Chapter 10
Economics of Energy Master Plan Implementation

Abstract An Energy Master Planning (EMP) is not limited to energy-related projects; it may include a spectrum of non-energy-related projects, including new building construction and demolition, utility modernization projects, and non-energy-related measures to enhance the resilience of energy systems, such as the elevation of energy equipment, construction of floodwalls, burying of cables. In most cases, an EMP covers multiple interrelated projects where the outcome of one project or a group of projects influences one or more other projects (e.g., building efficiency improvements impact the size of required energy generation capacity; thermal energy supply to a new building requires installation of a pipe connection to existing district system; connection of additional buildings to a hot water district system allows for an increase of CHP baseload). Therefore, the selection of alternatives for an EMP shall be based on the cost-effectiveness of the entire EMP instead of individual projects that comprise the EMP. It is possible that some individual projects will not be cost-effective when considered separately. This chapter discusses the development of the business case, different costs throughout the project life cycle that the Energy Master Plan must consider, and business and financial models that can be used for implementation.

10.1 Introduction

Chapter 3 discussed methodologies for selecting alternatives that will meet minimum energy requirements and that will, to the greatest extent possible, reach the desired goals and cost-effectiveness. Chapter 2 discussed a multicriteria analysis of alternatives and scenario selection that allow the integration of economic, energy, and resilience targets to address decision-makers' priorities that go beyond economics. When an alternative is selected, it must be implemented. Chapter 10 discusses the development of the business case, different costs throughout the project life cycle that the energy master plan (EMP) must consider, and business and financial models that can be used for implementation.

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10.2 EMP Scope and Life-Cycle Cost

The cost and implementation strategies of the energy master plan depend on its scope, timeline, and complexity.

10.2.1 Scope

The scope of the EMP can be broad and may include new construction, demolition, and consolidation projects; energy supply; and energy distribution and energy storage components, including creative methods to build innovative site-to-grid arrangements that may provide grid stability or site resilience. An EMP is not limited to energy-related projects; it may include a spectrum of non-energy-related projects, including new building construction and demolition, and utility modernization projects and non-energy-related measures to enhance the resilience of energy systems to design-based threats, such as the elevation of energy equipment, construction of flood walls, and burying of cables (Fig. 10.1).

In most of cases, an EMP covers multiple interrelated projects (see Fig. 10.2) where the outcome of one project or a group of projects influences one or more other projects (e.g., where building efficiency improvements impact the size of required energy generation capacity, thermal energy supply to a new building requires installation of a pipe connection to existing district system, or connection of additional buildings to a hot-water district system allows for an increase of CHP base load). Therefore, *selection of alternatives for an EMP shall be based on cost-effectiveness of the entire EMP instead of individual projects* that comprise the EMP. It is possible that some individual projects will not be cost-effective when considered separately.

Fig. 10.1 Scope of work under EMP

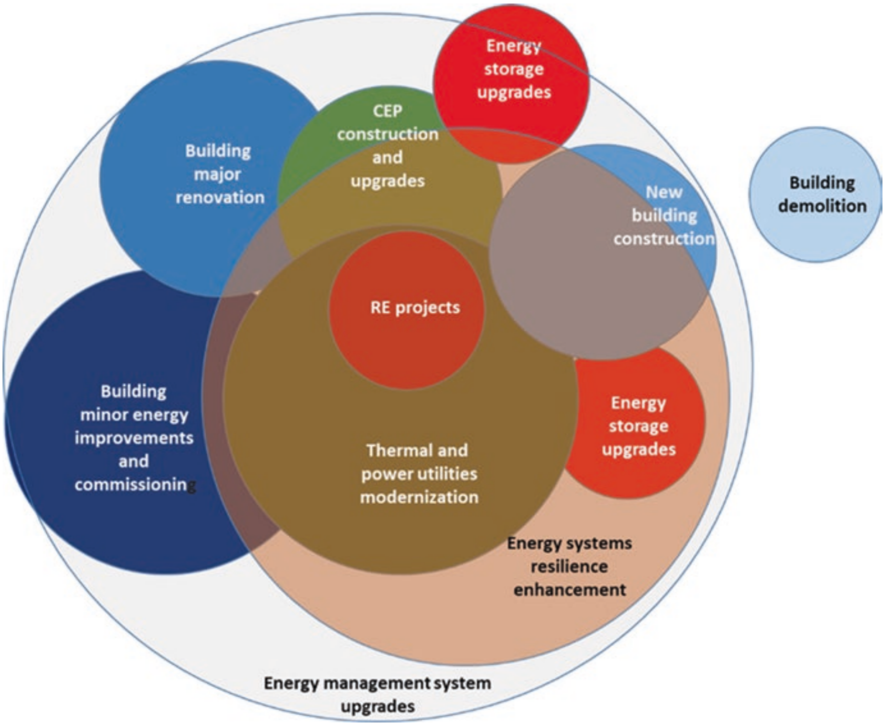

Fig. 10.2 Interrelation of projects under EMP

10.2.2 Life-Cycle Cost Analysis

LCCs typically include the following two cost categories: investment-related costs and capital expenditures (CAPEX), and operating expenditures (OPEX).

Investment-related costs include costs related to planning, design, purchase, construction, and replacement. The selection of the data sources for investments greatly impacts the reliability of an LCCA. For an LCCA to be plausible, three main data sources must be considered and merged:

- Manufacturer, supplier, and/or contractor data
- Empirical data (e.g., case studies)
- Data from building modeling databases

Investment costs describe the total expenses of the investment into (1) buildings and (2) energy supply and distribution systems. These costs include the planning, modeling, design, and implementation of new materials and the replacement and disposal costs of replaced materials, including both material and labor costs. The number and timing of **capital replacements or future investments** depend on the estimated life of a system and length of the service period. Sources for cost estimates for initial investments can be used to obtain estimates of replacement costs and expected service lives. A good starting point for estimating future replacement costs is to use initial investment costs along with price escalation factors related to comparable building construction and energy supply investment cost indices.

Synergetic Impacts The determination of the investment costs must consider synergetic impacts that can be obtained from a holistic EMP approach. For example, one approach could be to combine demand reduction on building and energy supply level measures, which would in turn allow supply to be reduced as a result of the reduction in demand on the building level. Another approach could be to organize piping and cable configurations for thermal and electrical grids located in infrastructure trenches to reduce trenching costs, which, depending on underground conditions, can comprise over 50% of the total grid costs.

Grants Grants, rebates, and other one-time payment financial subsidies for energy-efficient and sustainable design reduce the initial investment costs and are used to create a political climate that creates sufficient incentives to promote energy demand, supply, and distribution structures on the regional and local level. In European countries, major grant programs provide grants for partial or holistic renovations based on a percentage of the incremental investment costs compared to the national minimum requirements. Rates vary from country to country ranging from 20% to 50% of the incremental initial investments. The political framework in the EU has created incentives for centralized systems because these systems accommodate fuel and technology transitions more easily than do detached systems, which can involve more complex, multiple-party decision-making processes. Also, the setup of local, smaller district heating grids is a necessary prerequisite to the creation of a high-efficiency energy system that can use waste heat, such as that produced by medium-sized heating plant (HP) systems, to generate electricity. As power grids prioritize renewable power production, the setup of a new parallel grid structure on the local and regional level has become necessary to provide sufficient grid capacities. Many EU countries promote thermal and electrical microgrids by providing subsidies to set up or refurbish existing grids. These subsidies aim to reduce the incremental costs of connecting grids and detached individual supply solutions in areas with middle or low energy demand density, with a prioritization of centralized systems.

The **residual value** of a system (or component) is its remaining value at the end of the study period. The study period for an LCCA is the time over which the costs and benefits related to a capital investment decision are of interest to the investor. Residual values can be based on value in place, resale value, salvage value, or scrap value or on the net value of any selling, conversion, or disposal costs. The "economic life" of a system refers to the time its components are kept active in the balance sheet, which is defined in national tax and accountancy regulations. A system's economic life often differs from its technical life; technical life is typically longer than economic life. Second investments are made at the end of the longer technical service life; such investments are more cost-effective at this point than if they were made at the end of the (shorter) economic life. As a general rule of thumb, the residual value of a system with remaining technical useful life can be calculated by linearly prorating its initial cost. For example, a system with an expected technical life of 15 years that was installed 5 years before the end of the study period would have a residual value approximately 2/3 (= [15−5]/15) of its initial cost. This is comparable to the ISO 15686-5 (ISO 2017), USDOE Federal Energy Management Program (FEMP) LCC methodology, which requires that **residual values** (resale, salvage, or disposal costs) and capital replacement costs be included as investment-related costs. Capital replacement costs are usually incurred when replacing major systems or components, which are paid for using capital funds (Table 10.1).

A more detailed analysis should consider the lifetime of each major component. In the most cases, the selected study period will be less than the expected technical life of some major components. For these components, the residual value should be included in the LCCA. For components with a technical life that does not span the selected study period, reinvestments should be considered in the investment schemes.

Operating Costs An economic evaluation usually considers energy costs for the complete energy system (supply, distribution, and buildings) and the following operational costs:

1. Maintenance, operation, and management (including regulatory maintenance costs, e.g., repairs, replacement, refurbishment) are necessary to ensure that a building cluster and its energy supply and distribution structure function and can be operated properly throughout its life cycle. Maintenance activities usually include inspection, monitoring, testing, condition inspections, maintenance planning, repairs, refurbishment, and partial replacements. The evaluation may also consider indirect impacts of maintenance work such as costs due to downtime (loss of function for a period of time), which would include lost income in offices or hospitals and costs for onsite backup systems.
2. Insurance costs for building and component hazard, fire protection, pipe work, and electric installation.
3. Energy, water, and sewage costs.

Each scenario should consider the non-energy benefits from the following cost reductions, relative to the baseline scenario:

1. Energy cost reduction due to shifting energy peak loads, switching to different fuels (e.g., using cogeneration or tri-generation), or replacing fossil-fuel-based thermal or electrical systems with renewable energy systems

Table 10.1 Typical technical and economic life-cycle periods (LCP) for component groups

Component group	Technical LCP	Economic LCP
Thermal grids	40–60 years	20–30 years
Electrical grids (underground)	30–40 years	20 years
Heating supply station boilers	30 years	20 years
Heating supply station CHP	10–15 years	10 years

2. Maintenance cost reduction due to replacement of worn-out equipment before the end of its life cycle
3. Maintenance cost reduction due to downsizing of mechanical systems with reduced heating and cooling loads
4. Operation cost reduction using advanced building automation systems (BASs)

In some scenarios, energy use may increase compared to the base case due to new requirements for indoor air quality or thermal comfort. For example, adding cooling or humidity control requirements will result in additional energy use for cooling systems, which impacts the investment costs and LCCA. Maintenance costs for some systems may increase due to the complexity of controls system although such additional costs may be offset by reduced energy use resulting from more efficient HVAC system operation.

10.2.3 Improving the Cost-Effectiveness of Community Projects: Multiple Benefits

While a standard building LCCA broadly considers many operational costs, most cost-effectiveness calculations either on the building or the community level consider only energy cost benefits. However, ambitious energy investments often produce benefits beyond reduced energy consumption and peak demand shaving. Many of these additional benefits contribute to the objectives of organizations that implemented the projects and can have significant added value for those making investment decisions. Prior research has investigated such benefits as the impact of increased thermal comfort on the productivity of the building occupants or the willingness to pay increased sales prices or rental rates for higher-performing buildings (Jungclaus et al. 2017; Zhivov 2020); nevertheless, the monetization of non-energy benefits ("co-benefits") is still not broadly used on the building or building cluster level.

The first step to providing a systematic assessment of co-benefits is to list and classify potential benefits by their potential impact, the primary beneficiaries, first approaches for monetization, and the way that the measurement and verification (M&V) process can be conducted. It will be easier to monetize co-benefits using costs and benefits that have already been explored and quantified in the context of building LCCA and that provide M&V schemes.

Methods of quantification vary widely across benefits and depend on the desired accuracy of financial estimates. As yet, there are no standards for quantification, but to be included, the benefits must be measurable. A benefit's quantified value often depends on a combination of avoided costs relative to the base case and appropriate, conservative estimates. Of particular interest are high-value benefits that go beyond energy costs (e.g., labor costs, sick day costs) that can be reduced by providing better indoor environmental quality (thermal comfort, indoor air quality, natural lighting). The concept of non-energy benefits is still evolving; such benefits are being studied in different applications, and methods are being developed for their inclusion in building-level analyses. Although current methodologies do not yet consider building clusters, campuses, and communities, the methodologies in use for buildings could in some instances be transferrable to these larger aggregates.

An important requirement for co-benefits is their relevance to project financing. In other words, a benefit should be considered part of the equity rate that is necessary to gain access to a bank loan or other third-party financing. In a financial assessment of a project, this means that co-benefits are considered to be a revenue source, which can then be considered on the equity side of project.

Most of the benefits resulting from a refurbishment of the energy supply and distribution system relate directly to energy costs (e.g., improving the insulation of the grid, reducing the temperature level of the grid, reducing the volume per time).

The evaluation of grid refurbishment projects in Europe also indicates such additional non-energy-related benefits as:

- **Reduced maintenance costs for grids**: Repair costs of grids with more than 40 years of technical life often occur as the result of unscheduled emergencies with high repair costs. These costs can accumulate to comprise 1% of the first investment cost per year. Setting up a plan to refurbish grid sections with high flow volume or other mechanical burdens can reduce the number and severity of unscheduled emergencies while lowering annual costs of scheduled non-emergency repairs (0.25%–0.6% of first investment costs per year).
- **Leakage rates** can be reduced by implementing a repair schedule. Besides energy cost savings, the schedule should also consider the costs for water treatment and the risk of hazards from oxidative freshwater injections or limescale. The savings can be quantified in costs per unit of fresh water and the value of water chemistry components required to reduce limescale, oxidation, and other harmful water components.
- **Insurance cost reduction** resulting from improved backup systems has not been evaluated. There are not yet sufficient available data drawn from case studies to demonstrate a positive correlation between increased investments in resiliency and reduced insurance premiums. However, a simple assumption can be made for the resilience case: insurance only compensates the losses related to the insured hazard. If investments are made into resilient technologies and also into outdated or insufficiently reliable equipment, then when both scenarios are compared, the resiliency investment will show itself to be the more sufficient solution if: (1) it provides the necessary investments to increase resilience, (2) it reduces the probability of failure significantly, and (3) it meets most insurance companies' requirements for certain standards of maintenance and replacement (which will require investments anyway). From the perspective of a community energy supply company, the economically best strategy will be to invest in resilience to increase the availability of the energy system up to an affordable level and then, if necessary, to insure the remaining risks.
- **Feed-in values**: This is the value of the electricity quantity multiplied by the achievable electricity price in NPV. Grid usage includes the sale of electricity

from the community grid to the surrounding grid or to third-party customer. The latter is possible in countries with liberalized grid access where the usage of the grid can only be limited by the grid operator (DSO) if the feed-in is not fulfilling minimal technical standards (frequency, etc.) and the stability of the up-taking grid is in danger or the grid capacity is exhausted. In this case, the electricity production in the community grid must either to be stopped or stored. However, the grid operator can charge a grid usage fee, which must be evaluated in the LCCA. In some EU countries, the grid operators have time schedules with different usage costs in different specified time periods of a day.
- **Utility or independent system operator programs**: Independent system operator programs may provide additional benefits through demand response programs, which provide incentives to campuses to reduce campus power demands at the request of the regional utility or grid company. If the power demand reduction is provided for a longer time period, the "demand curtailment" provides additional benefits to the campus or community. The increasing numbers of detached power generators allow the grid company to provide incentives for the frequency regulation, in which the community or campus is required to use its systems (e.g., a CHP, chillers, batteries, etc.) to inject or absorb power over very short durations—on the order of seconds or at most a few minutes. The remuneration increases as the reaction time (time between call for action and reaction of the campus) decreases. Table 10.2 lists the major relevant cost benefits for building clusters and their supply and distribution schemes.

10.2.4 Decision-Making by Comparing EMP Alternatives

As it was stated in Sect. 3.4, one of the EMP alternatives, the **base case**, serves as a benchmark for LCCA of other alternatives. These alternatives might have different initial investment costs as well as different overall future cost savings, which could result in achieving better performance (e.g., greater energy use reduction, better environmental quality, and/or higher resilience of energy systems).

Net savings (NS) of an alternative relative to a base case is shown in the following formula:

$$\begin{gathered} NS = NPV\left[\Delta\, Initial\ investment\ cost\right] + NPV\left[\Delta\, Energy\ cost\right] + \\ NPV\left[\Delta Maintenance\ cost\right] + NPV\left[\Delta Replacement\ Cost\right] + \\ NPV\left[Incentives, rebates, tax\right] + \\ NPV\left[Benefits\ from\ resilience\ improvement\right] \end{gathered} \tag{10.1}$$

where NPV (Δ Initial investment [cost] ($)) is the present value of initial investment cost savings (or excess costs if negative) for the project relative to the base case. Initial investment costs are already in NPV if they occur in Year 0 of the study period.

Table 10.2 Multiple benefits in building clusters and their values

	Multiple benefit	Calculation method	Variations and values
1	Energy savings: effects from improving the energy performance	kWh savings x energy price	Fixed or flexible energy price; reductions resulting from demand-side measures and improvement of supply/ distribution schemes Energy demand reduction x energy price
2	Energy savings II	kWh RE replacing fossil x energy price (RE-fossil)	Fossils replaced by RE; calculation based on fixed or flexible energy prices energy demand x energy price reduction
3	Reduced maintenance I	Maintenance costs for replaced worn-out equipment at the end of its life cycle as a percentage of the new investment value	Average percentage value or end of life-cycle value maintenance cost reduction= maintenance cost of new equipment vs. maintenance cost of replaced equipment
4	Reduced maintenance II	Downsizing of investment in supply and distribution when demand-side measures are carried out, which leads to reduction of investment cost-related maintenance	A component downsized by 30% reduces maintenance costs of this component; in a first estimate a linear reduction can be assumed
5	Reduced operation costs	Building automation reduces operation workloads	Consider work plans and operation schedules individually. Cost savings from reduced daily staff costs
6	Insurance costs I	Replaced building components achieve lower premiums and improved protection against loss	EU: compared to pre-refurbished status, -2 up to -4€/m^2 on building surface area; distribution systems, n.a.; supply installations, 3–5% of total LCC
7	Independent system operator	Demand management and frequency management	Incentives for stabilizing the power demand by switching off and by frequency stabilization

NPV (Δ Energy [$]) is a present value of future energy cost savings for the project with the project life of N years, due to reduced use of electricity (E), gas (G), and other fuels (OF).

$$NPV\left[\Delta\, Energy\right] = NPV\left[\Delta E \times CE\right] + NPV\left[\Delta G \times CG\right] + NPV\left[\Delta OF \times COF\right] \quad (10.2)$$

where:

$C_{E,}$ $C_{G,}$ C_{OF} = unit fuel prices
ΔE, ΔG, ΔOF = annual electricity, gas, and other fuel saving

For each fuel type, NPV of energy cost-saving NPV can be calculated using the following formula (using gas as an example):

$$NPV\left[\Delta G \times C_G\right] = \left[\Delta G\right]_{t=1} \times C_{G(t=1)} \times \sum_{t=1}^{t=N} It \times \left[\left(1+d\right)^N - 1\right] / \left[d \times \left(1+d\right)^N\right] \quad (10.3)$$

where:

It = projected average fuel price index
$\mathbf{C_{G(t=1)}}$ **=** gas unit price in the first year

To simplify calculations, the energy unit price change from year to year can be assumed to be at a constant rate (or escalation rate) over the study period. The escalation rate can be positive or negative. The formula for finding the present value (**NPV [ΔG x** $\mathbf{C_G}$**]**) of an annually recurring cost savings at base-date prices ($\mathbf{C_{G(t=1)}}$) changing at escalation rate **e** is:

$$NPV\left[\Delta G \times C_G\right] = \left[\Delta G\right]_{t=1} \times C_{G(t=1)} \times \left(1+e\right) / \left(d-e\right) \times \left[1 - \left(1+e\right)/1+d\right)^N\right] \quad (10.4)$$

In Eq. 10.1:

NPV [ΔMaintenance ($)] is the present value of future maintenance cost savings.
NPV [ΔReplacement Cost ($)] is the present value of future replacement cost reduction.
NPV [Incentives, rebates, tax ($)] is the reduction in cost related to national or local incentives, rebates, and taxes.
NPV [Benefits from resilience improvement ($)] is the reduction in losses caused by interrupted power or thermal energy supply or reduction in insurance premium due to improvement system resilience. When the monetary benefits related to improved energy system resilience cannot be assigned, methodology described in Sect. 10.4 can be applied.

The formulas for calculating NPV [ΔMaintenance ($)] and NPV [ΔLease Revenues ($)] are based on the discount or inflation rate, d:

$$NPV\left[\Delta Maintenance\left(\$\right)\right] = \left[\Delta Maintenance\right]t = 1 \times \left[\left(1+d\right)N - 1\right] / \left[d \times \left(1+d\right)N\right] \quad (10.5)$$

where $[\Delta \text{Maintenance}]_{t=1}$ represents the maintenance costs savings in the first year.

$$NPV\left[\Delta Lease\ Revenues\left(\$\right)\right] = \left[\Delta Lease\ Revenues\left(\$\right)\right] t = 1 \times \left[\left(1+d\right)N - 1\right] / \left[d \times \left(1+d\right)N\right] \quad (10.6)$$

where [ΔLease Revenues ($)]t=1 represents the lease revenues increase in the first year.

$$NPV\left[\Delta Replacement\,Cost(\$)\right]T = \left[\Delta Replacement\,Cost(\$)\right]T \times (1+d)T \tag{10.7}$$

where [ΔReplacement Cost ($)]$_T$ is the equipment replacement cost saving in the year (T).

Equation 10.1 does not include an option of financing projects included into EMP. Therefore, there is no financing cost involved, and no need to account for the interest rate of financing.

When some part of the EMP is financed, the net savings for the project will include the capital cost financing. Different scenarios with private funds can be used to extend the capacity of limited public funds. However, these models come at a cost of capital cost financing. The cost of financing depends on the study period and the interest for borrowing money. Also, there might be a cost of project delay due to the time required for budgetary appropriations. Sometimes, this cost will exceed the cost of capital cost financing.

Each term in Eq. 10.1 can be calculated in terms of net present dollars ($) or constant dollars ($). Instead of calculating the NPV of each term, this can be simplified by using economic scalar ratios (SRs) for energy and scalars (S) for maintenance and replacement. This simplification avoids the difficulty of selecting all of the individual economic parameters in determining the cost-effectiveness of projects, thus establishing a comparative economic feasibility threshold for analysis.

Also, Eq. 10.1 does not include revenues that can be harvested when electrical and power energy is sold outside the campus to external customers or to the grid, which adds the value of the electricity quantity multiplied by the achievable electricity price to the NPV.

10.3 How to Calculate Risk and Resilience Costs and Benefits

A long-duration power interruption and loss of thermal energy, especially in extreme climates, may significantly degrade regional and even national security (e.g., due to the loss of critical infrastructures or degrade critical missions at military bases). It can also affect the health and safety of a community and even result in a loss of human life (Viscusi and Aldy 2003).

While the cost of a given resilience measure is well understood (e.g., the costs of labor and materials to "underground" power lines), the resulting benefits are more difficult to assess, particularly because of a lack of supporting data (LaCommare et al. 2017). Although resilience has currently been acknowledged as a distinct benefit, its value has typically not yet been quantified.

Murphy et al. (2020) argue that the types of data that would support the benefits associated with resilience measures are difficult to collect because of the time and types of events needed to demonstrate the value of resilience investments. For example, 100-year flood events happen so infrequently that the benefits of mitigation measures associated with those events are difficult to quantify in a realistic timeframe. Moreover, even if the health, safety, and economic impacts of a threat could be quantified, it is very challenging to translate those impacts into financial consequences that will ultimately indicate to a given stakeholder whether a change in investment or operations is warranted.

10.3.1 Practical Approaches for Resilience Value

Resilience remains difficult to value because the desired future resilience needs do not mirror past needs. In the example of energy savings, the savings profile from an examination of past energy costs, future energy expenditures, and expected use variations is included in a baseline adjustment. In the following discussion, a standard case of the energy baseline adjustment is shown and pasted into the calculation of resilience values.

A standard case of energy baseline adjustment includes:

- Energy consumption baseline for a building operation 9 am–5 pm: 100 units of energy
- Ex-post-retrofit energy demand of the building (9–5): 50 units of energy
- Energy savings from retrofit: 50 units of energy

If we assume that the building operation hours are extended, this can be reflected in the energy baseline for the extended operation hours from 9 am to 11 pm as 120 units of energy.

Then, if the post-retrofit building uses 55 units in the 9 am–11pm operational scenario, ex-post energy savings of the building is (120 – 55) or 65 units of energy. The example shows that adjustments to the building usage must be stated in adjustments to the baseline.

Resiliency must be examined using the same methodology as the baseline adjustment shown above: assumed operational cost baseline for a building in the ex ante status of any resiliency measure is 100 units. To protect the building and its systems against additional threats (weather, terrorism, increased reliability expectation, etc.), the building operational cost baseline must be adjusted in the same way as shown above for additional usage hours.

10.3.2 Practical Approaches for the Resilience Value (2)

One very common way of quantifying energy resilience is measuring the amount of time that a critical load can be met at a certain probability. It is quantified as a probability because the load and solar resource varies throughout the year, so the length of time the load can be sustained will change depending on the time of the outage.

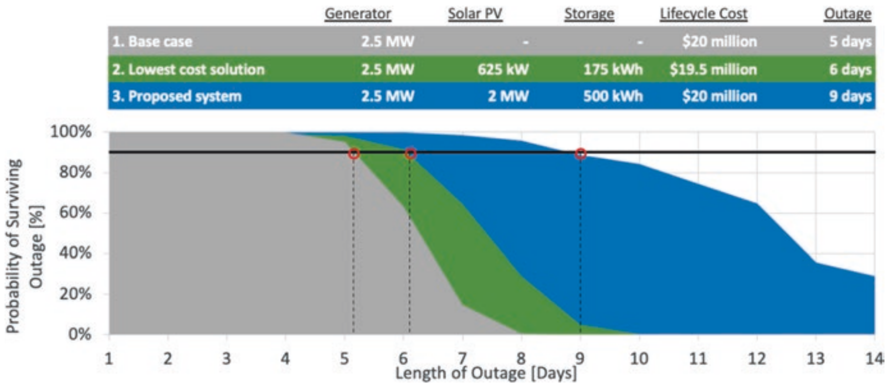

Fig. 10.3 The probability of surviving varying outage durations with different energy systems and costs (Anderson et al. 2017)

Cost-Neutral Approaches In some cases, an energy system that is cost neutral (i.e., utility bill reduction benefits over the system lifetime equal the capital and operating costs) can provide significant resilience benefits. Anderson et al. (2017) present such an example for a military base with a baseline energy life-cycle cost of \$20M and an existing 2.5 MW backup diesel generator system. By installing 625 kW PV and 175 kWh li-ion energy storage system, the base could save roughly \$500k over 20 years (in present value terms) and increase the outage survivability from 5 days to 6 days, with 90% probability, by extending fixed onsite diesel fuel supplies. If the \$500k in savings is used to increase the PV and storage system capacities to 2 MW and 500 kWh, respectively, then the outage survivability increases further to 9 days (Fig. 10.3). This is known as "resilience for free" because the additional survivability is achieved with no increase in life-cycle cost of energy.

Non-Cost-Neutral Approaches (1)
In other cases, resilience cannot be achieved for free. In these cases, sustaining the critical load during an outage requires investment in assets that will not provide enough utility bill reductions over their lifetime to offset the upfront capital and operating costs. In these cases, it is important to consider the resilience value that the system provides. Without backup power, the site would incur costs from the outage such as spoiled goods, damaged equipment, or lost productivity. When a backup power system helps a site avoid these outage costs, the avoided costs can be incorporated into the economic cost-benefit analysis.

Non-Cost-Neutral Approaches (2)
The case study described in Yamanaka (2020) shows how a win-win approach can be successfully implemented to improve electric system resilience through collaboration between the Army Garrison and the regional utility. Through the Utility Enhanced Lease, the utility was allowed to set up a 50 MW CHP power plant on the land of the Garrison. By avoiding long land grid connections (with higher failure

probability) and providing onsite power supply 24/7, the resiliency issue of the Garrison has been successfully resolved. The value has been estimated to be comparable to the value of the ground on which the utility installed the 171 MMBtu/hr (50 MW) unit and, due to local land scarcity and other factors, equates to $360k/yr. These values might differ in other regions, but the idea of putting a value on the resilience in this case has been resolved to the benefit of both sides.

The Value of Lost Load (VoLL)

The cost of an unmet unit of energy is commonly used in bulk power system analyses as a proxy for consumers' willingness to pay for avoiding an outage (see, e.g., Schröder and Kuckshinrichs [2015]). VoLL is also used in bulk power system markets as an upper limit on the wholesale price of energy. Analysts at NREL have recently incorporated VoLL into a behind-the-meter (BTM) distributed energy resource (DER) model for cost-optimal sizing and dispatch of DER called REopt (www.reopt.nrel.gov, Laws et al. 2018). In this context, VoLL acts as the site-owner's proxy for the value of resilience and is balanced against the microgrid upgrade costs (the cost to make a DER islandable from the grid). Accounting for VoLL can make a project cost-effective in some cases.

Figure 10.4 shows an example where accounting for VoLL can make an otherwise negative NPV positive. This scenario models a hospital located in Pacific Gas and Electric's service territory. Using the REopt Lite Webtool (www.reopt.nrel.gov/tool), we optimize a system to meet a 14-day design outage and 75% critical load at a minimum life-cycle cost. The best bill savings can be achieved with a combination of a 2297 kW PV array, 1,433 kWh capacity battery, and a CHP system with a 534 kW reciprocating engine. The NPV of the energy system is $2.6M before accounting for the microgrid upgrade cost. The estimated additional cost of microgrid components required to island the system is $3.04M. This reduces the NPV of the project to approximately -$440k. However, if we include a $750/kWh VoLL, the avoided outage costs are $700k, resulting in a final, positive NPV of $250k. This shows that it is important to include the full costs and benefits of the system when assessing project economics.

While VoLL is a useful concept for valuing resilience in theory, monetizing this value can be approached in at least two ways:

1. ***Value determination by insurance costs***: For public and private energy users and producers, insurance premiums they have to pay to cover loss of utility revenue, grid damage, and cost of recovery as well as loss of assets, perishables, or business can be considered as monetizable indicators of the value of resilience. In this context, the full scope of the insurance cost must be considered; insurance companies often claim minimum requirements for the components that they are asked to insure, especially when the components in focus are variable. Any costs incurred to make components "insurance-ready" must be considered.
2. ***Value determination by standards***: In regard to military applications, since DoD requires the installation of a standalone diesel generator at every building that houses a critical load, Marqusee et al. (2017) argue that the cost of a standalone

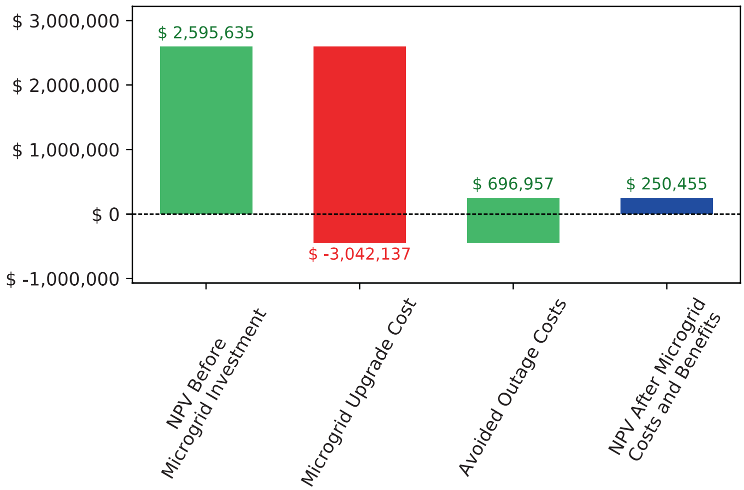

Fig. 10.4 Costs and benefits of a hybrid PV, battery energy storage systems (BESS), CHP system with a 40% microgrid upgrade cost, and $280/kWh VoLL for a 14-day outage

diesel generator (including upfront capital, O&M, and incremental fuel costs) should "represent the value (price) that DoD places on energy security."

Practical approaches for the resilience value (3): Lost-income method. To illustrate the practical use of an EMP design, one example power supply system on a ***health care campus*** shows the different steps of the risk analysis and the potential conclusions. This first stage does not examine the quality criteria of the power supply system in detail. The calculation measures the OPEX losses of the power supply system in "lost income per day and bed" (LIPDB). The risk evaluation is done for several different scenarios:

1. **Base case**: A hospital with a peak load of 10 MWe is connected *to one line* of the mid-tension grid providing factor 1.2 of the peak-load capacities of the campus. Each line has a demonstrated availability of 99.1% in terms of frequency, load, and stability. The calculated probability that considers construction issues results in a total availability of 98.8%. A total LIPDB is assigned a value of 390 (i.e., all 390 beds are unoccupied for 1 day). Costs are calculated by the load costs (€/kW) 10 MW x 1.2 x 20 €/kW =240,000 €/yr. The utility contract provides the right for the costumer to reclaim costs occurring on natural hazard events.
2. **Availability plus**: The hospital is connected *to two different* lines of the mid-tension grid providing factor 1.8 of the peak-load capacities of the campus. Each line has a demonstrated availability of 99.8% in terms of frequency, load, and stability. The calculated probability that considers construction issues results in a total availability of 99.1%. A total LIPDB is assigned a value of 290 (i.e., all 290 beds are unoccupied for 1 day). The incremental availability costs are calculated using the additional load costs (€/kW) in comparison with the base case and the additional transmitter station capitalized over 20 years: 10 MW x (1.8 –

1.2) x 20 €/kW = 120,000 €/yr + NZV (90,000 €, 4%, 20yrs) 7,200 €/yr.= 127,200 €/year. The improved LIPDB is 100, which equates to 80,000 €/yr. Availability plus is not paid back by the reduced losses.

3. **Availability 1 plus CHP**: Basic scenario + CHP with quick start functionality. NZV of the CHP is 42,000 €/year; since the potential use of the CHP occurs for only a short time, fuel costs need not be considered. With the same availability as in the previous two scenarios, the LIPBD of this scenario is cost-effective and even generates a positive income in the event of a hazard.

10.4 Methodology of LCCA Analysis of Energy Systems with Enhanced Resilience

Based on the discussion of different resilience value approaches in Sect. 10.4, this chapter provides one example of a potential approach to comparing different resiliency approaches from the LCCA perspective. LCCA of energy systems supporting mission-critical operations for new construction and energy system upgrade projects and additional non-energy-related measures protecting these systems (e.g., burying power cables, building flood walls around equipment, raising mounting level, or installing equipment inside buildings) must be performed against the base case described below. If the “baseline model” in 10.3 is used, the base case can be the system that is operated under comparable resiliency assumptions.

For new construction projects, the base case scenario for comparing different energy systems’ alternatives should include systems for power and thermal energy supply in non-emergency operation modes and individual building energy supply systems for emergency operation modes, i.e., distributed backup diesel generators, UPSs (as needed for the mission), and fuel storage.

The configuration of the base case emergency generation and storage systems and the level of redundancy of major equipment should be adequate to meet the energy requirements for mission-critical and safety and health operations for the specified common threats (identified through risk assessment for the specific location), where capacities to meet minimum requirements (maximum downtime, power, and thermal energy quality, etc.) are specified by Federal agencies. Calculations should include recurring purchase of equipment and the cost of adequate systems testing and maintenance as well as cost of fuel used for testing and replacement. Figure 10.5 illustrates the concept of the base case used for LCCA.

The base case scenario shown in Fig. 10.5 for the new construction group of graphs (on the left side of Fig. 10.5) is a combination of the single-building heating and cooling systems with the power supply from the grid. Because the building hosts a critical mission, to increase resilience of energy supply, energy systems used during non-emergency operation mode are supplemented by backup diesel generators, UPSs, redundant boilers and chillers (to achieve, e.g., N+1 redundancy), and fuel storage for 14 days operation (or other period of time as specified by Federal

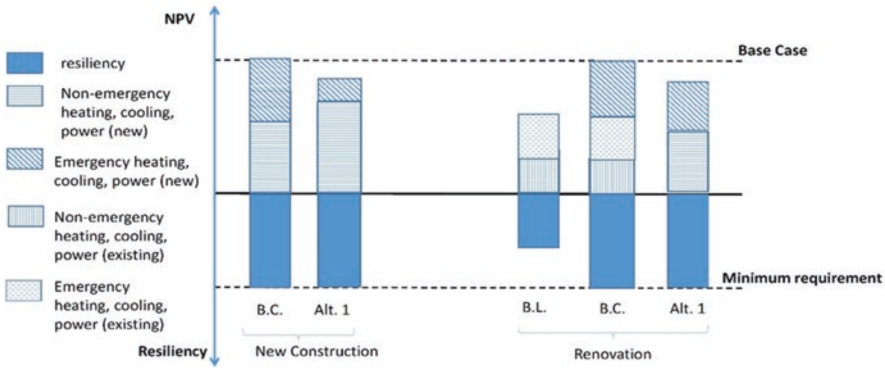

Fig. 10.5 Concept of LCCA for new construction and renovation projects

agencies) in the emergency mode. All equipment serving the building are provided with adequate maintenance and testing of emergency generators and with fuel supply for equipment testing and fuel replacement.

Alternative 1 used as an example in Fig. 10.5 is designed to increase the building's energy efficiency by reducing the need for heating, cooling, and lighting. A CHP plant provides the building's baseline heating and electricity needs. Excessive waste heat is stored in a mid-term storage, which permits peak shaving and allows for a reduction in the size of the heating equipment. The remaining heating and cooling needs are provided using heat pumps powered by electricity. Additional power during the normal operation mode is provided by the grid. To shave peak loads during the daytime and thereby reduce electricity costs, large-scale power batteries are charged during nighttime and over the weekend. Emergency operation mode energy needs are served by CHP plant and HPs complemented by a smaller emergency generator. The Alternative 1 architecture is designed to meet resilience requirement similar to the base case but has smaller life-cycle costs due to reduced size of emergency generator, smaller fuel and fuel storage costs, the elimination of peak electricity costs during regular operation, and the reduction in fuel use resulting from the use of waste heat from the CHP.

For renovation projects with energy systems upgrades (right three graphs in Fig. 10.5), it is first necessary to establish the baseline of the existing energy systems and to analyze their resiliency to the most relevant local threats. The resilience of these systems depends on their architecture, type and age of equipment used, and the historical level of their maintenance and level of protection against the most relevant local threats. Typically, the resilience of energy supply systems serving a building built to previous requirements will not be sufficient based on current regulations but will have relatively smaller operation and maintenance costs. The scope and cost of upgrade to the **base case** architecture of the system should be based on the identified gap in the systems' capacity and resilience and should be based on the minimum requirements specified by Federal agencies. Additional distributed backup diesel generators, UPSs, and fuel storage will be added if necessary. In the LCCA of renovation projects, a comparison of systems' alternatives should include the residual value of existing equipment and distribution systems, their remaining useful life, and the cost of maintenance corresponding to the age of equipment. In the base case alternative, the resilience of the energy supply system will be brought up to minimum requirements specified by Federal agencies with the corresponding life-cycle cost increase compared to the pre-renovation baseline.

Alternative 1 will be developed similarly to the way described for the new construction case, with limitations on energy efficiency improvements and with the use of some of the existing equipment when cost-effective. The architecture of Alternative 1 is designed to meet resilience requirement similar to the base case.

Recommendations:

1. Configuration of the base case of emergency generation and storage systems and the level of redundancy of major equipment shall provide adequate resiliency for the specified common threats (identified through risk assessment for specific location) with capacities that meet the minimum requirements specified by the national framework.
2. Alternative cases shall provide a level of resiliency that is the same or better as that of the base case.
3. In both new construction and renovation, life-cycle cost analysis of alternatives shall be made against the base case scenario. System architectures to be compared may include those servicing individual mission-critical operations (distributed system solutions), and clusters of mission-critical and safety and health-related operations/facilities or areas, which include both mission-critical and non-critical operations. Life-cycle cost analysis shall include all systems providing power and thermal energy to facilities served throughout the year-round cycle including non-emergency, emergency, and testing operation modes.

10.5 LCCA Variation Calculation: Economic Key Risk Factors (KRFs) and Key Risk Indicators (KRIs) for Community Energy Systems

The decision-making process underlying the implementation of an EMP is comparable to the processes supporting any other investment decisions needed to provide variation analyses, i.e., they are based on assumptions regarding the relative prices, taxes, and benefits of community energy systems under consideration. To overcome the challenges of providing energy supply and distribution systems for building clusters, it is first helpful to identify a simple set of KRFs identified using the risk evaluation processes described above. In practical terms, identifying KRFs is essential to achieving an EMP project's economic targets. Interviews with 18 project facilitators, ESCOs, financiers, and insurance companies identified the following KRF:

1. **Investment costs**. Investment costs, usually the "first investment costs," are single payments made at the beginning of the project to pay for design, equipment components, and labor. To integrate these costs into the annual cost-based cash-flow scheme, the investment costs are transferred by annuity factors into equal annual *capital costs* of the calculation period, which contain both interest costs and payback. In EMP projects, the capital costs usually capture a large portion of the total costs. For NZE projects, investment and capital costs usually comprise the largest costs in the overall cash-flow scheme. This means that relatively small increases in investment costs may significantly impact cash flow.
2. **Energy cost**. Energy costs can be accounted for as direct cost or as cash-flow income (based on cost savings). If considered as income, the performance of the energy savings plays a pivotal role in the cash flow such that any large compromise to energy savings may significantly impact the cost-effectiveness of the project's cash flow.
3. **Maintenance cost and other life-cycle costs**. In the evaluated case studies, the "other" life-cycle costs do not comprise more than 20%–25% of the total costs. However, insurers (especially) and ESCOs that are responsible for long-term functionality of the energy systems indicate a strong relationship between availability of energy systems and its maintenance and operations schedule.

Finally, a series of indicators are necessary to monitor the operational risk management model. KRIs are statistics or parameters used to anticipate changes in the exposure of projects to risks. Typically, these indicators are regularly checked since they provide alerts to changes that may reveal negative patterns of risk exposure. The main goals of the KRI methodology are:

- To provide information on level of operational risk to multiple projects and to identify the main causes of any changes
- To set warning levels and limits for decision-making
- To identify and measure the effectiveness of controls and any improvements made
- To identify correlations between KRIs and operating losses

Recent risk analyses one for national and international EMP research projects for building clusters, communities, and hospital and university campuses have identified the KRIs listed in Table 10.3. The KRIs vary widely from country to country depending on each country's energy and investment costs. To date, relatively few projects with consistent and comparable parameters have been evaluated. For example, data from only six projects in Germany are publicly available. It is recommendable to evaluate as many national case studies as possible to gather reliable KRIs over time.

De-Risking Methods and Tools in EMP for Building Clusters

From the economic point of view, the design and execution of de-risking measures in different stages of EMP development are crucial for the EMP's success. The following paragraphs focus on de-risking measures for the KRFs of investment and energy costs.

Table 10.3 Key risk factors, indicators, and values

Key risk factor	KRI	KRI values
Capital costs for energy supply and distribution	Specific costs overall for the building cluster[a] Specific investment costs per m^2 total gross floor space of the building cluster Investment costs per kW thermal or kW electrical maximum load	Evaluates and compares the total investment costs for the energy system (building and supply). Sources: ST B results
Energy savings	Specific capital costs per kWhth or kWh el saved per year Energy cost savings/m^2 yr. (per total gross floor space)	Evaluates the cost of investments per kWh saved to compare between different scenarios and investments
Energy costs	Energy costs per m^2 (per total gross floor space of the building cluster)	Value in use in facility and energy management processes for single buildings, building clusters, industrial parks, etc.

[a]Reference investment costs including demand side measures (buildings), grids, and supply buildings

Evaluation of De-Risking Measures: Total Cost of Risks
Risks can be quantified, as can de-risking measures. Different risk factors are characterized by different levels of risk; similarly, the level of de-risking depends on the identified risk costs (cost of losses) that may occur in the most probable risk case and the cost to mitigate this risk to a certain level. A cost-benefit analysis is necessary to be able to decide if (and to what level) a risk can be mitigated. For effective risk management, the total cost of risk is made up of two elements:

- Cost of insured risk (CostIR), which corresponds with the insurance policy premium or any other measure put in place to compensate the identified risk
- Cost of uninsured risk (CostUR), which corresponds with the loss borne by the project

The total cost of risk (TCOR) is then:

$$TCOR = CostIR + CostUR \tag{10.8}$$

Both components will be defined by both the retention levels (“R,” loss levels below which losses are borne by the project) and the insured limit (“L,” maximum loss covered) of the insurance scenario:

$$TCOR = CostIR\left(R,L\right) + CostUR\left(R,L\right) \tag{10.9}$$

This equation may be used to set up and compare risk management strategies in terms of the cost-effectiveness of de-risking measures.

10.6 Business Models

10.6.1 Introduction

Backcasting and forecasting techniques (shown in Fig. 10.6 and described in Sect. 3.11) are two major concepts applicable to the development of EMP implementation strategies (Zhivov et al. 2014; Annex 51 2011; Kimman et al. 2010).

Backcasting denotes the process of defining milestones (mid-term goals) and determining the necessary steps to reach the final goal. Backcasting allows concrete actions in the short term to be formulated from the long-term goals. Forecasting, by contrast, refers to the planning of projects to meet milestones defined through the backcasting process, i.e., setting project requirements, and optimizing and designing projects and sets of projects in a holistic way that is geared to meeting each milestone.

In practice, the implementation of EMP project requires forecasting approaches to ensure that the design of the EMP matches the project's final goals. Planning and execution of the EMP projects can spread over multiple years based on the mission requirements, funding limitations, and sources of funding available. To meet the overall targets in the given limitations (time, budget, qualitative targets such as resilience level, etc.), a strict monitoring process is required on (at least) an annual basis. This monitoring includes a comparison of the target and performance levels and the development of corrective measures for recognizable target deviations.

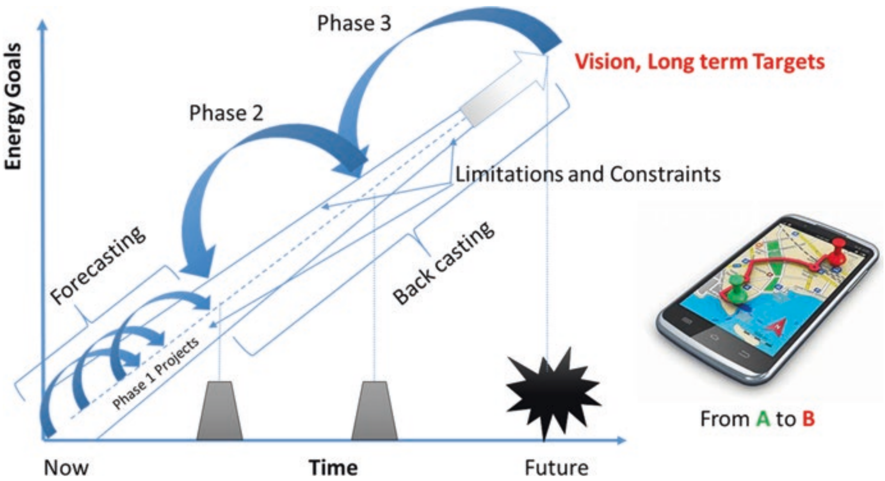

Fig. 10.6 Energy master planning: backcasting and forecasting

10.6.2 Context and Technical Scope of the EMP in Communities

The technical scope of the EMP may be limited to some degree of improvement of the energy efficiency of the communities' building stock; or it may broadly include demolition and new construction, along with refurbishment or reconstruction of the energy supply system including its energy generation, energy distribution, and energy storage components.

EMP is not usually carried out as a standalone activity but as a part of the partial or complete constructive redesign project that opens the technical scope to a spectrum of non-energy-related projects, e.g., demolition, new building construction, and measures to improve utilities and to enhance the resilience of buildings and their infrastructure (including energy systems) to withstand design-based threats. The best-practice approach to integrating an EMP into the larger design context occurs after the spatial and architectural concept has been fully developed. This means that the community's usage concept has been developed to the level of individual buildings and their infrastructure so that the future floor space of single buildings is, at least conceptually, determined and described.

The EMP will be set up based on the status-quo baseline of energy consumption, the use and construction of the redesigned buildings, and a first draft of the infrastructure plan, which includes the energy delivery infrastructure and other pathways, intersections with the power, gas, or district heating grids outside the community.

As described in Chap. 3, the EMP will preselect potential technical scenarios for the energy supply and the energy demand side, and then start the modeling phase. The EMP models will be recalibrated according to the baseline consumption of the status-quo community. The model will consider the investment and life-cycle cost assumptions provided in Chap. 1 based on the different energy system components and on demand-side measures determined by the level of building and distribution grid insulation.

Although the decision-making process primarily considers cost-effectiveness, the life-cycle cost evaluation focuses on a cost-effective solution that provides the most benefits at the lowest cost. The planning and execution of such complex projects can spread over multiple years based on mission requirements, funding limitations, and sources of funding available.

The technical scope of an EMP project aiming at NZE will at least replace or refurbish old systems, using four relevant measures typically in use:

1. Demand-side measures:
   (a) Buildings: minor renovation and commissioning that aim to yield <50% savings of heating and cooling energy compared to the baseline of the reviewed buildings
   (b) Building: major renovation with a deep energy retrofit that aims to yield >50% of heating and cooling energy compared to the baseline of the reviewed buildings

   (c) Process heating/cooling: reduction of heating/cooling demand for processes (mostly independent from heating degree days such as DHW, physical and chemical hot water-/steam-supported processes)

2. Energy supply (centralized/detached/partly centralized) measures:

   (a) High-temperature-systems: steam boilers, medium to large CHP plants with steam extraction on various pressure and temperature levels (>120 °C [>248 °F])
   (b) Mid- to high-temperature systems: boiler/ CHP/CHCP on natural gas, oil, coal or lignite, or solar basis (70–120 °C [158–248 °F])
   (c) Low-temperature systems: condensing boilers, electric, gas, or solar-driven heat pumps with different ambient heat sources (<70 °C [<158 °F])
   (d) Energy distribution for heating, cooling, and power, including exchange and housing stations for the handover of the distributed energy
   (e) High-temperature system grids for steam and hot water >120 °C (>248 °F) with/without condensate return
   (f) Mid- to high-temperature system grids for hot water with temperatures between 70 °C and 120 °C (158 °F and 248 °F)
   (g) Low-temperature systems for hot water with temperatures below 70 °C (158 °F) in the average of time (partial exceedingly, e.g., for hygienical requirements for DHW supply systems, etc.)
   (h) Cold-temperature systems for the distribution of water or refrigerants for the use of low- or cold-temperature geothermal heating sources for centralized or detached heat pumps with temperatures below 40 °C (104 °F) in the average of the year.
   (i) Cooling distribution systems with average temperatures <20 °C (<68 °F) containing cold water or refrigerants
   (j) Power grids for low-middle tension systems in or above ground level including transformer stations to the next tension level
   (k) Gas with low to middle pressure and transformer station to the next pressure level

3. Storage systems:

   (a) Thermal high-medium or low-temperature storage with insulation for the optimization of the performance of load peaks and time of operation for CHP/CHCP/biomass and heat pumps. (Usually 1–4 hrs of load output capacity of the relevant component can be stored and kept with small losses.)
   (b) Thermal seasonal storage for high- to medium- or low-temperature storage with low level insulation and high capacity of, e.g., the overproduction of solar thermal fields to be available in the heating season
   (c) Power storage systems based on onsite solutions that use batteries with 1–3 hrs storage capacity or that use power production from PV panels to be made available in periods of high-demand time in the same or next day; also often used as a storage/charging system for e-mobility

(d) PtG-storage systems with >5 MW power capacity that can convert overproduction from medium to large PV fields to synthetic gas fuel

4. Resilience measures:

   (a) Cross functional surpluses that help to meet the increased resilience requirements of energy supply and energy distribution systems. Energy demand measures are considered to reduce demand and contribute to the overall availability of energy systems and buildings (e.g., insulation increases that slow the loss of heat in cold climates in the case of a heating supply outage).

10.6.3 Selection of Business Models in Community Projects

The selection of the business models must be considered from the standpoint of the users, who are the public community owner(s)/manager(s), etc. The business model that is most relevant is one that best serves the users' needs, i.e., that provides the most suitable services and technical scope, a remuneration model that matches the users' financial situation, a monitoring and verification system simple enough so the user can understand and handle it. Users need not have a deep understanding of business model theory; an appropriate business model can be selected for a community by simply using a profile of services and requirements that match the users' expectations.

The following sections summarize different services that correspond with typical EMP projects and the major risks to be considered in the selection of a business model. The resulting profile can be used to create statement of work (SOW) documents during the tendering processes and to cross-check with standard business model contracts.

10.6.3.1 Scope 1: EMP Design Phase

In the very beginning, after defining a concept, it is necessary to consider where to allocate the design phase. In many performance-based business models (ESPC, utility models, etc.), the service provider (e.g., energy service company [ESCO]) will take only the performance risk—if the service provider is responsible for the design phase. (This is not as relevant in other business models that do not involve performance-based remuneration.) The following design services should be considered:

1. Acceptance and finalization of the EMP modeling
2. Finalization of the design that is ready to execute
3. Definition of the scope of work and the specifications
4. Avoidable risks, e.g., lack of quality assurance in the design phase may lead to significant investment cost increases and reduced cost-effectiveness

10.6.3.2 Scope 2: Implementation Preparation Phase

The complexity of the legal framework, requirements from public authorities, environmental issues, and other processes often motivate communities to decide to delegate larger parts of the implementation preparation to third parties such as planners, utilities, ESCOs, etc. Such preparation may include:

1. Listing all allowances pertaining to spatial, environmental, and other legal restrictions
2. Procuring the specification until hiring and signing of executive contractors, ESCOs, etc.
3. Risks: Additional investment required to receive the allowances may increase the total investment costs and reduce cost-effectiveness; the procurement process itself may lead to higher investment costs and reduced cost-effectiveness

10.6.3.3 Scope 3: Financing Phase

The financing phase may involve:

1. Preparation of financing decision-making pertaining to cash flow, investment planning, and calculation of risk variation
2. Setup of the financing scheme as a combination of equity, third-party money, and potentially available subsidies and loan guarantees
3. Signature of financing contracts, loan securities, and loan guarantees
4. Risks: Fluctuations in interest rates in the period between decision-making and execution of the financing introduce the potential risk of additional financing costs

10.6.3.4 Scope 4: Construction Phase

In most cases, construction will be delegated to third parties such as contractors or ESCOs; the community will often also hire architects, planners, third-party engineering firms, or project managers to monitor such aspects of the project as:

1. Setup of construction site
2. Implementation of the installation design, usually done through contractors and subcontractors during design and specification
3. Overseeing project cost and time management over specified time periods
4. Ensuring quality assurance in the implementation process
5. Performing interim and final functionality tests, obtaining project owner and customer approval
6. Performing cash management
7. Risks: Increases in investment costs and/or delay in construction phase, e.g., by unforeseen technical issues, incomplete design, unavailability of subcontractors,

delays in the time schedule, and bankruptcy of contractor; all these circumstances can generate additional financing needs and costs and can reduce the cost-effectiveness of the EMP

10.6.3.5 Scope 5: Operation Services

To some extent, military or other restricted areas cannot hand over the operation of installations' systems to third parties. If operation services are of interest, the following subtasks help to define what is needed and what the installation or facility staff can provide. In many cases, services can be combined. For example, utility services often provide 24/7 operation, which can help to reduce staff costs in the community. Operation services include:

1. Setup of operation, first adjustments, and optimization
2. Setup of operation schedule and building to accommodate internal and third-party operating staff
3. M&V plan and execution and system adjustments in accordance with modeling results and practical experience
4. Planning and execution of maintenance and refurbishment activities and monitoring of maintenance and refurbishment costs
5. Cash-flow management
6. Reporting to involved key stakeholders: financiers, community owner/admin, and others
7. Major risks: Disturbance of energy supply endangers mission and function of the community and/or single buildings with consequent negative impacts on cash flow; performance indicators will not be achieved, which increases the operational costs and reduces the cost-effectiveness and financial performance of the project

10.6.3.6 Scope 6: End of Term Phase (In Project with Fixed End of Term Definition)

In a project with a fixed end of term, this phase involves:

1. Determination of the residual value
2. Deconstruction of relevant components
3. Finalization protocols to approve the handover of the site, components, and documentation according to project specifications
4. Major risks: If the residual value is less than assumed (e.g., due to poor maintenance), the cash flow and the financial performance indicators will be compromised

Table 10.4 lists the advantages and disadvantages of different business models. For many public agencies and communities, it is important to reduce the number of

Table 10.4 Community business models

Business model	Description	Pros	Cons
Appropriated funds	Funds appropriated by the governing agency as part of the yearly budgetary process, execution supervised by agency and subcontracting parties	Straightforward; follows the normal processes for capital improvement program Can be done incrementally for several years Manage resource to highest priority areas	Subject to normal budget priorities Must be managed internally Follows normal design-build processes, makes no extended guarantees No energy performance guarantees No budget limitation guarantee
Fixed payment	Funded by a utility. Paid back via fixed payments on the utility bill or on the property tax bill	Easily implemented Usually low interest rates Payment stays with the property in case property is sold	No energy guarantee Usually limited to small projects EMP implemented in pieces
ESPC	Energy savings performance contract	Budget neutral Energy/operations savings pay for the upgraded systems. Third party manages the contract Energy savings are guaranteed, resulting in lowered financing rates Multiple technical updates can be built in	Not readily understood by many municipal officials Typically need a 3rd-party expert to advocate for the customer Long approval cycles on final project/ financing by customer Concerns by some decision-makers on long-term debt
UESC	Utility energy savings contract	Budget neutral Energy/operations savings pay for the upgraded systems. Third party manages the contract Customer contracts with their utility (people they know) Customer decides level of energy guarantee	Not readily understood by many municipal officials Typically need a 3rd-party expert to advocate for the customer Long approval cycles on final project/ financing Concerns by some decision-makes on long-term debt Not all utilities offer this service

(continued)

Table 10.4 (continued)

Business model	Description	Pros	Cons
Blended funding	Combing appropriated funding with ESPC/UESC	Same as ESPC/UESC Shorten financing term by injecting one time or multiple cash payments Can get more ECMs in the project	Same as ESPC/UESC Ensuring that the cash payments are available in the budget
PPA	Power purchase agreement (buys power from a non-utility partner or developer)	Developer pays all costs Customer buys power at a price At the end of the contract period, customer can buy the equipment for fair market value or have it removed Developer may pay a lease payment to use customer land Consistency of long-term budget planning	Long-term procurement contract (typically 20 years) for customer Energy prices may be fixed or escalated Locked in prices result in not being able to take advantage of potential future lower pricing
EUL	Enhanced use lease (customer leases underutilized land to a 3rd party in exchange for resiliency)	Developer pays all costs Lease payment is often "in kind consideration," which is often required or needs customer infrastructure updates If utility power is lost, the power being produced on the leased land is sent to the customer	Lease is 30–40 years Power from the leased land is sold to the utility grid or may be bought by the customer Land is unavailable for future customer expansion

parties involved to minimize the effort required to manage these parties and to avoid the complex interactions between the different activities that each party is committed to perform. Table 10.4 also lists the number of different parties involved in the process to fully describe all six stages. The following section further describes the different business models.

10.7 Description of Most Common Business Models for Communities

10.7.1 Appropriated Funding and Execution Model

Funding Mechanisms This model assumes that government agencies or public administrations (e.g., universities, public housing companies) are responsible for budget planning and execution of the investments in their building stock and campus-level utilities. The budget may include public equity (tax payments, etc.) and dedicated bank loans. In most European countries, however, bank loans are limited by a public debt ceiling that is related to the available equity of the public body.

In the budget planning stage, building refurbishment and utility modernization projects compete with other tasks that a public entity must fulfill. These projects are not usually first priorities on the national, regional, and municipal levels. Thus, the selected model often has limited appropriated funds to renovate existing buildings, repair aging infrastructure, plan for disaster preparedness and resilience, or perform energy upgrades. Agencies typically have some funding available for specific building improvements under programs like (in the United States) the DoD's SRM program. Resilience ECMs that remain unfunded for years leave the facilities at risk and unable to operate in the event of a major weather event, a cyberattack, or some other critical, crippling event.

Main Responsibilities and Risk Distribution In this model, campus owners take responsibility for projects' design, implementation, operation, management, and financing. However, these activities are often subcontracted although the general management responsibility remains with the campus owners, who take full responsibility and assume liability for both the quality of the project and the economic return on their investments. The campus owner controls contracting, component and systems selection (and hence the project price), and project management. The campus owner is fully liable for the project's subsequent economic performance (i.e., volume of energy required to deliver post-retrofit living conditions), and for the financing (which is possibly secured), but not directly for the overall energy performance. By assuming the risk for all the project components, the campus owner is well placed to benefit from any economic outperformance (i.e., when energy prices go up faster than planned) and can clearly benefit directly from a higher-grade energy performance certificate and from improved livability of the campus facilities.

Remuneration The current contract and remuneration models do not provide incentives to the planners, architects, and craftsmen to provide high-energy and cost-efficient project structures, technologies, or methods of implementation. In some countries, as in Germany and the United States, architects earn greater financial compensation for designs that increase the building's complexity and total of investment costs; this relation between payment and investment costs is detrimental to the project's cost-effectiveness.

Strengths and Shortcomings Beyond that, this model has several serious shortcomings that lead to cost increases, cash-flow underperformance, and other serious problems:[1]

[1] Public investment projects have in average 35% of investment cost increasement during the design and implementation phase according to the Institute of Building Economics, University of Stuttgart, 2012.

- The feedback model is “open,” i.e., there is no feedback based on operational experience. This influences the quality of planning, construction, and operation.
- Decision-making is fixed to one key criterion, initial investment, which does not account for LCCs.
- Neither planners nor architects are required to provide follow-up or respond to questions related to energy performance or the investment costs.
- Although this model is commonly used, few reports on current research projects are available. An Annex 73 case study evaluation plainly shows that the typical division of the scope of work is between a design company, a contracting company, and, in a number of cases, a professional operator with the community owner in the role of supervisor. Financing often seems to occur as a combination of a smaller amount of equity and third-party financing (via bank loans). So far, the experience from implemented EMPs has not been collected, evaluated, or distilled into lessons learned. In other commercial or industrial settings, the business process would follow well-defined steps that would include a “feedback loop.” The building sector would benefit from adopting these steps. In the public sector, these steps are seldom followed.

Recommendation Although most community projects are obviously executed with this model, the selection of this business model seems to incorporate numerous performance risks that can lead to massive investment cost increases or disturbed cash flow. If a community decides to use this business model, it should either ensure that a flexible refinancing structure that can accommodate cost increases is available or, alternatively, consider a combination of strict project management and a stipulation that subcontracts penalize cost increases.

10.7.2 Fixed Payment Model and Utility Fixed Repayment Model

Funding The fixed payment model and utility repayment model, which are primarily used by commercial building owners, are **fixed repayment models** in which the upfront capital cost of an energy efficiency retrofit is organized, subsidized, and at times fully provided by either a utility or by a Property Assessment Clean Energy (PACE) program financing mechanism established by a city, county, or Port Authority in the United States and in a handful of European countries.

Remuneration These investments are repaid through monthly, fixed, non-performance-related surcharges. The “utility fixed repayment” version of this model requires a supportive policy framework to function; the types of legislative changes that regulators have may include: requirements for electric and gas utilities to improve their customers’ energy efficiency by a certain amount each year; the application of white certificate programs or the decoupling utility profits from the quantity of electricity sold; and requirements that utilities invest first in the lowest-cost sources of energy. Although the remuneration of the utility is not related to the actual performance of an implemented project, the **utility fixed repayment model** has several immediate advantages over the **appropriated funding model**:

1. Utility cost of finance, access to funds, and available leverage should be considerably better than that achieved by owners under **appropriated funding model**.
2. Friction costs (total direct and indirect costs associated with a financial transaction) are reduced from the economies of scale created by a utility executing many hundreds or thousands of its individual client retrofits.
3. Customer "ease of execution" is enhanced as execution is streamlined, and there is less work for the building's owner than in owner-financed model.
4. Government can use its relationship with the utility sector to align interests and push national energy efficiency targets down to the corporate level through the imposition of standards and market-based programs like "CERT" in the United Kingdom or the white certificate scheme in Italy.

Currently, countries in EU are encouraged by the European Commission to enter into this business scheme by using energy mortgage repayment models that have been developed recently.

Responsibilities PACE models often involve utilities that act as a general contractor in scope 1–4 for the building or community owner. As design, implementation, and, oftentimes, operation are in the hands of the utility, this model provides opportunities for "self-learning" systems in which design approaches that did not work out well in the operation or implementation phase can be adjusted and optimized.

Strengths and Shortcomings The "fixed" payment models provide up-scaling advantages (reduced specific investment costs), standardized design, implementation, and operation processes provided by the utility and some incentives for the service providers to stay on track with the predicted investment costs, energy savings performance, and cash-flow performance. The incentive for the service provider is to keep the costs (at least) at the same level as the fixed payments. The service provider has the same incentive to manage subcontracting parties in a much more professional and target-driven manner than could a public community manager. However, the performance component of the remuneration is not very strong, as it does not rely on the energy savings performance that is monitored at the energy meter, which in some cases may lead to differences between prediction and performance.

Recommendation The fixed or utility fixed models provide the full scope of services for communities; besides taking care of renewables and efficiency, setting up microgrids and energy systems is "normal business" for the service providers. The service provider often takes responsibility for the most critical aspects of a community project and has sufficient incentives to keep the costs and cash-flow performance under control.

10.7.3 Energy (Saving) Performance Contracting (ESPC) Model

Funding Third-party funding to implement EMPs can be obtained far more quickly than can government funds such as energy savings performance contracts (ESPC) or utility energy service contracts (UESC, 10.7.4). The ESPC standard contracts transfer energy and other LCC savings into investments over a contract phase of several years. With the ESCO providing the first investment, ESPC allows communities to implement their EMP project in one step by replacing or complementing public funding sources by ESCO funding. The appeal of ESPC is that the net present value (NPV) of the total project is greater than or equal to zero over the life of the contract. Legislatively allowed ceilings for ESPC durations (financing term) vary by state but are typically in the 15–25-year range. The US Federal Government caps the duration of an ESPC term at 25 years; in Germany's federal buildings, the ESPC terms are limited to 15 years, but upfront payments are allowed if the payback period is longer.

Responsibilities ESCOs began in the early 1990s–2000s as control system providers into the ESPC business. In recent years, ESCOs have been adapted to better meet user needs by allowing building renovation, microgrid, and energy storage to become part of the technical scope. ESCOs claim to provide a full-service approach in which the ESCO takes responsibility for all six scopes.

Remuneration The ESCO facilitates funding for the first investment, and the ESCO is repaid via energy and/or operational savings as described in Sect. 10.3. The savings are usually measured and verified using standardized processes, e.g., the USDOE standard,[2] the EWO-Schemes,[3] or other national schemes.

Strengths and Shortcomings Essentially, the utility and O&M budget is held constant (except for escalation) for the duration of the contract, and the energy savings derived from new infrastructure repay the loan. However, there are inherent obstacles in using these financing mechanisms:

- Primary stakeholders often distrust the ESPC or UESC financing vehicle, primarily because they do not fully understand it.
- Public sector processes for ESPC projects and M&V results often involve long approval cycles.

The M&V is a standardized but work-intensive process that requires expertise and capacities. Some specific elements to help make an ESPC or UESC economical are:

[2] https://www.energy.gov/eere/femp/measurement-and-verification-federal-energy-savings-performance-contracts

[3] https://evo-world.org/en/products-services-mainmenu-en/protocols/ipmvp

- CHP, which allows the substitution of power purchase with less costly CHP power
- O&M savings (see 10.2)
- Utility savings, e.g., optimize grid and off-grid, demand charge avoidance and peak shaving and curtailment programs
- Offsite sales
- Bundling with fast-payback ECMs (e.g., fixing steam or water leaks is usually very low cost but delivers a lot of savings that can then be used to subsidize a boiler with a 30-year payback or windows with a 50-year payback)
- Equipment-need avoidance, e.g., use of a CHP may obviate the need for planned individual building boilers

Recommendations The ESPC model has been used in a large number of community projects in Germany and the United States. The ESPC model is useful for communities with limited funding resources since the ESCO funds the first investment and is repaid through energy and other LCC savings. The limitation of ESPC is the balance between investment and LCC savings over the project's lifespan; this limitation can only be bridged by upfront payments by the user.

10.7.4 UESC

Funding Mechanism UESC and ESPC contracts are very similar, except that in a UESC the government agency contracts with the utility and the ESCO is a subcontractor to the utility. In a UESC, similar to an ESPC, all facility or campus improvements may be paid for with energy or other LCC savings.

Strengths and Shortcomings UESCs are specifically used on the US Federal Government level as a means to rapidly update facility or campus infrastructure. The government customer can contract with a local utility directly, which then retains an ESCO to perform the work. This saves the customer time and money associated with competing the contract to multiple ESCOs and pushes this responsibility to the utility. One recent trend in UESCs is that some US Government agencies require the ESCO to guarantee savings for the duration of the contract. This is not typical for UESC projects but is being explored by some US Federal agencies. In Europe, Federal agencies are not able to contract a utility directly without a procurement process so the UESC does not exist in EU countries. However, this way of initiating ESPC projects would help to accelerate the EU energy service market more quickly.

Recommendations Effectively implementing community projects in an UESC can be a straightforward process—award an ESPC or UESC and allow the ESCO to implement most or all of the EMP. The implementation may be done in phases, but better continuity can be achieved if a single entity does the work. This inherent synergy allows new technology and new visions to be readily integrated into the designs over time.

10.7.5 Blended Funding (Public and Private Combined Funding)

Funding Mechanism This financing model, which applies appropriated funding to ESPC projects as a one-time payment (attributed to cost avoidance), can improve the economics by reducing the total cost to be financed (Lohse and Zhivov 2019; Jungclaus et al. 2017). This model allows the project to include longer payback measures, thereby increasing the amount of energy savings, energy system resilience improvements, and infrastructure renewal that an ESPC would not be able to achieve without this one-time payment. In the United States for some government agencies like the DoD, this appropriated funding must be designated solely for energy-related projects before being used as supplementary ESPC funding. There is often a strong argument for applying funds designated for non-energy projects as a one-time payment for an ESPC project to drive greater value, but the legal limitations of combined funding models must be considered.

There are a number of ways to fund a resilience project in whole or in part with private financing. First, for both ESPC and UESC, the law allows agencies to combine appropriations with private financing and for UESCs to be fully funded by appropriations. This can be especially beneficial for a resilience project that may rely on the coordination of construction and interoperability in operation. Also, including all appropriations in a project will leverage the savings that the additional funding generates for the project. For example, new transformers save energy, just not enough to pay for themselves. If appropriations are needed to augment private financing to include transformers in a project, the savings they do generate can be leveraged to support the project rather than delivering the savings back to public funds or to the treasury.

To maximize the value of this business model, agencies need to both understand the opportunity of pursuing combined funding and be prepared to act when the timing is right. A solid energy master plan developed by an unbiased third party is the critical first step to understanding the opportunities that a site may offer and can inform the need for appropriated funding and potential ESPC projects over time. This energy master plan should be closely coordinated with an energy capital investment plan so the agency can be prepared to execute and fund energy-related projects appropriately as funding becomes available. Additionally, the energy master plan should remain flexible to pursue combined funding projects as energy-related funds become available. The alignment of the work being performed by the ESCO with the arrival of appropriated funding that could be applied to the ESPC is critical when evaluating the availability of those funds to the ESPC.

10.7.6 Combined Energy and Non-energy Projects with Participation of ESCOs

While a combined funding approach can deliver deeper savings on limited budgets, several barriers prevent broad implementation of this model for US Federal Government agencies. These limitations do not apply to other cases including state and city government projects. In Federal contracts, ESPCs can only be paid from the savings that are generated from work that is executed as part of the ESPC. When an installation receives appropriated funding for an SRM project, that project is supposed to be solicited based on the rules in the Federal Acquisition Regulation (FAR). This process can but does not currently consider the potential to combine an ESPC effort with the SRM "funding" that could be used for "related" (energy-related) projects. If there is no relationship between the ESPC projects and the "funded" project, the FAR would prevail, and the non-energy-related scope would need to be solicited separately from the ESPC efforts. In the combined funding model #1 illustrated by Fig. 10.7, the general contractor (GC) constructs the entire project, but the energy-related portion is implemented under a subcontract with ESCO. The GC has two managers (the government customer and the ESCO), but the government customer is ultimately in charge of the entire project.

Soliciting non-energy-related scope separately from the ESPC efforts would significantly complicate the project's efforts. From a logistical standpoint, having two or more contractors onsite, implementing closely intertwined scopes, adds significant complexity to project implementation. Client teams would need to coordinate

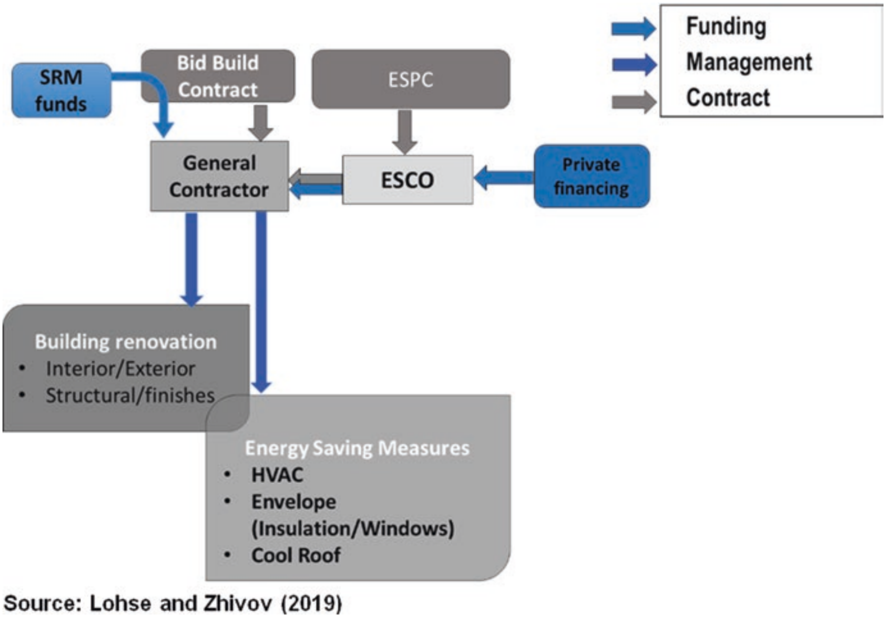

Fig. 10.7 Schematic of the combined funding model #1. (Source: Lohse and Zhivov 2019)

two contractors with different contracts, schedules, subcontractors, and scopes to work together in the same space, at the same time, without adversely impacting the project as a whole.

Potential contractor arrangements. There are many challenges associated with having separate contractors working on the respective energy and non-energy project scopes. This collaboration could take many forms. In one instance, an ESCO could serve as a subcontractor to a prime contractor delivering non-energy services as part of the SRM project. In this scenario, privacy of contract would prevent the agency from having any direct communication with the subcontractor; they would have to work through the prime contractor. Also, the agency's relationship with the prime contractor would likely be awarded as a construction contract or an operations and maintenance (O&M) contract, or as a service contract, which could include some construction effort. Those types of contracts would be subject to the FAR and can generally be in place for only 5 years. This would prevent the agency and the ESCO from benefitting from the partnership for a contract term of up to 25 years, which is necessary to deliver substantial energy savings as part of a DER. There are no regulations in place that can bridge this gap by enabling the agency to work with the subcontractor.

There are also challenges if the ESCO is the prime contractor and the agency is trying to incorporate the SRM project or project funding in with the ESCO work. In the combined funding model #2 illustrated by Fig. 10.8, the ESCO is awarded a design/build contract for non-energy-related building renovation and ESPC for energy-related measures. ESCO hires a GC but provides single point of contact for the government customer.

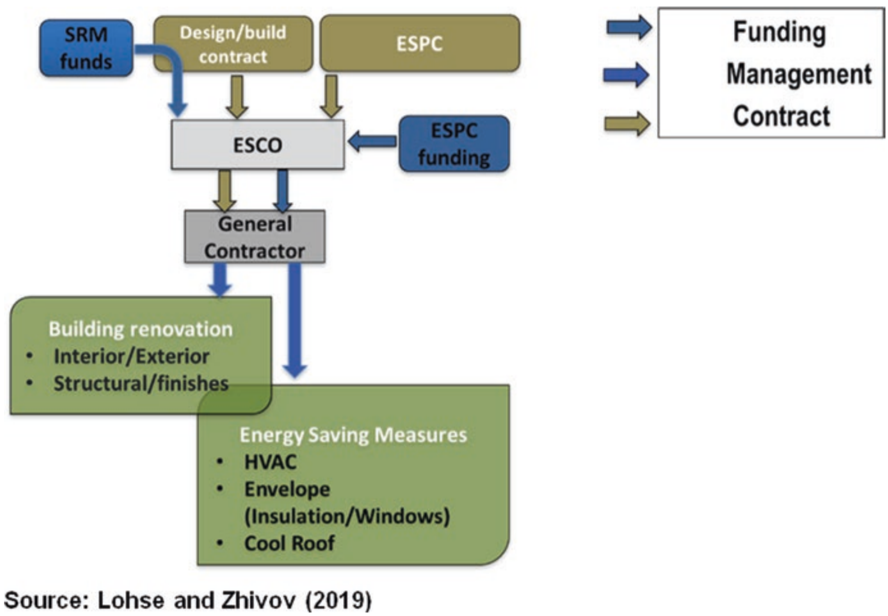

Fig. 10.8 Schematic of the combined funding model #2. (Source: Lohse and Zhivov 2019)

There has been ongoing discussion to evaluate methods that could be used where an ESCO is in place and has the potential to add value to SRM work. One potential option could be for the ESCO to provide equipment to a prime contractor as government furnished equipment. There are several challenges with how this could transpire, since the SRM contract assumes that the funding covers the entire project (including energy and non-energy scope). The ESCO and an SRM contractor would have to work out the specific arrangements that would allow for this to happen, thereby ensuring that neither contractor performs work outside of the scope of their respective contracts. There could also be challenges during the operation phase of the ESPC if the ESCO alleges that the provided equipment was damaged or not properly installed by the SRM contractor, and this is the reason that savings are not being realized. So, there are many challenges when separate contractors are hired to perform related energy and non-energy work on an SRM or similar project.

In summary, there are legal issues with how a contract can be structured to comply with 42 USC 8287 and not violate the FAR if appropriated funds are anticipated to be available at the time of contract award. There are privacy contract issues if the ESCO is a subcontractor to a prime contractor on an SRM project, which would inhibit the agency's ability to accept a comprehensive ESPC project from the prime. There are also issues with an ESCO performing work that is not energy work. Some limited non-energy work could be allowed, but substantial non-energy-related work performed by the ESCO or a subcontractor to the ESCO would not be allowed. So if there is a potential project that could achieve greater savings using the DER concept, it is critical that the team evaluating that project knows and understands the procurement rules and clearly delineates the energy and non-energy scopes to bring the greatest value to the ESPC project.

10.7.7 ESPC Energy Sales Agreements

ESPC energy sales agreements (ESAs) use the ESPC authority to implement distributed energy projects on federal buildings or land. ESAs are implemented as an ECM within an ESPC. The ESA ECM is initially privately owned to potentially qualify for tax incentives. The federal agency purchases the electricity it produces with guaranteed cost savings in the form of a lower electric rate than currently paid to the electric utility. The ESCO owns, operates, and maintains the ECM, and any tax incentives (e.g., investment tax credits, accelerated depreciation, state/local incentives), RECs, or other incentives can be applied by the ESCO to reduce the ESA ECM price to benefit the agency. The major advantage that ESPC ESAs have over PPAs is that an ESA ECM could be one or more components of a microgrid that is implemented in a comprehensive ESPC project to contribute to resilience needs.

10.7.8 Power Purchase Agreements

DoD's 30-year authority (10 U.S.C. § 2922a) can be used for power purchase agreements (PPAs) at DoD sites to implement onsite distributed energy projects with no or minimal upfront capital costs. As explained in the FEMP whitepaper *Financing Microgrids in the Federal Sector*,[4] in a PPA the developer finances and installs the equipment, and the agency buys the power at a cents/kWh rate, based on a competitive procurement. The PPA may or may not include a minimum power purchase provision in the contract. The developer owns the equipment, assumes performance risk, and provides O&M, repair, and equipment replacement for the term of the contract. A PPA most likely will not be able to fund a comprehensive microgrid, but it could be used to finance a component such as a large PV system, which could be incorporated into a microgrid system.

If a PPA were previously used to implement distributed energy project prior to a resilience planning effort, that contractual arrangement may not allow those DERs to be included in the microgrid. The agency will have to obtain permission from the PPA provider/DER owner to include the asset in the microgrid, likely requiring renegotiation of contract terms and pricing if the owner agrees.

10.7.9 Enhanced Use Lease (EUL)

An EUL is used in many ESPC- and other ESCO-based contracts in the EU and the United States. In EU countries, CHP power production is considered to be the residual power reserve in case the renewable power production is not sufficient. The feed-in power in the high-voltage grid is subsidized to provide incentives for ESCOs to set up detached CHP stations between 1 and 50 MWel (3 and 171 MMBtu/hr).

In the United States, EUL are used by DoD installations that have underutilized land that is offered to a third-party developer (e.g., a utility, ESCO, or other power plant developer/operator) for lease to build a power plant. This power plant will be built on the land and the power sold to the grid. The developer is responsible for all development (engineering, operation, financing, etc.) of the power plant. In exchange for a long-term lease (30–40 years), the customer receives (1) the power from the power plant built on their land should the grid fail and (2) "in kind consideration" (IKC) for the land. IKC can take the form of cash payment but more often involves needed infrastructure upgrades at the installation or facility (substation work to accept the power during a utility outage, advanced power controls, etc.). All financial concerns fall on the developer—selling the power, paying back loans, etc. The customer receives needed resiliency with no cash outlay. The main drawback to the customer is that the leased land is not available for use (expansion) for 30–40

[4] https://www.energy.gov/sites/prod/files/2020/08/f77/financing-microgrids.pdf

years. Use of EUL for energy system resilience enhancement can be illustrated by the following example described in Yamanaka (2020).

The Army Office of Energy Initiatives (OEI), US Army Garrison-Hawaii (USAG-HI), and Hawaiian Electric Company (HECO) developed the 50 MW Schofield Generating Station (SGS) to provide grid stability and to increase resilience for the Army and island of Oahu. The Army provided HECO a 35-year lease for 3 ha (8 acres) for SGS. In lieu of lease rent payment, HECO modified their existing 46 kV infrastructure to create a Schofield microgrid that enables SGS to provide dedicated power within 2 hours of an Army request for Schofield Barracks, Wheeler Army Airfield, Field Station Kunia, and South Range. SGS consists of six 8.3 MW, quick-start reciprocating internal combustion engines that operate on diesel or biodiesel (Fig. 10.9). This configuration provides the flexibility needed to mitigate Oahu's renewable variability and increase the amount of solar and wind on the HECO system. It also meets the Army's power and resilience requirements. Since the Schofield microgrid requires only four of the units to meet all power needs, two units are redundant, which further increases resilience. Over 5 days of fuel is always stored on site with enough storage capacity to store 13 days of fuel.

The lease requires 3 million gallons of biodiesel be used annually to contribute to Federal renewable goals. To provide additional flexibility, the Army will perform annual reviews to ensure that the biofuel requirement remains mutually beneficial and cost-effective throughout the term of the lease.

Because SGS provides power to all HECO customers during normal conditions, it is a rate-based asset and paid for by all HECO customers. HECO finances, constructs, owns, operates, and maintains the SGS and the microgrid infrastructure. The Army continues to purchase power through existing contracts with no premium charge when microgrid services are used.

As the only power generation facility on Oahu located above the tsunami strike zone, this plant will dramatically improve the resiliency of the entire island grid network. It can also black-start other plants in the event of island wide blackout to improve restoration to benefit the entire community beyond the military.

According to HECO, this project represents about $167 million in capital investment and approximately 315 jobs during construction and 10 during operations.

Fig. 10.9 50 MW HECO Schofield Generating Station located on Schofield Barracks, HI

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