d = direct-conversion options $\in$ DCO

r = intermittent renewable options $\in$ RO

s = storage-conversion options $\in$ SCO

f = fuels $\in$ F

e = electric demand charges $\in$ EDC

n = natural gas demand charges $\in$ NGDC

o = option sets $\in$ OS (DCO, RO, and SCO)

g = generic options $\in$ GO (g represents d, r, or s depending on the option set to which it is being applied)

PARAMETERS

General Parameters

NTY = number of uniformly-sized time steps in a year (8760 if an hourly increment is chosen)

NTC = number of uniformly-sized time steps considered in the optimization (TC $\neq$ TY when a compressed data set is used to represent a full year)

RP = percentage of the consumed energy that must come from renewable sources

CE (kW) = critical electric load that must be met if the grid electricity source fails

FCf,t (\$/kWh) = cost of fuel, f, during time step, t (lower heating value [LHV])

NF = number of fuels

NDCO = number of direct conversion options

NRO = number of intermittent renewable options

NSCO = number of storage conversion options

NGO = number of generic options (NGO equals NDCO, NRO, or NSCO, depending on the option set to which it is being applied)

MonEndm = the number of the last time step in each month (e.g., the last time step in January = round (NTC*(744/8760)), the last time step in December = round (NTC*(8760/8760)), or just NTC)

i = interest rate

ELt (kWh) = electric load at each time step

HLt (kWh) = heating load at each time step (there may be multiple heating loads)

CLt (kWh) = cooling load at each time step (there may be multiple cooling loads)

ELDRm (\$/kW) = electricity demand rates (usually monthly)

ELCRt (\$/kWh) = electricity commodity consumption rate at time step, t (charged for electricity usage)

ELERt (\$/kWh) = electricity commodity export rate at time step, t (credited for electricity export)

FRf,t = fuel rate for each fuel, f, at time step, t

SEEM = source energy electricity multiplier. This value is dependent on the region's electricity production portfolio and expresses the average number of units of fossil fuel energy that were used to create one unit of electricity.

$SEMF_f$ = source energy multiplier for each fuel, f.

All O Parameters: o = DCO, RO, and SCO $\in$ O

MNo,g = maximum number of each option, g, in each option set, o. (e.g., $MN_{DCO,5}$, $MN_{RO,2}$, $MN_{SCO,3}$)

CCo,g ($) = installed capital cost for each option

MCo,g ($) = maintenance cost for each option

MFo,g (#/Year) = maintenance frequency for each option

LTo,g (Years) = expected lifetime for each option

AF o,g = annuity factor for each option

DCO and SCO only parameters: o = DCO and SCO $\in$ O

MaxCo,g = maximum capacity of each option

INo,g = input flow to the each option (e.g., $IND_{CO,5}$ = electricity, $IN_{SCO,2}$ = high-temperature hot water)

OUT1o,g = primary output flow from each option

CF1o,g (Varies) = conversion factor from the input to the first output for each option

DO only parameters: o = DCO $\in$ O

OUT2o,g = secondary output flow from each option

OUT3o,g = tertiary output flow from each option

CF2o,g (Varies) = conversion factor from the input to the second output for each option

CF3o,g (Varies) = conversion factor from the input to the third output for each option

RO only Parameters: o = RO $\in$ O

RP,r,t (kWh) = intermittent renewable energy output at each time step for each intermittent renewable option

SCO only Parameters: o = SCO $\in$ O

SCSCO,s (kWh) = maximum storage capacity for each storage conversion option

SBL SCO,s (kWh) = passive standby loss for each storage conversion option

VARIABLES

General Variables

$vN_{o,g}$ = quantity of each option, *g*, of option set, *o*, selected by the optimization

$vF_{f,t}$ = quantity of fuel, *f*, consumed during time step, *t*

$vELFU_t$ = quantity of electricity purchased from the utility during time step, *t*

$vELTU_t$ = quantity of electricity sold to the utility during time step, *t*

vELG = quantity of electricity generated during time step, *t*

$vELP_m$ (kW) = electricity demand peak for each month, *m*

vREU (kWh) = total renewable energy use

Economic Variables

vEAC = equivalent annual cost (includes capital costs, operations and maintenance [O&M], etc.)

vAE_C = annualized equipment capital cost

vO_C = annual operating cost

vM_C = annual maintenance and personnel costs

vEL_C = annual electricity cost

vF_C_f = annual fuel cost for fuel, *f*

vELD_C = annual electricity total demand cost

vELC_C = annual electricity commodity cost

All O Variables: o = DCO, RO, and SCO $\in$ O

$vOUT1_{o,g,t}$ = quantity of the primary output from option, g, of option set, o, during time step, t

DCO and SCO only Variables: o = DCO and SCO $\in$ O

$vONOFF_{o,g,t}$ (binary) = This binary variable indicates whether the option, g, of option set, o, is on or off during time step, *t*. It is needed to constrain the minimum output an option can provide while active.

$vIN_{o,g,t}$ = Input quantity to option, g, of option set, o, during time step, *t*

DCO only Variables: o = DCO $\in$ O

$vOUT2_{o,g,t}$ = quantity of the secondary output from option, d, of option set, DCO, during time step, *t*

$vOUT3_{o,g,t}$ = quantity of the tertiary output from option, d, of option set, DCO, during time step, *t*

SCO only Variables: o = SCO $\in$ O

$vINOUT_{SCO,s,t}$ = input quantity to storage conversion option, s, during time step, *t* (after conversion losses)

$vStor_{SCO,s,t}$ = stored quantity for storage conversion option, s, during time step, *t*

OBJECTIVE FUNCTION

The objective of this model is to minimize the equivalent annual cost (EAC) of meeting all the building cluster loads and additional imposed constraints. Equation 1 states this objective simply as the minimization of the total equivalent annual cost variable, *vEAC*. The annual equivalent capital cost, maintenance and personnel, fuel, and electricity components of the annual equivalent cost are then broken out in Equations 2–10. Equation 10 provides the annuity factor that converts the total capital cost into an equivalent annual amount that is required to pay back the debt and interest within each option's lifetime.

$$\text{Min } vEAC \tag{1}$$

Components of the Equivalent Annual Cost, *vEAC*

Equation 2 breaks the total equivalent annual cost, *vEAC*, down into the annual equivalent capital cost, *vAE_C*, and the annual operation cost, *vO_C*, components.

$$vEAC = vAE\_C + vO\_C \tag{2}$$

Equation 3 provides the definition of annual equivalent capital cost. This cost is made up of the total installed capital cost of each piece of equipment, $CC_{o,g}$, times the number of instances of each piece of equipment, $vN_{o,g}$, times the annuity factor, $AF_{o,g}$, and summed over each option, g, and over each option set, o. Note that the current form of the model assumes that there is no salvage or recovery value for the equipment at the end of its life.

$$vAE\_C = \sum_{o = DCO}^{SCO} \sum_{g = 1}^{NGO} CC_{o,g} \cdot vN_{o,g} \cdot AF_{o,g} \tag{3}$$

Equation 4 defines the annuity factor or capital recovery factor, $AF_{o,g}$. The annuity factor is dependent on the effective interest rate, *i*, and the lifetime of the option, *LTo,g*. This factor is used to determine the fraction of the total installed cost that is associated with each year of ownership.

$$AF_{o,g} = \frac{i(1+i)^{LT_{o,g}}}{(1+i)^{LT_{o,g}} - 1} \tag{4}$$

Equation 4 breaks the annual operation cost, *vO_C*, down into the equipment maintenance and operations cost, *vM_C*; annual electricity cost, *vEL_C*; and the sum of the annual fuel costs, vF_C_f.

$$vO\_C = vM\_C + vEL\_C + \sum_{f = 1}^{NF} vF\_C_f \tag{5}$$

Equation 5 provides the definition of annual maintenance and operation cost. This cost is made up of the maintenance and operation cost of each piece of equipment, $MC_{o,g}$, times the number of instances of each piece of equipment, $vN_{o,g}$, summed over each option, g, and over each option set, o.

$$vM\_C = \sum_{o = DCO}^{SCO} \sum_{g = 1}^{NGO} MC_{o,g} \cdot vN_{o,g} \tag{6}$$

Equation 6 breaks the annual electricity cost, *vEL_C*, down into the annual electricity demand cost, *vELD_C*, and the annual electricity commodity cost, *vELC_C*.

$$vEL\_C = vELD\_C + vELC\_C \tag{7}$$

Equation 7 defines the annual electricity demand cost as the electricity demand rate for each month, $ELDR_m$; times the electric peak for each month, $vELP_m$; summed over the 12-month period.

$$vELD\_C = \sum_{m = 1}^{12} ELDR_m \cdot vELP_m \tag{8}$$

Equation 8 defines the annual electricity commodity cost as the electricity taken from the utility at each time step, $vELFU_t$; times the electricity commodity rate, $ELCR_t$; minus the electricity exported from the community at each time step, $vELTU_t$; times the exported electricity commodity rate, $ELCR_t$; all summed over the number of time steps. This quantity is then scaled by a factor of the number of time steps in a year, *NTY*, divided by the number of time steps in the compressed data set, *NTC*. This scaling factor allows for proper cost accounting when using a reduced number of time steps.

$$vELC\_C = \sum_{t = 1}^{NTC} (vELFU_t \cdot ELCR_t - vELTU_t \cdot ELER_t) \cdot \frac{NTY}{NTC} \tag{9}$$

Equation 9 further breaks down the sum of the fuel cost into the fuel usage for each fuel and time step, $vF_{f,t}$, and the fuel rate for each fuel and time step, $FR_{f,t}$.

$$\sum_{f = 1}^{NF} vF\_C_f = \frac{NTY}{NTC} \sum_{f = 1}^{NF} \sum_{t = 1}^{NTC} (vF_{f,t} \cdot FR_{f,t}) \tag{10}$$

Constraints

Equation 11 is a constraint that defines each month's electricity peak, *vELPm*, as being greater than or equal to the electricity that comes from the utility, *ELFUt*, during every time step within that month. The monthly electricity peaks are needed for the calculation of the electricity demand cost as a part of the equivalent annual cost. As a brief reminder, the ∀ symbol means "for all." This means that each of these equations represents many equations. Usually this can be thought of by writing out the equation with the first value of each index, after which new equations are written by incrementing the last index through all values (farthest right), then incrementing the next index (moving left one index) one and incrementing again through all values of the last index. This process is repeated until all combinations of index values have been used.

$$\forall(m \text{ in } 1..12, \text{t in } 1 + MonEnd_{m-1}..MonEnd_m): \quad vELP_m \geq vELFU_t \tag{11}$$

Constraints that Apply to All Options

Equation 12 constrains the number of each option selected, $vN_{o,g}$, to be less than or equal to the maximum number of that particular option, $MN_{o'g}$. The maximum number of each option must be defined as a part of the model and becomes one of the option parameters that are given to the model. Most options can have many instances, but some options are limited in number (e.g., options that already exist on location are given no first cost, but the quantity must be limited to the actual number present). This constraint is required for all options (direct conversion, intermittent renewable, and storage conversion options).

$$\forall(o \text{ in } O,\ g \text{ in } GO):\ vN_{o,g} \le MN_{o,g} \tag{12}$$

Constraints that Apply to Direct and Storage Conversion Options Only

Equation 13 constrains the output, $vOUT1_{o,g,t}$, of direct and storage conversion options to be less than or equal to the option's maximum output capacity, $MaxC_{o,g}$. This maximum output capacity is defined as a part of the option's parameters. Appendix A provides the values for options considered in the example study.

$$\forall(DCO \text{ and } SCO \text{ in } O,\ g \text{ in } GO,\ t \text{ in } T):\quad vOUT1_{o,g,t} \le MaxC_{o,g} \cdot vN_{o,g} \tag{13}$$

Equations 14 and 15 tie the maximum, $MaxC_{o,g}$, and minimum, $MinC_{o,g}$, operation capacities to a binary variable that determines whether the option is on or off, $vONOFF_{o,g,t}$. These equations constrain the direct and storage conversion options to operation that is within a set range or turned off. The constraints help to minimize large errors that may arise from operation of the options far outside of the range in which the stated efficiencies are valid.

$$\forall(DCO \text{ and } SCO \text{ in } O,\ g \text{ in } GO,\ t \text{ in } T):\quad vOUT1_{o,g,t} \le MaxC_{o,g} \cdot vONOFF_{o,g,t} \tag{14}$$

$$\forall(DCO \text{ and } SCO \text{ in } O,\ g \text{ in } GO,\ t \text{ in } T):\quad vOUT1_{o,g,t} \ge MinC_{o,g} \cdot vONOFF_{o,g,t} \tag{15}$$

Constraints that Apply to Direct Conversion Options Only

Equation 16–18 constrain the direct conversion option's output, $vOUT1_{DCO,d,t}$, to equal a constant conversion factor, $CF1_{DCO,d}$, times the option's input, $vIN_{DCO,d,t}$. Most of the time, the conversion factor is equal to the conversion process efficiency (e.g., boilers, reciprocating engines) or coefficient of performance (chillers). These three equations link a singular input to three potential outputs through conversion factors. This is particularly useful for direct-conversion options that involve the cogeneration of multiple products, typically heat and electricity (e.g., gas turbine, steam turbine, ORC).

$$\forall(d \text{ in } DCO,\ t \text{ in } T):\ vOUT1_{DCO,d,\mathrm{t}} = CF1_{DCO,d} \cdot vIN_{DCO,d,\mathrm{t}} \tag{16}$$

$$\forall(d \text{ in } DCO,\ t \text{ in } T):\ vOUT2_{DCO,d,\mathrm{t}} = CF2_{DCO,d} \cdot vIN_{DCO,d,\mathrm{t}} \tag{17}$$

$$\forall(d \text{ in } DCO,\ t \text{ in } T):\ vOUT3_{DCO,d,\mathrm{t}} = CF3_{DCO,d} \cdot vIN_{DCO,d,\mathrm{t}} \tag{18}$$

Constraints that Apply to Storage Conversion Options Only

Equation 19 is analogous to Equations 16–18, but it applies to storage conversion options. This equation is treated differently than the previous three because the input and output of the storage device must be allowed to be decoupled in time. Since storage capacity is usually rated based on the output, the conversion (or loss) factor is defined to occur as the flow enters storage.

$$\forall(s \text{ in } SCO,\ t \text{ in } T):\ vINOUT_{SCO,s,\mathrm{t}} = CF1_{SCO,s} \cdot vIN_{SCO,s,\mathrm{t}} \tag{19}$$

Equation 20 defines the charge state of the storage, $vStor_{SCO,s,1}$, to be full on the first time step by stating that it is equal to the maximum capacity, $SC_{SCO,s}$, of the storage conversion option times the number of instances of that storage option, $vN_{SCO,s}$. Similarly, Equation 21 defines the charge stage of the last time step, NTC, as being full.

$$\forall(s \text{ in } SCO):\ vStor_{SCO,s,1} = SC_{SCO,s} \cdot vN_{SCO,s} \tag{20}$$

$$\forall(s \text{ in } SCO):\ vStor_{SCO,s,NTC} = SC_{SCO,s} \cdot vN_{SCO,s} \tag{21}$$

Equation 22 constrains the charge state of the storage option to be less than or equal to the maximum charge state times the number of instances of the option.

$$\forall(s \text{ in } SCO,\ t \text{ in } T):\ vStor_{SCO,s,t} \le SC_{SCO,s} \cdot vN_{SCO,s} \tag{22}$$

Equation 23 defines the charge state at all intermediate time steps. This is done by equating the incoming flow, $vINOUT_{SCO,s,t}$, plus the charge state from the previous time step, to the constant standby loss, $SBL_{SCO,s}$, times the number of instances of the option, $vN_{SCO,s}$, plus the current charge state, $vStor_{SCO,s,t}$, plus the outgoing flow, $vOUT_{SCO,s,t}$. The parameter, $SBL_{SCO,s}$, appears in Equation 23 to define a constant loss term that must be met regardless of the option's use. The standby loss and conversion loss factors associated with storage options were initially created to approximately capture the dominant thermal loss types in a thermal network. The standby loss approximates the constant energy loss to the ground and surroundings, no matter what load is being drawn. The conversion loss can be used to approximate loss of return water or condensate and any heat exchanger losses at the buildings.

$$\forall(s \text{ in } SCO,\ t \text{ in } T):\ vINOUT_{SCO,s,t} + vStor_{SCO,s,t-1} = SBL_{SCO,s} \cdot vN_{SCO,s} + vStor_{SCO,s,t} + vOUT_{SCO,s,t} \tag{23}$$

Constraints on Intermittent Renewable Outputs

Equation 24 defines each renewable option's output, $vOUT1_{RO,r,t}$, as the predetermined production from one instance of the option, $RP_{RO,r,t}$, times the number of instances of the option, $vN_{RO,r}$. The predetermined production data are based on the energy that would be expected in the specific location from the option during each time step, t.

$$\forall(r \text{ in } RO,\ t \text{ in } T):\ RP_{RO,r,t} \cdot vN_{RO,r} = vOUT1_{RO,r,t} \tag{24}$$

System-Wide Constraints

Equation 25 constrains the total renewable energy use, $vREU$, to be less than or equal to the sum of the intermittent renewable options' outputs, the biogas usage, and the biomass usage. This constraint can be used to determine the lowest solution that still provides a certain amount of energy from renewable sources.

$$vREU \leq \frac{NTY}{NTC}\sum_{t=1}^{NTC}\left[\sum_{r=1}^{RO} vOUT_{RO,r,t} + vF_{Biogas,t} + vF_{Biomass,t}\right] \tag{25}$$

Equation 26 provides an example of net-metering constraint. The form given represents a net-metering contract that limits the installation to zero net annual income. Other contracts may set limits on the quantity of energy exported or change rates when an installation becomes a net exporter. This equation is site specific as an installation's ability to participate in, and to be compensated for, net metering are dependent on their state and regional environments. All of these aspects can have a strong impact on the final solution for an installation.

$$\sum_{t=1}^{NTC} vELFU_t \cdot ELCR_t \geq \sum_{t=1}^{NTC} vELTU_t \cdot ELCR_t \tag{26}$$

Equation 27 provides one definition of a net-zero fossil fuel energy installation. In this equation, $SEMF_f$ and $SEEM$ are the source energy multipliers that multiply the energy used on site (site energy) by a factor that accounts for the energy used to get the site energy to the location and into its current form (accounting for conversion and transportation losses to capture total energy usage from the source). This definition would allow the installation to consume fossil-fuel-based energy, as long as that energy is offset by energy that the installation exports and is used to displace an equal amount of fossil-fuel-based energy. In other words, there is no additional fossil fuel usage due to the existence of the installation. This definition is one of many under consideration at this time. This equation can be changed to fit the goals of a particular analysis:

$$0 \geq \frac{NTY}{NTC}\sum_{t=1}^{NTC} \cdot \left[\sum_{f=1}^{NF} vF_{f,t} \cdot SEMF_f + (vELFU_t - vELTU_t) \cdot SEEM\right] \tag{27}$$

A few constraints remain that must be uniquely generated for each problem. These constraints are discussed without providing generalized equations for each. The first such constraint is related to the critical electricity requirement for the building cluster. The requirement must be input as a fixed minimum electric power load that must be met by the generation equipment. This input becomes a constraint that places a minimum requirement on the sum of the maximum electrical power outputs for all on-demand generation equipment chosen. The solution to the optimization problem is then required to include equipment that could meet this critical electricity load. Similar constraints can be developed for heating and cooling requirement as needed. This was needed, for example, in work performed at a facility housing a large supercomputer. Further, a redundancy constraint can be included that requires that the maximum load can still be met when the largest generation option is unavailable (n + 1 redundancy). These types of constraints must be generated using only the on-demand options, such as boilers, which are capable of contributing toward meeting a load during any given time step. Because these constraints are dependent on the output type of each option, and on whether the option is capable of on-demand energy conversion, they are difficult to express in a general equation form.

The most important constraints that must be generated for each cluster are the energy and matter flows. These equations define the interactions between energy and matter carriers and the various options that can be selected. For example, the constraint on natural gas flow has the variable for natural gas use at each time step, $vF_{Nat\ Gas,t}$, on one side of the equation and the input variables ($vIN_{o,g,t}$) for all the options that can have natural gas as their input on the other side. The constraint is repeated for all time steps considered in the optimization, NTC. All flows are treated in this manner, where the source of the flow must be equal to the consumption of the flow at each time step, t. Two example equations for direct conversion-only options are provided in Equations 28 and 29. Equation 28 equates the natural gas consumption during a given time step with the sum of the input energy for all options that run on natural gas. (The option numbers of 4, 8, 15, 16, 23, and 42 were used arbitrarily in this example.) Similarly, the outputs for all options that provide distributed hot water are equated to the heating load at each time step in Equation 29.

$$\forall(t \text{ in } T)\text{: } vF_{Nat\ Gas,t} = vIN_{DCO,4,t} + vIN_{DCO,8,t} + vIN_{DCO,15,t} + vIN_{DCO,16,t} \; vIN_{DCO,23,t} + vIN_{DCO,42,t} \tag{28}$$

$$\forall(t \text{ in } T)\text{:} vOUT1_{DCO,4,t} + vOUT1_{DCO,8,t} + vOUT1_{DCO,15,t} + vOUT1_{DCO,16,t} \; vOUT1_{DCO,23,t} + vOUT1_{DCO,42,t} = HL_t \tag{29}$$

A few initial comments on the model are now appropriate. A compressed year can be used to reduce the computation time. This can be accomplished either by sampling fewer time steps and taking the resulting year as representative, or by using longer time steps. The latter may unacceptably "smooth out" temporal effects such as diurnal storage, peak demand charges, and peak load timing. If the sampling approach is chosen, the compressed year consists of NTC time steps, where NTC is lower than the number that would typically make up a year, NTY. This reduced data set must preserve both the relative frequency of occurrence of various load magnitudes and the typical daily profile of the original data to ensure correct sizing of the selected options. The latter requirement allows storage on the diurnal time scale to be portrayed accurately. As a result of the abbreviated year, variable costs represented in the objective function must be scaled, as exemplified in Equations 8 and 9. Work is ongoing to determine if and when such methods can be used without adversely affecting the solution.

Finally, limits on equipment cycling have not been implemented in the model at this time. This may lead to unrealistic operation for some of the largest equipment and, ultimately, slightly lower costs than could normally be achieved. However, these effects appear to be minor in the data received from initial work.

EXAMPLE STUDY

Problem Statement

This installation example was performed on a building cluster composed of 46 buildings from an installation in the central plains region. All of the model's location specific inputs, including energy usage, weather data, and energy rates, are based on a specific, but nonidentified installation. Hourly heating, cooling, and electric loads for a typical year were developed through EnergyPlus simulations of the buildings using a process described thoroughly in previous publications (Ellis et al. 2012; Langner et al. 2012; Liesen et al. 2012; Deru et al. 2012). This process involved dividing the groups of buildings into categories based on building type and year built and running EnergyPlus simulations on a representative building for each category. The results of these simulations were then summed appropriately to provide usage data for the entire cluster of buildings. The resulting 8760-point heating, cooling, and electric load data sets were then reduced to 351-point data sets by selecting every 25th data point in the 8760-point data sets. The peaks from the 8760-point data sets were then used to replace the peaks of the 351-point data set. This method provides a much smaller data set while maintaining the demand peaks, total energy, and the approximate shape of the load duration curves. The latter are shown in Figure 3. Additionally, the diurnal cycle is maintained because each subsequent hour in the 351-point data set occurs 1 day and 1 hour later in time. The method allowed for very fast computation times and has provided very similar optimization results when compared to solutions using with 8760-point data sets. However, rigorous comparison with complete years has not been performed, nor has this method been compared against other potential methods.

The building cluster chosen for analysis was composed of a variety of buildings that were connected to a central heating and cooling plant at the time of their construction. The central plant is still in operation and has two boilers and two chillers, but no electricity generation equipment. Figure 3 sums up the heating, cooling, and electricity loads as load duration curves.

This study was performed with a natural gas rate of \$0.03/kWh (\$8.80/MMBtu), an electricity demand charge of \$5/kW-peak, an electricity energy charge of \$0.08/kWh, and an interest rate of 3%.

The purpose of the example study was to demonstrate the model's ability to find the lowest EAC architecture with a special emphasis on the importance of the redundancy constraint, on the decision to centralize or decentralize supply options, and on the determination of the lowest cost net-zero fossil fuel solution. To this end, the following alternatives were defined:

1. Baseline
2. Lowest equivalent annual cost (LEAC)
3. Lowest equivalent annual cost with heating and cooling redundancy (LEACR)
4. Decentralized boilers and chillers (DBC)
5. Net-zero fossil fuel energy (NZFFE)

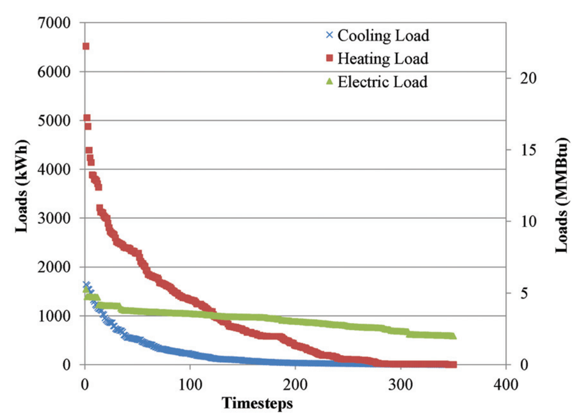

Figure 3 *Heating, cooling, and electric load duration curves for the building cluster.*

The baseline alternative provides only the current equipment to the superstructure, but still allows the operation of the equipment to be optimized. This alternative should provide a reasonable estimate for the system's current performance. The current equipment is treated like all other equipment choices, except that it has no installation costs and the maintenance and operation costs are taken (when possible) directly from the installation's data.

The lowest equivalent annual cost (LEAC) alternative opens up the superstructure to the entire equipment list, including the current equipment, and does not require redundant heating and cooling capacity. The LEACR alternative maintains the installation's stated redundancy requirements, but imposes no additional environmental constraints. This alternative is meant to provide the approximate cost of $n + 1$ redundancy. The DBC alternative defines a decentralized solution or system architecture and uses the model to compute the associated costs and energy usages. The natural gas price is increased by two cents per kilowatt-hour in this alternative to account for the addition of a distributed natural gas pipeline to all of the individual buildings. This additional charge is in line with authors' experiences at other military installations with mixed centralized and decentralized strategies. The net-zero fossil fuel energy alternative forces the model to reach net-zero fossil fuel energy status, as described in the modeling approach section and in Equation 27, for the building cluster considered. As with all alternatives, net metering can be used to meet the requirements. It is important to note that net metering is significantly less complicated when it happens "inside the fence" between a cluster targeting net zero and the remaining installation. In this case, the excess electrical production is used by other consumers within the installation and the installation as a whole never becomes a net exporter, as exporting electricity is not allowed in all locations.

Input data for the five alternatives were taken from installation-specific sources, as well as national sources. Site-specific TMY3 data were used for the EnergyPlus building simulations and to produce expected power output data for a 5 MW wind turbine. EnergyPlus was also used to provide the calculated irradiance that would be incident on a fixed-tilt panel at the location's latitude. These irradiance data are used to make up $RP_{r,t}$ for each r in RO. Natural gas and electricity rates and demand charges were taken from installation data, but biomass and biogas values were not available and national averages were used instead.

The options considered in the optimization runs include the following: existing boilers, existing air-cooled chillers, natural gas reciprocating engines with and without heat recovery, natural gas turbines with and without heat recovery, electrically-driven air-cooled chillers, electrically-driven water-cooled magnetic levitation chillers, single stage absorption chillers, two stage absorption chillers, organic Rankine cycle turbines (high and low temperature), wind turbines, solar thermal systems, photovoltaic systems, biomass central heating plant (CHP), heat-only biomass, hot water and chilled water storage, ice storage, existing hot water and cold water networks, decentralized boilers for all buildings, and decentralized chillers for all buildings. The parameters used in the equipment models are given in Appendix A and were collected from several sources including: (1) site visits to determine condition, efficiency, and maintenance costs of current infrastructure, (2) National Renewable Energy Laboratory (NREL) report for biomass and solar equipment data (NREL 2012), (3) cost estimates for proposed work using RS Means, and (4) contractor-produced installation and operation quotes.

The open-source GNU Linear Programming Kit (GLPK) was used to formulate and solve the optimization model. The model was written in GNU Mathematical Programming Language (GMPL) enabling the use of a number of solvers during the model's development. GLPSOL, a MILP solver from the GLPK, was used to solve the problems.

Results

Table 1 and Table 2 summarize the results from the five alternatives. As expected, the least-constrained alternative attained the lowest EAC.

The baseline alternative results show the cost and usage that would be expected when the current equipment is used with an optimal dispatch schedule. The results show that it is one of the lowest-cost alternatives, but has the highest fossil fuel use of any of the alternatives. The comparatively high source fossil fuel use is primarily due to the use of grid electricity. The grid electricity comes primarily from fossil fuel sources and has a source multiplier of about 3.4 at this location.

The second alternative provides the lowest EAC for the building cluster when all options are considered and redundancy in the heating and cooling systems is not required. This alternative was included to demonstrate the importance of the redundancy constraint and provide a potential lowest cost solution. The solution could be reasonable if the installation had a few building clusters and purchased one or more mobile backup boilers and chillers for use during breakdowns or maintenance. The cost for these mobile units could then be shared among multiple clusters, instead of requiring the redundancy at each location. The results for the LEAC alternative show that one existing boiler and one existing chiller were decommissioned to avoid maintenance and operation costs. The required heating was provided by the waste heat from a new natural-gas-fed reciprocating engine. This engine was run at near full capacity for most of the year and was able to meet most of the electrical needs for the building cluster. A single stage absorption chiller was also purchased and used during the summer to make use of the engine's waste heat stream. Lastly, a significant amount of hot and chilled water storage was selected in this alternative to meet the heating and cooling peaks. It should be pointed out that the model dispatches storage options with perfect knowledge of the future loads, and therefore makes the storage option seem somewhat more valuable than it would be in reality.

Table 1. Summarized Results for the Five Alternatives

	Baseline	LEAC	LEACR	DBC	NZFFE
Total Investment Cost, $	0	2,530,000	1,960,000	4,530,000	11,280,000
On-Demand Capacity:					
Heating, kW (MMBtu/hr)	14,000 (47.7)	9000 (30.7)	16,000 (54.6)	NA	16,700 (56.9)
Cooling, kW (MMBtu/hr)	6680 (22.8)	880 (3.0)	7030 (24.0)	NA	7560 (25.8)
Electricity, kW	0	1000	1000	0	800
Hot Water Storage, gal (L)	20,000 (75,600)	80,000 (302,400)	20,000 (75,600)	0	260,000 (982,800)
Chilled Water Storage, gal (L)	20,000 (75,600)	70,000 (264,600)	20,000 (75,600)	0	20,000 (75,600)
Net Electricity Purchase, kWh	8,920,000	520,000	1,460,000	8,860,000	0
Electricity Generation, kWh	0	7,710,000	6,960,000	0	8,460,000
Natural Gas Use, kWh (MMBtu)	10,430,000 (35,600)	24,580,000 (83,800)	22,570,000 (77,000)	9,680,000 (33,000)	0
Biomass Use, kWh (MMBtu)	0	0	0	0	22,930,000 (78,200)
Site Fossil Fuel-based Energy Use, kWh (MMBtu)	19,350,000 (66,000)	25,100,000 (85,600)	24,030,000 (81,900)	18,540,000 (63,200)	0
Source Fossil Fuel-based Energy Use, kWh (MMBtu)	40,760,000 (139,000)	26,350,000 (89,800)	27,530,000 (93,900)	39,800,000 (135,700)	0
Renewable Percentage, %	0	0	0	0	100
Equivalent Annual Cost, $	1,870,000	1,620,000	1,810,000	1,930,000	2,290,000

The third alternative provides the lowest EAC for the building cluster when all options are considered and redundancy in the heating and cooling systems is required. This is the most likely scenario for a realistic, budget-constrained installation. The options selected for this alternative are very similar to the LEAC alternative, except that all the existing equipment is maintained. This existing redundant capacity alleviates the need for hot- and cold-water storage to meet the peaks and reduces the optimal size of the absorption chiller. The EAC is only slightly lower than that of the baseline, despite the $2 million investment. However, the investment does have a return that is in line with the ~3% interest rate provided to the model and allows an approximately one-third reduction in source fossil fuel usage.

The fourth alternative forces the selection of decentralized boilers and chillers for all the buildings in the clusters. This alternative has the lowest site fossil fuel use of the first four alternatives, but the highest source fossil fuel use due to the lack of on-site electricity generation that allows on-site heat recovery and a lower resulting source fossil fuel use. The solution is technically simple and close to the EAC of the first four solutions, but limits the number of renewable technologies that could be added to reduce fossil fuel use in the future.

The final alternative limits the building cluster to net-zero fossil fuel use. Biomass combustion options are the backbone of this solution along with a relatively small photovoltaic system. The options are used to meet the entire heating load and part of the cooling and electric loads. The hot water output capacity from the two biomass components sum to about half of the peak heating load. The remaining load is provided by charging and discharging the 240,000-gal (907,200 L) hot water storage system. During the summer, extra waste heat from the biomass CHP unit is used to drive a 250-ton (880 kW) chiller. This chiller is used with the existing electric chillers to meet the chilled water load. Electricity is exported from the biomass power plant and the photovoltaic system to offset imported, fossil-intensive

Table 2. Summary of Selected Options for the Five Alternatives

	Baseline	LEAC	LEACR	DBC	NZFFE
Existing Boilers, 24000 lb/hr (7000 kW/23.9 MMBtu/hr)	2	1	2		2
Biomass Heat-Only, 3800 lb/hr (1100 kW / 3.75 MMBtu/hr)					1
Biomass CHP, 800 kWe					1
Natural Gas Reciprocating Engine w/ Heat Recovery, 1000kWe		1	1		
Existing Air-Cooled Chillers, 950 ton/3340 kW (11.4 MMBtu/hr)	2		2		2
Single Stage Absorption Chiller, 100 ton/350 kW (1.2 MMBtu/hr)			1		
Single Stage Absorption Chiller, 250 ton/880 kW (3 MMBtu/hr)		1			1
Photovoltaic System, 1400 kW-peak					1
Decentralized Boilers for All Buildings				1	
Decentralized Chillers for All Buildings				1	
Hot Water Storage, 60000 gal (226,800 L)		1			4
Cold Water Storage, 50000 gal (189,000 L)		1			
Existing Hot Water Distribution Network	1	1	1		1
Existing Cold Water Distribution Network	1	1	1		1

electricity. Finally, the existing boilers were maintained to meet the redundancy constraint. At about $2.29 million per year, this alternative represents an approximately 22.5% increase in the EAC over the baseline. However, a significant amount of the EAC is related to having huge, unused standby capacity. An additional NZFFE optimization run was performed without the redundancy requirement and provided a solution with an EAC of $1.89 million per year, leading to an approximately $400,000 per year cost for heating and cooling redundancy in this scenario. Again, the scenario's lack of redundancy may be acceptable for some building clusters if backup capacity could be shared by a number of clusters.

DISCUSSION

A few general observations stand out from the five alternatives. First, the baseline alternative is close to the lowest EAC alternative, and at least some of the existing equipment is used in all of the centralized solutions. This result shows the importance of the existing equipment in the final lowest EAC solution. It is interesting that the NZFFE solution made use of the existing equipment solely to satisfy the redundancy constraint, even though additional biomass capacity could have reduced the need for hot water storage. This occurred even though the existing equipment was penalized with the entire O&M costs (not including fuel) that it would have incurred if it were fully used throughout the year. This O&M cost is significantly overstated for the existing pieces if they are only used for backup and should be corrected to scale with usage for future versions of the model.

Second, the EAC for the first four solutions are relatively close in cost, but vary significantly in their architectures and fossil fuel use. The DBC solution has the lowest fossil-fuel-based site energy use due largely to the elimination of the hot and cold water networks. However, the lack of on-site electricity generation with heat recovery pushes the fossil fuel-based source energy of the DBC and baseline solutions about 50% higher than the two fossil fuel based solutions that include electricity generation.

Since the EAC values for these first four solutions are reasonably close, the tie-breaker may go to the solution that provides the greatest degree of simplicity, flexibility, or amenability towards reaching a future goal. Many factors such as fuel and electricity rates, potential carbon taxes, upcoming requirements, regional grid electricity makeup, or climate change could have an effect on the final decision. A sensitivity analysis using variations in these and other relevant parameters would be needed to determine the robustness of a solution for an actual building cluster.

Any building cluster or installation master plan would include a variety of building-scale energy efficiency measures (EEMs) in addition to supply and distribution work. These EEMs would significantly reduce the energy usage for the cluster and therefore reduce the generation capacity required to support the building loads. Determining the EEMs that are selected for each building type is currently performed as a pre-process to the community-scale supply and distribution optimization. A manual feedback process is sometimes employed between the two models before arriving at a final solution. This feedback process allows the selection of EEMs that may not be cost effective on their own, as long as they are the most cost-effective way to meet an energy security or environmental goal.

Significant effort was given to providing a robust list of community-scale energy supply options and options commonly chosen for lowest cost energy supply were well represented, but some possible NZFFE options were missing. Notably, ground source heat pump systems driven by renewably obtained electricity may be a more cost effective solution than the current NZFFE solution. When coupled with hot and cold water storage, this system would also provide enormous demand response opportunities as the heat pump could be modulated to store thermal energy during periods of high renewable electricity generation. Such a system could take advantage of the thermal capacity present in the potable water system and even the sewage system and water treatment plant. Studies of on this type of system are present in the literature (Qian 2010, 2011; Tassou 1988), but determining the installation, maintenance, and operation costs is difficult due to the limited number of systems in existence.

Finally, the presented example is not meant to be used to generally validate one technology over another, but, rather, to demonstrate the model's ability to select an optimal solution from the presented options, given varying data and constraints. All solutions will be specific to the building cluster's climate, economic environment, utility rates and structure, building composition, and other factors.

Future work will focus on the application and testing of this tool on a number of military installations. The results and feedback will drive future changes; however, a few early limitations will receive immediate attention. These include:

1. Compression of 8760-point (1 year) data files as described in the problem statement section. Computation time limits the resolution in all areas. Reducing the number of data points would allow additions to the model in other areas. Work must be done to find the proper balance so that the overall accuracy of the model is maximized for the computation time.
2. Testing should be done to determine if limiting the equipment cycling leads to a significant change in the equipment selected, or in the final cost and environmental parameters. Limitations to equipment cycling could be imposed and would increase the physicality of the model, but may lead to a dramatic increase in the computation time. Research is needed to determine if this trade-off is needed.
3. Addition of usage-scaled O&M costs. This would allow the total O&M costs to be broken down into fixed and variable components. The change would significantly lower the costs associated with standby or backup equipment.
4. Incorporation of water and waste. Military installations are facing increased legislative requirements on the conservation of water and waste. It is well known that there are many interconnections between the energy, water, and waste areas, but their extent is not well known. The incorporation of water use, and, potentially, waste generation could assist the installations in determining the lowest-cost set of options that will allow them to meet all of their current and future requirements.
5. Multiyear implementation. The optimization currently determines the lowest EAC options and operation schedule that should be chosen if all the resources were available immediately. However, for our installations, all of the financial resources are not available immediately. The optimization would be of greater use if it could account for a phased approach of implementation.

CONCLUSIONS

A MILP model has been developed to optimize the selection and operation of heating, cooling, and electric generation equipment at the building-cluster scale. This model was applied to a cluster of 46 buildings and the results of five alternative scenarios were discussed. The model suggested the addition of a natural-gas-fed reciprocating engine and small absorption chiller as a part of the lowest EAC scenario. Additionally, the model suggested a biomass and photovoltaic hybrid system with significant hot-water storage when constrained to zero fossil fuel energy. Subsequent testing and evaluation will take place on additional military installations as a part of an Environmental Technology Demonstration and Validation Program (ESTCP) project titled "Demonstrate Energy Component of the Installation Master Plan Using Net Zero Installation Virtual Testbed."

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APPENDIX A

Tables A1 to A3 provide the parameters for DCOs, SCOs, and ROs considered as a part of the superstructure. An additional O&M cost of ~$0.02/kWh of biomass consumed was added to the biomass rate to account for the operation-dependent costs given in the NREL report (NREL 2012). LTHW and HTHW refer to low temperature hot water and high temperature hot water, respectively.

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Table A1. Direct Conversion Option Parameters

Direct Conversion Options	Input Type	Output 1	Output 2	CF1	CF2	Installation Cost, $	Maintain Cost, $/yr	Lifetime, yr
Existing boiler (×2), 6950 kW (23.7 MMBtu/hr)	Natural Gas	LTHW		0.85		0	180,000	40
Natural Gas Reciprocating Engine, 300 kWe	Natural Gas	Electricity to Bus		0.31		289,230	36,977	20
Natural Gas Reciprocating Engine, 1000 kWe	Natural Gas	Electricity to Bus		0.34		878,673	87,867	20
Natural Gas Reciprocating Engine, 3000 kWe	Natural Gas	Electricity to Bus		0.35		2,599,408	248,591	20
Natural Gas Reciprocating Engine, 5000 kWe	Natural Gas	Electricity to Bus		0.37		4,240,818	392,352	20
Natural Gas Reciprocating Engine, with heat recovery, 100 kWe	Natural Gas	Electricity to Bus	LTHW	0.284	0.51	239,359	19,084	20
Natural Gas Reciprocating Engine, with heat recovery, 500 kWe	Natural Gas	Electricity to Bus	LTHW	0.346	0.44	1,050,578	69,425	20
Natural Gas Reciprocating Engine, with heat recovery, 1000 kWe	Natural Gas	Electricity to Bus	LTHW	0.35	0.44	1,776,236	110,690	20
Natural Gas Reciprocating Engine, with heat recovery, 3000 kWe	Natural Gas	Electricity to Bus	LTHW	0.36	0.37	3,671,609	270,334	20
Natural Gas Reciprocating Engine, with heat recovery, 5000 kWe	Natural Gas	Electricity to Bus	LTHW	0.39	0.35	6119348	404,527	20
Natural Gas Turbine, 1135 kWe	Natural Gas	Electricity to Bus		0.211		4,903,760	72,318	31
Natural Gas Turbine, 5338 kWe	Natural Gas	Electricity to Bus		0.273		10,663,045	235,401	31
Natural Gas Turbine, 9983 kWe	Natural Gas	Electricity to Bus		0.279		17,866,872	426,209	31
Natural Gas Turbine, 22708 kWe	Natural Gas	Electricity to Bus		0.336		31,484,614	678,409	31
Natural Gas Turbine, 45331 kWe	Natural Gas	Electricity to Bus		0.361		53,992,053	1,141,419	31
Natural Gas Turbine, with heat recovery, 1135 kWe	Natural Gas	Electricity to Bus	HTHW	0.211	0.453	6,412,579	103,312	31
Natural Gas Turbine, with heat recovery, 5338 kWe	Natural Gas	Electricity to Bus	HTHW	0.273	0.423	12,756,620	336,287	31
Natural Gas Turbine, with heat recovery, 9983 kWe	Natural Gas	Electricity to Bus	HTHW	0.279	0.402	21,245,185	608,870	31
Natural Gas Turbine, with heat recovery, 22708 kWe	Natural Gas	Electricity to Bus	HTHW	0.336	0.392	37,270,160	969,156	31
Natural Gas Turbine, with heat recovery, 45331 kWe	Natural Gas	Electricity to Bus	HTHW	0.361	0.302	63,335,594	1,630,598	31
Natural Gas Boiler, 1000 kW (3.4 MMBtu/hr)	Natural Gas	LTHW		0.84		812,500	24,375	40

Table A1. *(continued)* Direct Conversion Option Parameters

Direct Conversion Options	Input Type	Output 1	Output 2	CF1	CF2	Installation Cost, $	Maintain Cost, $/yr	Lifetime, yr
Natural Gas Boiler, 2500 kW (8.5 MMBtu/hr)	Natural Gas	LTHW		0.86		2,031,250	60,937	40
Natural Gas Boiler, 10000 kW (34 MMBtu/hr)	Natural Gas	LTHW		0.87		8,125,000	243,750	40
Existing Electric Chillers (x2), 3340 kW (11.38 MMBtu/hr)	Electricity from Bus	Chilled Water		2.96		0	20,000	20
Electric Chiller, Air-cooled, 352 kW (1.2 MMBtu/hr)	Electricity from Bus	Chilled Water		2.96		89,896	2697	20
Electric Chiller, Air-cooled, 879 kW (3.0 MMBtu/hr)	Electricity from Bus	Chilled Water		2.96		150,335	4510	20
Electric Chiller, Air-cooled, 1055 kW (3.6 MMBtu/hr)	Electricity from Bus	Chilled Water		2.96		205,187	6156	20
Electric Chiller, Air-cooled, 1758 kW (6.0 MMBtu/hr)	Electricity from Bus	Chilled Water		2.96		338,935	10,168	20
Electric Chiller, Magnetic Levitation water-cooled, 527 kW (1.8 MMBtu/hr)	Electricity from Bus	Chilled Water		7.92		326,718	3267	20
Electric Chiller, Magnetic Levitation water-cooled, 1019 kW (3.5 MMBtu/hr)	Electricity from Bus	Chilled Water		8.49		631,655	6316	20
Electric Chiller, Magnetic Levitation water-cooled, 1371 kW (4.7 MMBtu/hr)	Electricity from Bus	Chilled Water		8.45		849,467	8494	20
Electric Chiller, Magnetic Levitation water-cooled, 2004 kW (6.8 MMBtu/hr)	Electricity from Bus	Chilled Water		8.35		1,241,529	12,415	20
Electric Chiller, Magnetic Levitation water-cooled, 2461 kW (8.4 MMBtu/hr)	Electricity from Bus	Chilled Water		8.35		1,524,684	15,246	20
Absorption Chiller, Single-Stage, 352 kW (1.2 MMBtu/hr)	LTHW	Chilled Water		0.7		184,653	9233	20
Absorption Chiller, Single-Stage, 879 kW (3.0 MMBtu/hr)	LTHW	Chilled Water		0.7		359,748	17,987	20
Absorption Chiller, Single-Stage, 2339 kW (8.0 MMBtu/hr)	LTHW	Chilled Water		0.7		712,120	35,606	20
Absorption Chiller, Single-Stage, 3359 kW (11.5 MMBtu/hr)	LTHW	Chilled Water		0.7		948,171	47,409	20
Absorption Chiller, Single-Stage, 5152 kW (17.6 MMBtu/hr)	LTHW	Chilled Water		0.7		1,410,910	70,545	20
Absorption Chiller, Dual-Stage, 352 kW (1.2 MMBtu/hr)	HTHW	Chilled Water		1.1		298,842	14,942	20
Absorption Chiller, Dual-Stage, 879 kW (3.0 MMBtu/hr)	HTHW	Chilled Water		1.1		578,897	28,945	20
Absorption Chiller, Dual-Stage, 2339 kW (8.0 MMBtu/hr)	HTHW	Chilled Water		1.1		1,125,138	56,257	20
Absorption Chiller, Dual-Stage, 3359 kW (11.5 MMBtu/hr)	HTHW	Chilled Water		1.1		1,498,124	74,906	20

Table A1. *(continued)* Direct Conversion Option Parameters

Direct Conversion Options	Input Type	Output 1	Output 2	CF1	CF2	Installation Cost, $	Maintain Cost, $/yr	Lifetime, yr
Absorption Chiller, Dual-Stage, 5152 kW (17.6 MMBtu/hr)	HTHW	Chilled Water		1.1		2,215,611	110,781	20
Organic Rankine Cycle, High Temperature, 1000 kWe	HTHW	Elec. to Bus		0.19		4,290,000	195,000	20
Organic Rankine Cycle, High Temperature, 1400 kWe	HTHW	Elec. to Bus		0.19		4,862,000	221,000	20
Organic Rankine Cycle, Low Temperature, 1400 kWe	LTHW	Elec. to Bus		0.09		616,000	28,000	20
Electrical Bus, 10000 kWe	Electricity to Bus	Elec. from Bus		0.98		0	0	50
Heat Exchanger	HTHW	LTHW		0.98		0	0	30
Biomass Boiler, 100 kW (0.34 MMBtu/hr)	Biomass	LTHW		0.82		100,000	4300	30
Biomass Boiler, 1000 kW (3.4 MMBtu/hr)	Biomass	LTHW		0.82		1,000,000	43,000	30
Biomass Boiler with CHP, 100 kWe	Biomass	Elec. to Bus	LTHW	0.30	0.45	552,800	4100	30
Biomass Boiler with CHP, 1000 kWe	Biomass	Elec. to Bus	LTHW	0.30	0.45	5,528,000	41,000	30
Distributed Boilers, 46 Boilers Individually Sized	Retail Natural Gas	Distrib. Hot Water		0.85		2,396,439	163,575	20
Distributed Chillers, 46 Chillers Individually Sized	Electricity from Bus	Distrib. Chilled Water		2.96		2,136,751	154,638	18

Table A2. Renewable Options Parameters

Intermittent Renewable Options	Output	Install. Cost, $	Maint. Cost, $/Year	Lifetime, Years
Photovoltaic System, 14 kWe peak	Elec. To Bus	620,000	360	32
Photovoltaic System, 140 kWe peak	Elec. To Bus	513,900	3360	32
Photovoltaic System, 1400 kWe peak	Elec. To Bus	4,736,000	31,000	32
Solar Thermal System, 100 m^2 (1076 ft^2)	LTHW	146,600	1460	32
Solar Thermal System, 1000 m^2 (10,760 ft^2)	LTHW	1,466,000	14,600	32
Wind Turbine, 2.5 MWe peak	Elec. To Bus	5,000,000	50,000	30

Table A3. Storage Conversion Option Parameters

Storage Conversion Options	Input Type	Output 1	CF1	Installation Cost, $	Maintenance Cost, $/Year	Storage Capacity, kWh (MMBtu)	Standby Loss, kW (MMBtu/hr)	Lifetime, yr
Chilled Water Storage, 925 kW (3.15 MMBtu/hr)	Chilled Water	Chilled Water	0.98	67,196	500	925 / 3.15	1 / 0.003	40
Chilled Water Storage, 3085 kW (10.5 MMBtu/hr)	Chilled Water	Chilled Water	0.98	184,042	1,000	3,085 / 10.5	1 / 0.003	40
Chilled Water Storage, 3702 kW (12.6 MMBtu/hr)	Chilled Water	Chilled Water	0.98	209,690	1,000	3,702 / 12.6	1 / 0.003	40
Hot Water Storage, 1202 kW (4.1 MMBtu/hr)	LTHW	LTHW	0.98	67,196	500	1,202 / 4.1	1 / 0.003	40
Hot Water Storage, 4010 kW (13.7 MMBtu/hr)	LTHW	LTHW	0.98	184,042	1,000	4,010 / 13.7	3 / 0.010	40
Hot Water Storage, 4813 kW (16.4 MMBtu/hr)	LTHW	LTHW	0.98	209,690	1,000	4,813 / 16.4	4 / 0.014	40
Hot-Water Distribution Network	LTHW	Distribution Hot Water	0.98	0	200,000	1,200 / 4.1	55 / 0.190	25
Chilled-Water Distribution Network	Chilled Water	Distribution Chilled Water	0.92	0	140,000	950 / 3.2	5 / 0.017	25

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DISCUSSION

David Baylon, President, Ecotope, Inc, Seattle, WA: Did you use discount rates to present value energy cost, capital cost? If so, what rates?

PV calculation seems appropriate although it assumes no changes in future fuel costs or value. Were capital discount rates deemed so we avoided that question?

Matthew Swanson: The capital recovery factor method was used to annualize the cost of equipment. This formula takes the interest rate and equipment lifetime into account when calculating the annual cost of ownership. This method allows us to specify a specific interest rate for each potential piece of equipment depending on the type of financing (government or commercial).

We are currently using existing fuel prices without any type of forecasting (escalation, etc.). However, we often perform a fuel-based sensitivity analysis by varying the energy prices and looking for any changes to the equipment that is selected. This type of analysis can be done using fuel prices, weather, and even the number of buildings included in the study to ensure the solution is robust.

Dominick Chirico, Director of Engineering, Columbia University Facilities, New York, NY: 1) How many integer variables are there? 2) Which algorithms for integer solution were used?

Matthew Swanson: 1) We are using one integer variable for every piece of equipment or option that is considered by the optimization. We currently have models for about 20 different technologies and each technology has about 5 sizes to capture economies of scale (~100 total integer variables). 2) The mixed integer linear program problem is written so that it can be interpreted by open source Generic Mathematical Programming Language (GMPL) or proprietary A Mathematical Programming Language (AMPL). This formulation allows the problem to be solved by a number of different mixed integer linear programming solvers. We are currently using open source Generic Linear Programming solver (GLPSol) and proprietary CPLEX. This parallel formulation provides benefits of computation speed and ease of distribution depending on the current needs. It also aligns with the overall Net Zero Planner goals to provide a computational framework to solve the greater community planning problem while allowing the user to swap analogous software components throughout the tool.