Chapter 2
Electric Energy Storage System

2.1 Requirements for an EES System

2.1.1 Development of the EES Use in the Power System

Electrical energy storage has been used in powers system since the beginning.

The first power systems were constructed as DC systems and are generally associated with the name Thomas Edison, who founded the General Electric Edison Company in the United States in the late 1880s. The first electric city light was supplied by electricity from a DC generator combined with battery storage. The first large power station used the energy of falling water and converted it into AC electricity [1]. The energy storages (batteries) at that time were a necessary part of the power system and extended the limited supply of power from generators in the night, operating those generators in parallel with batteries that had been charged during the day.

Many local energy storages (batteries) were also used later (e.g., in Germany in the 1930, see also Table 2.1) to stabilize and support the power system, especially during the night. Energy storage comprised about 2 % of the installed power (7 GW) at that time.

The tasks of energy storages in the advance power systems of the twentieth century have changed. The construction of large power stations and reliable meshed high-voltage power systems led to the decrease of energy production costs (also see Fig. 2.1). Therefore, local energy storages have lost their economic advantage and have been decommissioned. Nevertheless, electric storage systems, in this case hydroelectric power storages, continue to be used in the power systems for two main reasons: their very fast power reserve and peak-power supply units.

Other grid services are covered in the modern power system directly by generation power units (e.g., spinning reserve) and local operation issues (e.g., voltage control).

A revival of local storage, particularly batteries, occurred at the end of the twentieth century as a result of the regulatory boundaries of the time. Several special applications of local storages were constructed and operated with economic benefits (see Table 2.2). But, the changes in the supply structure due to the visible growth of

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Table 2.1 BES systems in German cities (1930) [2, 3]

Location	Battery power in MW	
	2 h discharge	20 min discharge
Berlin	66.5	186.0
Hamburg	17.3	49.0
München	11.0	31.0
Leipzig	10.2	29.0
Stuttgart	6.4	18.0
Bremen	4.9	13.9

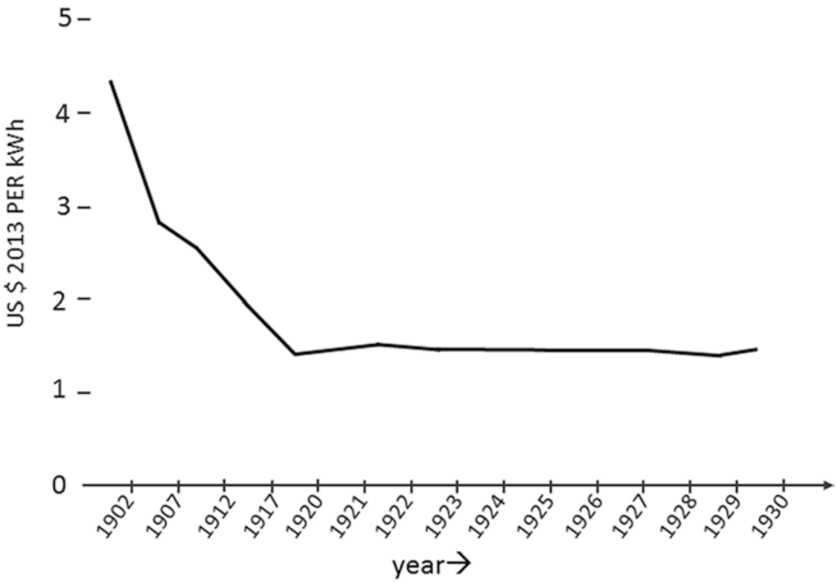

Fig. 2.1 Average price for electric energy 1902–1930 (in US$ 2013) [4, 5]

renewable generation in the twenty-first century made it necessary to revise the role of EES in the power system.

Considering the structure of the generation mix today in counties like Denmark or Germany, a portion of the renewable energy produced is often wasted, normally due to forecasting errors.[1] The transmission system operator 50 Hz Transmission in the northeast of Germany spent more than 1 billion Euros in 2015 on rescheduling measures [6] resulting from the forecast error. This tendency will continue if 80 % renewable generation is reached in the 50 Hz operating area. Today, the renewable generation in this zone makes up about 40 %. Collecting this wasted renewable energy for later use as reserve power is a new option for EES. Also, delivery of other system services, especially at the distribution level (see also the next chapters), make EES one of the most important flexibility options for smart grids throughout the world today.

[1] The mean value of the forecasting error of renewable generation is estimated at about 2.5 % over for 24 h. The real error could be much higher.

Table 2.2 Battery energy storage systems in operation at the end of the twentieth century (planned and in operation) [3, 4][2]

Company/Location	Power/Capacity	Battery: producer and type	Converter: producer and type	Primary applications	Secondary applications	Date
Elektrizitätswerk Hammermuhle Selters, Germany	400 kW 400 kWh	Dr. Jungfer (Austria): flooded lead-acid	Benning: line commutated	Load Leveling		1980–2000
Southern California Edison Chino, CA/USA	10 MW 40 MWh	Exide: flooded lead-acid	GE: self- commutated GTO	Utility Energy Storage Demonstration, Load Leveling, Spinning Reserve	T&D Deferral, Frequency Regulation, Voltage Regulation	1988
Crescent Electric Member Coop. Statesville, NC/USA	500 kW 500 kWh	GNB: flooded lead-acid	-: line-commutated	Peak Shaving	Voltage Regulation	1987
Johnson Controls; Humbolt Foundry Milwaukee, WI/USA	300 kW 600 kWh	-: maintenance-free, gelled, lead-acid	-: dual-bridge, six-pulse, line-commutated	Peak Shaving		1989
Delco Remy, General Motors Muncie, IN	300 kW 600 kWh	-: heavy-duty, low-maintenance, lead-acid automotive batteries.	Omnion: six-pulse, line-commutated	Peak Shaving, Battery testing	Alternative automotive battery uses.	1987
BEWAG—AG Berlin, Federal Republic of Germany	17 MW 14 MWh	Hagen: flooded lead-acid (CSM technology)	AEG: 12-pulse, line-commutated	Frequency Regulation, Spinning Reserve		1986

Table 2.2 (continued)

Company/Location	Power/Capacity	Battery: producer and type	Converter: producer and type	Primary applications	Secondary applications	Date
Kansai Electric Power Company Tatsumi, Japan	1 MW 4 MWh	Japan Storage Battery: flooded lead-acid	Toshiba: 12-pulse, self-commutated, GTO	Multi-Purpose Demonstration, Load Leveling, Utility Application Testing	Frequency and Voltage Regulation, Active and Reactive Power Control, Spinning Reserve	1986
Hagen Batterie—AG Soest, Federal Republic of Germany	500 kW 7 MWh	Hagen: flooded lead-acid		Load Leveling		1986
Vaal Reefs Exploration and Mining Co. South Africa	4 MW 7.4 MWh	Hagen: flooded lead-acid (CSM technology)	AEG: six-pulse line-commutated	Peak Shaving/Emergency Power		1989
San Diego Gas and Electric San Diego, California	200 kW 400 kWh	Exide: valve-regulated lead-acid (VRLA) with gelled electrolyte.	Omnion: transistor-based, self-commutated	Customer Peak Shaving, Transit Peak Shaving, Load Leveling, Load following, Start-up, Spinning Reserve, T&D Deferral	Spinning Reserve, Voltage / Reactive Power Control, T&D Deferral	1992
Puerto Rico Electric Power Authority San Juan, Puerto Rico	20 MW 14 MWh	C&D: flooded lead-calcium grid	GE: 18-pulse, self-commutated, GTO	Frequency Control, Spinning Reserve, Frequency Regulation	Voltage Control	1993
Pacific Gas and Electric San Ramon, California	250 kW 167 kWh	Delco-Remy: maintenance-free, lead-acid batteries	Omnion: transistor-based, self-commutated	Distributed Peak Shaving		1993

Table 2.2 (continued)

Company/Location	Power/Capacity	Battery: producer and type	Converter: producer and type	Primary applications	Secondary applications	Date
Stadtwerke Herne AG, Herme, Germany	1200 kW 1200 kWh	HAGEN Batterie AG: flooded lead-acid batteries with negative copper grids,	Piller: self-commutated IGBT	Peak Load Shaving	Power Quality	1997
Bocholter Energie- und Wasserver-sorgung, Bocholt, Germany	1600 kW 1000 kWh	3 strings of 272 flooded lead-acid batteries with negative copper grids, OCSM type by HAGEN Batterie AG	Piller: self-commutated IGBT	Peak Load Shaving	Power Quality	1998
Pacific Gas and Electric Various Sites in Ca	500 kW 1 MWh	None specified	None specified	Distributed Peak Shaving, T&D Deferral		1994
Hawaii Electric Light Company Island of Hawaii (Big Island)	10 MW 15 MWh	GNB: valve-regulated lead-acid battery	GE: 18-pulse, self-commutated	Frequency Regulation, Spinning Reserve	Peak Shaving, Generation Deferral, Voltage Support, Load Leveling, Load Following	1994
Chugach Electric Association Anchorage, Alaska	20 MW 10 MWh	None specified	None specified	Load Leveling, Load Following, Start-Up, Reduced Load Shedding, T&D Deferral, Frequency Regulation, Spinning Reserve		1995

Table 2.2 (continued)

Company/Location	Power/Capacity	Battery: producer and type	Converter: producer and type	Primary applications	Secondary applications	Date
Golden Valley Electric Association Fairbanks, Alaska	70 MW 17 MWh			Frequency Regulation, Spinning Reserve		1995
Oglethorpe Power Corporation Atlanta, Georgia	2 MW 10 sec	-: valve-regulated lead-acid.	Six-pulse, self-commutated	Power Quality, Load Leveling, Generation Capacity, T&D Deferral, Value of Service or Cost of Outage	Generation Deferral, Spinning Reserve, Voltage Regulation, T&D Deferral, Power Factor Correction, Frequency Regulation, Emergency Power Supply, Load Following,	1995
Stadtwerke Karlsruhe GmbH	100 kW 100 kWh	EXIDE: flooded lead-acid cells	Gustav-Klein GmbH: self-commutated IGBT	Peak Load Shaving	Power Quality	2003
Stadtwerke Karlsruhe GmbH	100 kW 100 kWh	EXIDE: valve-regulated lead-acid	Gustav-Klein GmbH: self-commutated IGBT	Peak Load Shaving	Power Quality	2003

Current forecasts estimate that the global energy-storage market will have an annual installation of 6 GW in 2017 and over 40 GW by 2022 [7]— from an initial base of only 0.34 GW installed in 2012 and 2013. The battery market alone will increase up to about 73 % by 2020 [8]. Furthermore, Li-ion batteries are projected to occupy more than 67 % of the total market share by 2020. Li-ion batteries are used extensively in BES for the smart grid as they can be produced with high capacities. This battery type offers high operating voltages in comparison to other batteries, such as lead-acid batteries and sodium-sulfur batteries. Other benefits of Li-ion batteries include their light weight and compact size, which will augment their adoption into the energy storage system. All regions of the global market are forecast to increase Li-ion battery storage over the next 4 years. There will be a general increase of US$1.7 billion in the smart grid, battery and storage, and efficiency sectors. The Americas dominated the battery-storage market for the smart grid and accounted in 2013 for around 60 % of the total market share.

2.1.2 Requirements for EES and Extension of Storage Usability in the Smart Grid

Some new business cases for EES use can be beneficial when the generation mix is dominated by weather-dependent renewable generation.

The "white paper[2] of IEC [9]" summarizes these business cases for three groups, utilities, consumers and generators of renewable energy, as follows:

- from the point of view of utilities:
  - Time shifting: Reducing the generation costs by storing in the off-peak time (mainly at night) and discharging at peak time (mainly in the daytime or noon peak hours).
  - Power quality: EES can provide frequency control functionalities and, when located at the end of heavily loaded lines (especially in the distribution), may improve voltage drops by controlled charge/discharge operation.
  - Making more efficient use of the network: Time-limited congestions in a power network may occur when the transmission/distribution line cannot be reinforced. Large-scale EES (especially large-scale batteries) located in strategic places can mitigate the congestion and help to postpone and suspend reinforcement of the network.
  - In isolated grids: The operation of small, isolated power grids (e.g., islands or regions located far away) powered by diesel or renewable generation can be stabilized by EES.
  - Emergency power supply for protection and control equipment: Batteries can be used for this important emergency activity in case of outage.

[2] White paper – report which summarizes the advantages and disadvantages, costs, etc., of concrete solutions or technology.

- from the point of view of consumers:
  - Time-shifting/cost-saving aspect: Incentives for flattening the electricity load for consumers are given in the form of time-varying electricity prices. Reduction of peak power by using EES can also decrease the customers' connection costs.
  - Emergency power supply: EES can be used for the consumers' emergency power supply.
  - Electric vehicle and mobile applications: V2H (vehicle to home) or V2G (vehicle to grid) can also be used locally (charged with local PV generators) or globally (charge- and/or discharge-supporting network services).
- from the point of view of generators of renewable energy:
  - Time-shifting: Storing surplus electricity in EES and using it when necessary for ancillary services or selling to the network operator.
  - Effective connection to grid: EES can absorb fluctuations more effectively than other mitigation measures, e.g., a phase shifter.

One can see from this classification that some of the EES services can be used by various users for both similar and differing business cases—so a multiple usage is possible (e.g., time-shifting).

Furthermore, taking into account the grid services, the EES can provide the following kinds of mentioned services [10]:

- Bulk-energy services:
  - Electric energy time-shifting (arbitrage)
  - Electric-supply capacity
- Ancillary services:
  - Regulation
  - Spinning, not-spinning and supplemental reserves
  - Voltage support
  - Black start
- Transmission infrastructure services:
  - Transmission-upgrade deferral
  - Transmission-congestion relief
- Distribution infrastructure services:
  - Distribution-upgrade deferral
  - Voltage support
- Customer energy management services:
  - Power quality
  - Power reliability
  - Retail electric-energy time-shift
  - Demand-charge management

The EES can be generally characterized for planning and operating purposes by some specific parameters independent of the technologies used. The list of these parameters and short descriptions are given in Table 2.3.

The mean parameters requested from the EES are now given in Table 2.4, taking into account the various EES applications mentioned previously.

Table 2.3 Specific parameters of EES. General requirements

Parameters	Dimensions	Typical values	Description
Output power or power capacity	kW, MW	Distribution 10–100 kW Transmission Up to GW	The nominal power of the output way (e.g., transformer).
Storage capacity	h, also in kWh or MWh	Short-term Seconds to minutes Long-term hours to weeks	The length of time the nominal power could provide up to the limit of the charge depth. After this, it is still possible to extract the energy from the storage, but some damage is possible.
Depth of charge	% of capacity	Batteries 40 %—up to min 10 % Other EES 10 %	The minimal level of capacity which could be achieved without damage of storage by nominal charge/discharge process.
Charging ratio	% of the nominal power	Depends on technology, 10–100 %	The power rate at which the storage can be charged without damages. This generally depends on charge unit construction and technology. Most battery types are not linear and can be given as a voltage-dependent curve.
Discharge power ratio	% of the nominal power	Depends on technology, 100% and more	The amount of power which the storage can discharge without damages. This generally depends on discharge unit construction and technology. Most battery types are not linear and can be given as a voltage-dependent curve.
AC voltage requirements	V or kV	Depends on technology and power	Depends on power; the AC voltage must be complementary with connection requirements.
Duty cycle requirements	Cycle per life time	Depends on technology 1000 up to 10,000 cycles per lifetime	Depends on application; a different cycle number is necessary to reach economic benefits from EES, e.g., for 10 years' pay back and one day's full cycle, about 5000 cycles of storage is necessary.
Portability requirements	Optimal module size	Depends on technology 100 % and more	Especially for mobile or local storages; an optimal storage size should be standardized.

Table 2.3 (continued)

Parameters	Dimensions	Typical values	Description
State of charge (SOC)	In % of capacity	Depends on technology and time	Especially important for operation issued. The SOC can also be forecast and used for optimal storage operation.
Depth of discharge (DoD)	In % of capacity	Depends on technology	It is the ratio of the maximum amount of energy that could be discharged from an energy storage system to the maximum storable energy.
Self-discharge	Daily loss of energy in % of capacity	Depends on technology	Represents the losses of energy from such internal processes as endothermic reactions (in batteries), flow resistance in pumps (in flow batteries) or water evaporation (in pumped storage plants).
Energy density	kW/m³ or kW/liter	Depends on technology	It is the ratio of energy discharged to the energy storage system's total capacity.
Start-up time	s	Few second to minutes	It is the time required to deliver the power requested to a consumer.
Ramp-up time	s	Few second to minutes	It is the time needed to deliver the maximum power.
Specific costs	€/kW (power-specific costs) €/kWh (energy-specific costs)	Depends on technology: €/kW 300–2000 €/kWh 50–1000	Most reasonable parameter for usage of EES. Very strongly dependent on technology and application.

Table 2.4 Summary of technical requirements for applications [3]

Application	Storage (in min)	Power	AC voltage in kV	Duty cycle requirements	Floor space (importance)	Portability (importance)
Spinning reserve	10^{1}–10^{2}	10^{1}–10^{2} MW, LC	10^{1}–10^{2}	10^{1}/year, random, discharge only	Medium	Low
Area control & Frequency responsive reserve	Charge/ discharge Cycles of <10^{1}	10^{1}–10^{2} MW, LC	10^{1}–10^{2}	Random, continuous charge/discharge cycle clustered in 2-h blocks daily	Low	Low
Load levelling	10^{2}–$0.5*10^{3}$	10°–10^{2} MW, LC	10^{1}–$0.5*10^{3}$	10^{2}/year, regular, periodic, weekday block discharge, increased use in shoulder months	Medium	Negligible
Transmission system stability	10^{-3}–10^{-1}	10^{1}–10^{2} MVA, SC	10^{1}–$0.5*10^{3}$	10^{3}/year, random, charge & discharge cycles	Medium	Low
Transmission voltage regulation	10^{1}–10^{2}	10°–10^{1} MVAR, SC	10^{1}–10^{2}	10^{2}/year, random charge & discharge cycles typically weekdays, seasonal by region—at least 6–7 months	Medium	High
Transmission facility deferral	10^{2}	10^{-1}–10^{1} MVA, LC	10^{0}–10^{1}	10^{2}/year, most likely during weekday peak, charge & discharge	Medium	Medium
Distribution facility deferral	10^{2}	10^{-1}–10^{0} MW, LC	10^{0}–10^{1}	10^{2}/year, most likely during weekday peak, charge & discharge	Medium	Medium
Customer energy management	10^{1}–10^{2}	10^{-2}–10^{1} MVA, LC	10^{-1}–10^{1}	10^{2}–10^{3}/year, regular periods	High	Varies
Power quality & Reliability	10^{-3}–10^{0}	10^{-2}–10^{1} MVA, SC	10^{-1}–10^{1}	10^{2}–10^{3}/year, irregular periods, charge & discharge	High	Varies
Renewable energy management	10^{0}–10^{3}	10^{-2}–10^{2} MVA, LC	10^{-1}–10^{1}	10^{2}–10^{3}/year, regular periods, discharge only, unpredictable source	Varies	Varies

2.2 Generic Model of EES

2.2.1 *Standardizing Generic Model of EES*

The calculation and planning for power systems is divided into two types [11]:

- static calculation and planning, and
- dynamic calculation and planning.

A time scale is not used for the static calculations. Here only the maximal demand is used for dimensioning the electrical equipment and energy in order to balance the energy production during 1 h or one day (24 h).

EES models with different accuracy are necessary to provide calculations in the planning process of the power system. The chosen EES models for this calculation should match the accuracy and details corresponding to the mean models of the power system equipment, for example, generators and transformers.

Dynamic models of electric equipment are necessary for dynamic calculation; these models mostly described the features of objects by partial differential equations [12]. More adequate EES models based on, e.g., equivalent networks [13, 14], are sometimes required for the detailed planning of EES (e.g., dimensioning the inverter). The EES models for dynamic calculations will be not discussed in this book because they have been presented in more detail in other publications (also see Table 2.4). Depending on the calculation timescale, the models can also be simplified, and, if the calculation incorporates a very short time (e.g., less than a second), constant behavior of the equipment model of the EES model can be assumed in a critical situation.

Measurement data and physical characteristics of the devices are used for parameterization of models described mathematically. The accuracy of the models should be further adapted in order to provide extensive simulations of large networks in such a way that the main parameters and characteristics of single devices (here also EES) are considered without needlessly increasing the computing time.

Concerning the general requirements of the modeling, the EES can be integrated into the calculation in the power system as a combined generation/load device. The generation devices (generators) must be fully considered in such a model if the storage system is equipped with one such unit. This is the case if the pump hydro-energy storages (PHES), flywheels or CAES storages are used. In the case of electrochemical storages—when no rotating mass is in use during the conversion—only the performances of electrochemical processes and inverter properties must be considered in the model.

The generic structure of an EES model should have at least three surfaces to fulfill the requirements previously mentioned (see the following Fig. 2.2). The first, the main surface, consists of the physical model that is mainly described by the mathematical description and comprises the central point of the EES model. This *Ph*ysical *S*urface (PhS) of the model is then merged into its particular surrounding

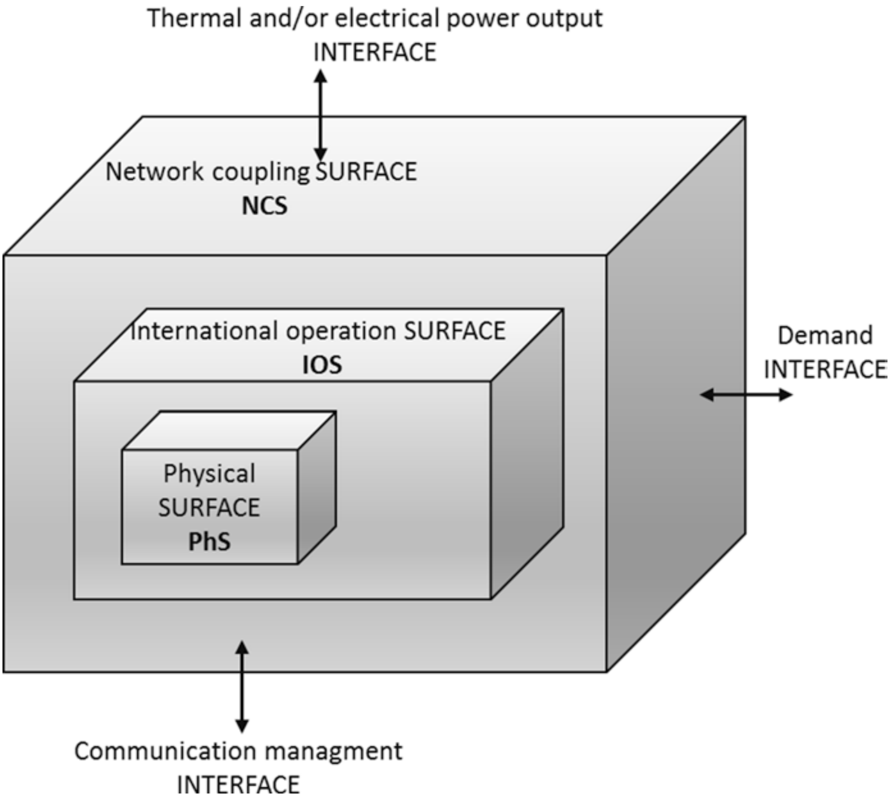

Fig. 2.2 Generalized surface and interface structure (SIS) of the EES units modeled

conditions, such as the thermal and electrical demand of the load, and new interfaces and demands on the model structure are introduced, particularly considering the emulation of the control systems. Table 2.5 summarizes the modeling requirements for the PhS of EES considering various types of storages and kinds of model implementation.

Table 2.5 Modeling the physical surface of EES for power-network planning

Model specification	Storage type	Model used
Static models for planning issues/long-term simulation	Common generic model independent of storage type	Reservoir model Parameterized depending on storage type
Dynamic models for simulation issues/short-term simulation in time domain	PHS, CAES, flywheels Batteries Storage medium H_2	Advance AC generator model [x1], e.g., equivalent networks or torsion model [x2] Equivalent networks model or inverter model [x3] Inverter advance model [x4]

The PhS together with the emulated surrounding systems create the second platform—the *I*nternal *O*peration *S*urface (IOS) of the EES unit. The third model surface, the *N*etwork *C*oupling *S*urface (NCS) of the unit, realized mainly as a simplified inverter model together with the linking transformer, completes the structure of the EES unit model for the long-term interval simulations. The NCS surface has thee interfaces:

- thermal and electrical output,
- demand and
- communication management.

The energy supply of the EES and exchange between the EES and the power system is realized using the thermal and electrical output. This interface must also be rated respective to PhS parameters (e.g., nominal power).

The demand interface determines the output power requested and the communication management interface makes possible optimal control of the EES operation.

The model mentioned above corresponds well with the more general architecture of the power system given in the common information model (CIM) standard (also see Fig. 2.3). Using the CIM, the same kind of standard description can be used for different devices (e.g., storage, transmission and distribution devices) and also for various areas of implementation (e.g., market, optimal system operation). Thanks to standardizing the CIM description, it is easy to build the whole

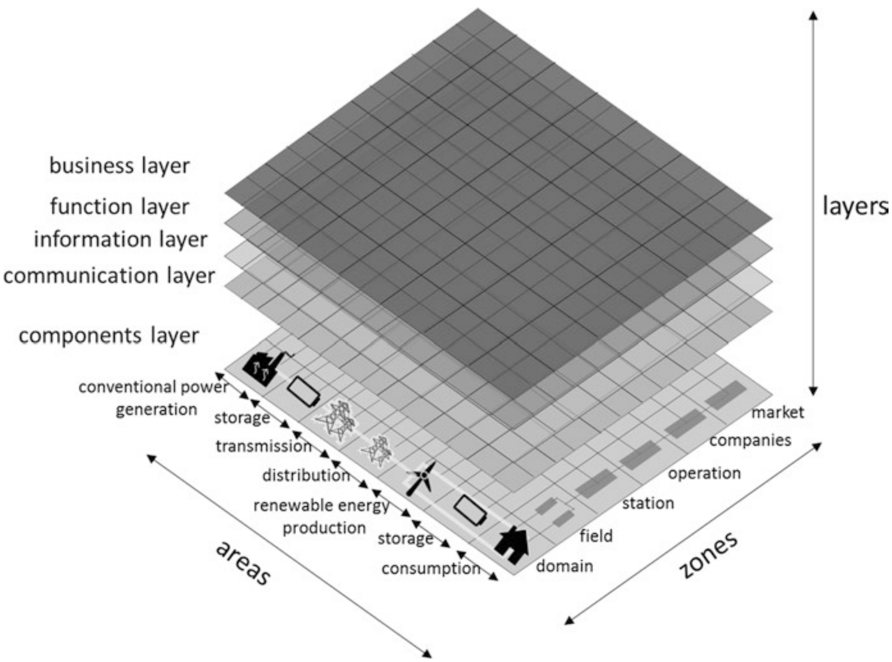

Fig. 2.3 The architectural structure of power system elements in comparison with standards [15]

model of the particular power system from the physical, as well from the ICT, point of view.

There are five surfaces (levels) in the CIM model presented here. The base level is the Component Level (surface). In addition to the general 3-SiS model of storage, the functionality and business levels are present in the CIM general model.

The consideration of different applications of EES is possible—in a systematic way—in the form of use cases. A use case describes the actors, relationships between them and information flow within each particular application. Use case blocks are identified and presented for storage tree usage in Fig. 2.4.

The use cases mentioned in Fig. 2.4 can be described as follows:

Economic Use of EES

Description

The EES supports the integration of RES into the power system. Using EES, the RES integration can be optimized and made profitable for all market participants. The market players here are the RES, EES, owners of EES and RES, direct sellers, energy market, power system operators and the local power system.

Own Consumption Operation Mode

Description

Stationary EES can buffer the electric energy produced by the RES. The dedicated use of EES close to small RES generation (e.g., PV on the roof of buildings) minimizes the transported power and increases the rate of self-supply, which is connected with economic benefits. The market players here are the EES, owners of the EES, consumers, power system operators, the local power system and local energy management systems (EMS).

Network Serviceable Operation

Description

Stationary EES can react to different events during the power system operation. Thus, EES can buffer the energy and, at other times, inject energy into the system.

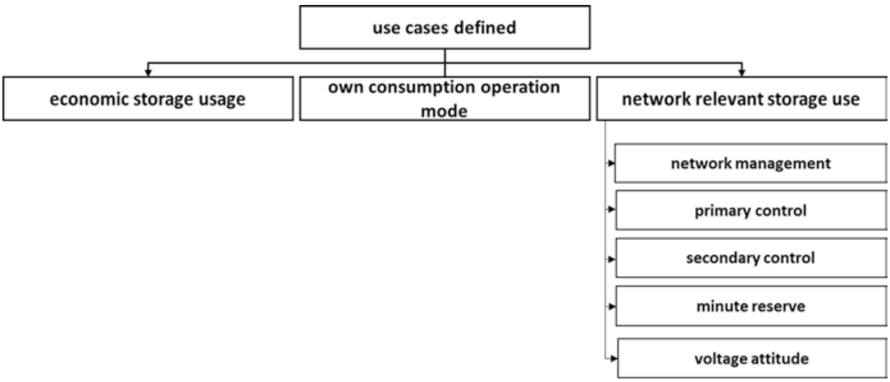

Fig. 2.4 Use cases defined for EES

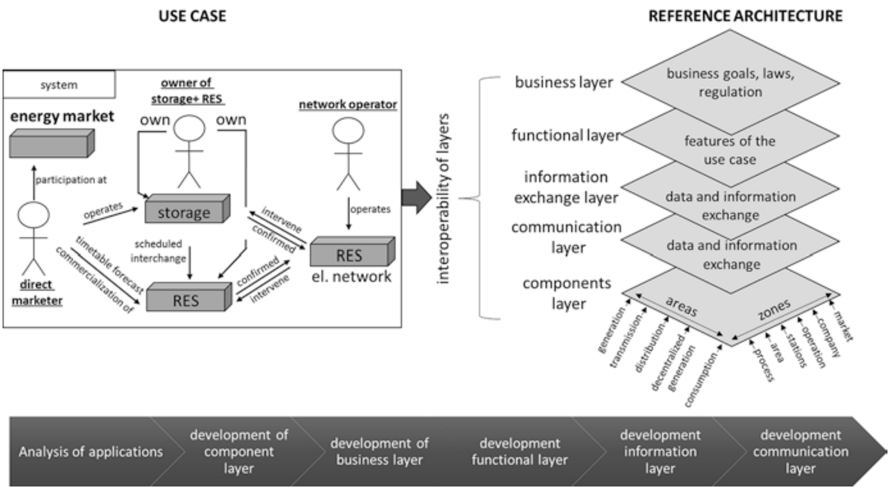

Fig. 2.5 Use case—own use of EES—description in CIM

The use of EES in this use case is possible in the critical areas, improving the supply security of the system and delivery of power system services.

The market players here are the EES, operators of the VPP (virtual power plant), power system operators, power system network, EMS and the consumers. Considering the EES in the context of the whole power system is important, and observing the system from the point of view of its components is very useful (also see Fig. 2.6)

A presentation in CIM enables one to describe the use cases concerning the EES and other elements of the power system in a standardized way. This is given as an example in Fig. 2.5.

Three active actors are involved in the process examined in this example, namely: the owner of the storage and RES, the system operator and the market agent. They each have different relationships to the objects (e.g., market, power network) and use storage in specific ways (e.g., hold, share).

Taking this architecture into account, all the use cases can be described structurally and, in this case, also modeled in the same standard manner.

The components interface is the backbone of the reference architecture and includes the equipment, applications, people and organizations involved in use cases. In this way, it is possible that a single component, particularly addressed by the use case, defines the participants and allocation to different domains and zones. Thereby, a single component is assigned to a concrete hierarchical zone and influences that area of the electric energy conversion (also see Fig. 2.6).

Finally, the business level of the model can help to decide the implementation of storage into the power system. This level includes different business processes, services and the organization of the electricity market that are each connected to the specific use case. The organization goals as well as the economic and regulation issues must be strongly considered here.

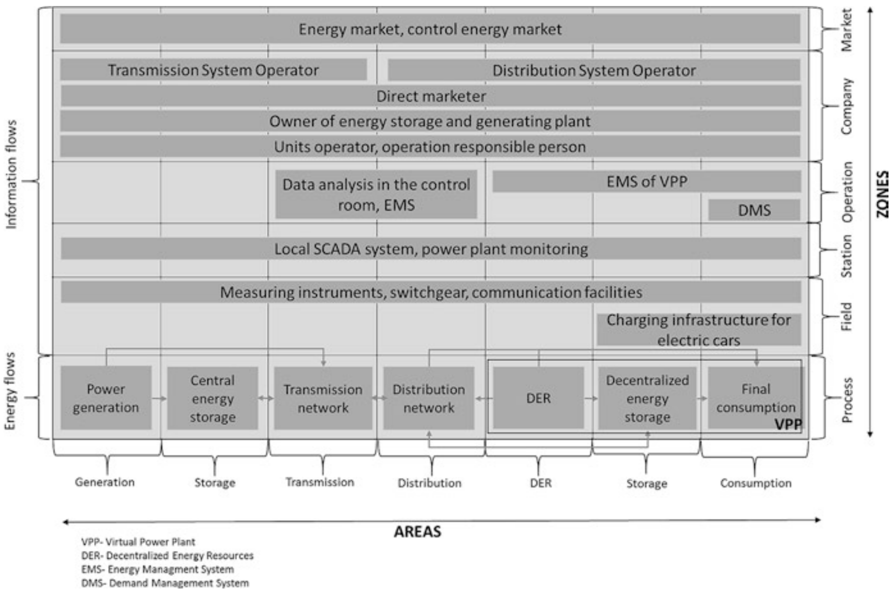

Fig. 2.6 Overview of the components of the power system

The functionality level is comprised of the function of each component and its relationships corresponding to the domain and zone. A particular function can be extracted from functionality. A sub-use case could be constructed from more specific use cases.

The information level consists of data which will be used or extended by various components by the activation of specific functions. The information sets that are exchanged are deducted from use cases in the form of sequence diagrams. The fundamental canonic data models were assigned using the analysis of available standards and show if there are any additional obligations or boundaries in its description.

Figure 2.7 presents the overview of the information level for the use case "economic use of energy storage". This information schema follows the schedule given below:

(1) At the beginning of each month, the EES and RES operator make a decision about the market-oriented energy delivery so that it will not be paid in the form of the feed-in tariff corresponding to the EEG 2014 §20 (1).
(2) In the next step, the RES owner/operator must decide if he prefers his own direct commercialization or the commercialization of the professional group. The latter should be preferred, especially for small RES units.
(3) Finally, the sell/buy order is placed on the spot market.
(4) After evaluation of the trade conditions, the market player is informed about the setting of his order.
(5) The finalized contract is framed (ECC Lux).
(6) After successful framing the scheduled ECC Lux, the resulting energy is planned by the responsible TSO. The TSO confirms, in an ideal case, the schedule with a final confirmation report. Thus, the delivery of the energy can follow.

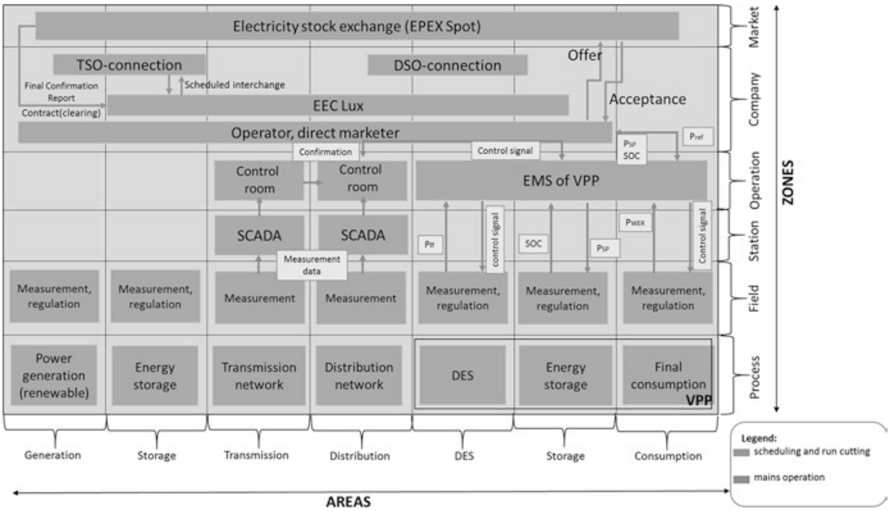

Fig. 2.7 Information level (surface): economic use case of EES

The focus of the communication surface for the practical realization of the contract mentioned above is the descriptions of protocols, interfaces and mechanisms for the interoperable information exchange between players in the defined use case. As mentioned before, the corresponding issues could be identified based on the data and canonic data model and are presented in Fig. 2.8. The VPP, its functionality and the role of EES usage in the future power system are pointed out in both the information and communication. The EES is a fixed part of the VPP concept and, in this case, the use of storages in the power system is indispensable.

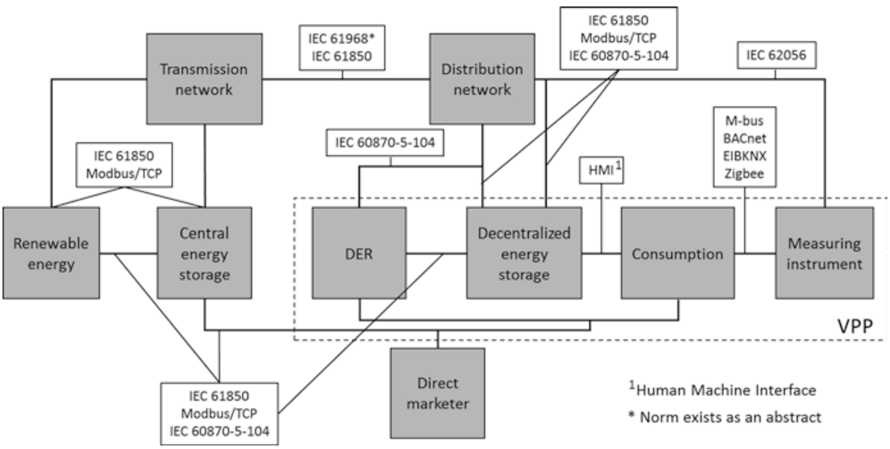

Fig. 2.8 Communication level for the economic use case of EES

The communication protocol used for the ICT connection in the future power system is also increasingly being standardized according to IEC standards. The protocol IEC 61850, which was developed especially for smart grid needs, has become particularly popular [16].

2.2.2 Physical Surface of the EES Model. Mathematical Generic Model

If the storage use is to be explicitly prepared, the EES should be modeled during the power system planning process. Such a standardized model can be based on the fundamental reservoir model, or it can be represented as a set of equations with linear or non-linear elements.

Because a long time scale is required for the planning process, the nominal power and the energy balance should be calculated for a specific time period, for example, 1 h or one day (24 h). These calculations result from the demand and use case as well as the charge and discharge processes in this time period [17]. These processes can cause losses that are connected with the energy conversions from electric energy to storage medium, EES and vice versa ESE, respectively, and also self-discharge if the storage is not in use, Elos. The whole loss of energy El in a time period T is given by Eq. (2.1):

$$E_l = E_{los} + E_{ES} + E_{SE} \tag{2.1}$$

The integral mathematical equation with restriction describes the storage energy E and can be formulated as:

$$E(t) = \int_0^{\Delta T} P_{in}(t)u(t)dt - \int_0^{\Delta T} P_{out}(t)v(t)dt \tag{2.2}$$

where:

$$u(t) = \begin{cases} 0 - \text{no charging time} \\ 1 - \text{charging time} \end{cases} \tag{2.2a}$$

$$v(t) = \begin{cases} 0 - \text{no discharging time} \\ 1 - \text{discharging time} \end{cases} \tag{2.2b}$$

The restrictions concerning the storage operation are given by (2.3a) and (2.3b).

$$u(t) \wedge v(t) \neq 1 \tag{2.3a}$$

$$E(t) \geq E_{min} \quad \wedge \quad E(t) \leq E_{max} \tag{2.3b}$$

where Emin and Emax are the possible maximum and minimum energy storage capacity, respectively.

The restrictions in the general storage model are specific for particular storages. The kind of storage is also hidden in the functions f_1 and f_2 which describe the charge/discharge processes [18]:

$$P_{in}(t) = f_1(E(t), E_{max}, E_{min}, z) \tag{2.4}$$

$$P_{out}(t) = f_2(E(t), E_{max}, E_{min}, z) \tag{2.5}$$

where z is the type of energy storage equipment.

Until now, only batteries have been used as local storage on an industrial scale (see Table 2.2). For this reason, the parameterization of the generic model was carried out exemplarily for a battery-energy-storage (BES) system (see also Sect. 2.3.3). The BES consists of three major subsystems: battery cells/stacks, power converters and balance of plant (known also as battery management system). The batteries are connected to the electric utility through a power converter, which rectifies AC to charge the batteries and later converts the DC back to AC to supply the utility load. The battery subsystem is sized to satisfy the energy (kWh) required by the customer for various functionalities, for example, a shaving the peak load to the necessary limitation. By contrast, the power converter subsystem is sized to satisfy the peak-power requirement (kW) of the load, which corresponds to the peak discharge rate of the battery (also see Fig. 2.9).

The parameterization of the models has been done exemplarily using the 30 kW/61 kWh lead-acid test BES installed by the BEWAG power utility in Berlin [18]. Three battery models were investigated in this test: the integrated reservoir model, network voltage model and fourth-order dynamic model. The test results showed that it is possible to determine the parameters for the three battery models using the same extensive test measurements.

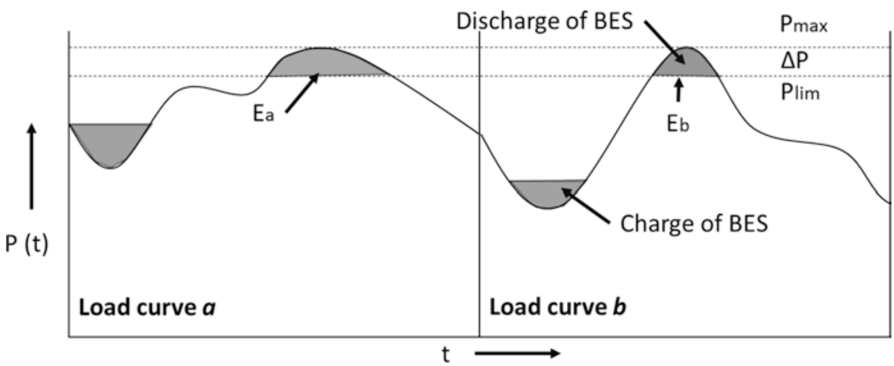

Fig. 2.9 Dependence of storage size upon the load profile E_a and E_b and the storage capacity in kWh by the load curve *a* or *b*, respectively

The integration reservoir model shows satisfactory exactness when the battery is discharged up to about 40 % of its capacity. By discharging the battery beyond this limit, an error of up to 20 % in the energy balance over a 24 h period between model calculations and measurements was observed. This error depends on the dynamics and intensity of charge/discharge cycles. The network-voltage model and dynamic model with partial optimization of parameters show an accuracy of about 98 % for the 24 h energy-exchange period. All of the models can be applied for calculating the optimal BES size, but generally, the integration reservoir model only meets the accuracy requirements for the planning of power-system expansion using slow charge/discharge processes.

2.3 EES in the Transmission and Distribution System

2.3.1 Factors Influencing the Value of Storage in Transmission Networks

From the general specifications given in Sect. 2.1.2, many storage application fields and benefits can be applied to the transmission system.

Pump-hydro energy storage (PHES) is characterized by high capacity (up to 10 h) and high installed power (up to 3 GW), and is traditionally used for improving the dynamic behavior of the power system (e.g., primary and secondary reserve [19]) and for providing some additional system services (e.g., black-start capability [20]). Currently, due to the high infeed of renewable energy, some new functionalities of PHES and other high capacity storage, such as CEAS, can be used. The following services may also be provided by energy storage systems in transmission networks:

- Investment deferral: New transmission lines add incremental capacity, whereas storage can be added at smaller ratings. A storage solution can, therefore, be advantageous.
- Loss reduction: The value of the storage systems arises from the reduced costs associated with losses and the improved environmental performance of networks.
- The value of the storage system in congested networks arises from the difference between the prices in the two zones, as well as from the potentially improved utilization of generation capacities.

These “new” storage applications have some limitations:

- Conflicts with “must-run” generation: The optimal operation of storage devices can conflict with the operation of base-load generators. A key point for minimizing this conflict appears to be the flexibility of the rest of the system.
- An excessively high storage capacity, which is required by some transmission implementation (e.g., investments deferral can sometimes require more hours of storage for only a few events per year, especially in winter), reduces its utilization factor.

Furthermore, some specific considerations must be taken into account for the installation of storage systems in transmission networks. Generally, each transmission network has unique characteristics. Before incorporating storage systems into a specific network, analysis of the targeted power system is necessary. Some characteristic issues, depending on the case, encourage the installation of storage systems (e.g., technical advantages), while others (e.g., economic benefits) discourage them. The specific characteristics of transmission networks mentioned before could be of a technical, geographical or economical nature and can be generally summarized as follows:

- Technical: Improving power flow, stabilizing system voltage, improving system stability (e.g., by delivery of reactive power), improving fault current capacity.
- Geographical: Interconnected power system, isolated power system.
- Economical: Comparisons in ratings, size and weight, capital and operating cost, life efficiency, per cycle cost.

Testing a variety of locations and technology types for the storage system installation can help to find the best solution.

It is useful if a storage–system generally satisfies one of following conditions:

- Loading rate of transmission lines is high and can be leveled by the use of storage

or

- system voltage is below standard voltage levels and can be improved by storage.

Additionally, conditions for the expected fault current and system stability before and after installation of the storage need to be checked in detail.

Next, geographical conditions should be considered when installing storage systems in interconnected systems or isolated systems. The installation of storage systems must satisfy the following conditions:

- Interconnected power system: location of the storage in a high-price zone compared to other areas;
- Isolated power system: only one source exists (storage assumes the reserve functionality) or not enough power is available for peak demand.

Finally, comparisons between economic considerations should be performed. These considerations should record ratings, size and weight, capital cost, life efficiency and per cycle cost.

2.3.2 EES in the Distribution System

The distribution system is the part of the power system in which the most changes have occurred in recent years. Clearly, most of those changes were caused by the massive development of renewable and decentralized generation. The distribution system has changed from a passive one, in which the energy flow was only top down, to an active one and, furthermore, has undergone a transformation in character to smart distribution. This means that the ICT are integrated into the coordination of the operation (and also distribution). This step was a big innovation in the power-system operation philosophy, but was necessary because part of the duty of system services must be coordinated increasingly between DSO and TSO and will migrate to smart distribution in the future [16].

The distribution system is fed by very highly distributed generation—for example, in Germany in 2016, there is about 60 GW (theoretically about 80 % of peak demand) generated mostly by wind and PV. These changes in the supply configuration lead to rule changes in the electrical market.

Considering the paradigm shift just mentioned, the use of storage in distribution has a particularly important position today and will continue to be important in the future. Some of the main functions of storage in distribution have already been mentioned, and the market position of EES is briefly described in Sect. 2.1. The most important services of EES in smart distribution can be summarized as follows:

- Distribution infrastructure services:
  - Distribution upgrade deferral
  - Voltage support
- Customer energy-management services:
  - Power quality
  - Power reliability
  - Retail electric energy time-shift
  - Demand charge management

These functionalities can be extended by other means, e.g., local domestic storage, storage integrated in e-cars or storage used in VPP (also see Sect. 2.1.2), the implementation of which will be realized within the next few years. In order to meet the goals of the generation mix for Germany and other countries in 2050, distributed storage (mostly advanced batteries) and long-term storage (mostly using H_2 as the storage medium) will be necessary for both a stable and affordable power system. (See Sect. 1.1 for more details on the future goals for generation mix.)

2.3.3 Example of Modeling and Implementation of the Models in the Planning and Simulation in Distribution

Independent of the fact that some storage technologies are already technically ripe, the use of storage in the power system is still coupled with high or very high expenses. Therefore, it is necessary to combine various functionalities to reach real economic benefit. In this chapter, five methodical examples will be given to illustrate the advanced procedures that can lead to wide storage implementation in distribution.

A: Optimal Storage Dimensioning in Smart Distribution

The most important economic benefit of EES can be shown by the peak-load-shaving operation mode. In this case, the benefits can come from both the price of power in energy tariffs and also from a delay of necessary network investment in the case of overloading equipment, e.g., lines or transformers.

The cost of the storage and corresponding benefits are dependent on the power and energy of optimal storage. In a storage model, load growth changes during the planning period and pricing data are necessary to determine the EES module using the daily load curve in the specific network.

One possibility is the use of an iterative search process for the computation of optimal storage for a particular load profile. The load profile is characterized by a relatively flat curve with one or two maxima. An example of a load profile is introduced in Fig. 2.9. Furthermore, how the use of storage allowed the shaving of the peak demand of ΔP power is also shown in Fig. 2.9. On the one hand (i.e., load curve a), a reasonable energy (time) is necessary for shaving the peak on this load curve. On the other hand, this is not the case in load curve b, when effectively less energy in the storage is required for the same ΔP peak shaving. If ΔP increases, taking into account the specific of the load curve, the necessary storage energy will also increase, but not proportionally.

Shifting energy costs needs to be considered, so it is necessary to know the energy price difference between on and off peak times. The various benefits resulting from those prices must balance the storage costs, which are calculated using the specific cost of power and energy (also see Table 2.4).

The process calculating optimal storage size is illustrated in Fig. 2.10. Increasing the ΔP (nominal power of the storage) also increases the costs of the storage (see also Eq. (2.6)). Finally, when the size of the storage is so big that there is not any more benefit from using it (storage costs line cross the benefit line in Fig. 2.10), then the iterative searching procedure of ΔP increasing stops. The optimal storage size ΔP_{opt} is found in the maximum of the benefits curve.

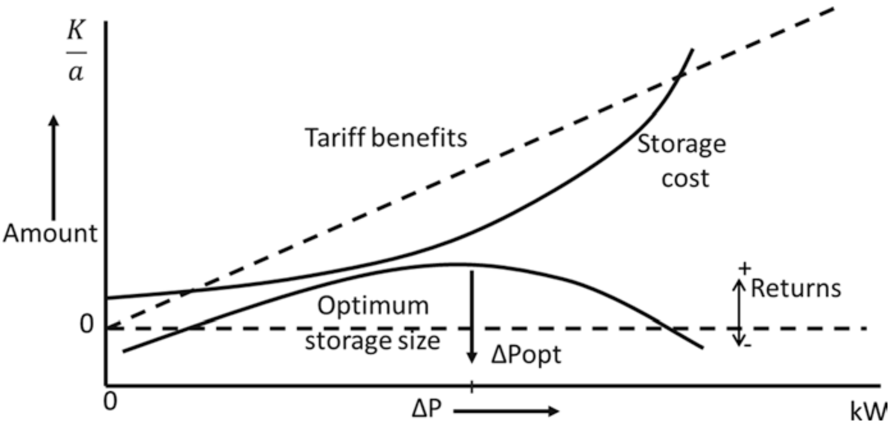

Fig. 2.10 Optimization of storage size for a given load curve. General idea

This approach can be implemented for longer periods of time, for example, 1 year. If a yearly load curve is not available, a yearly-approximated load curve can be composed using 12 daily load curves, which characterize Saturdays, Sundays and working days in all four seasons (spring, summer, autumn and winter). A yearly load curve for a network node in a German distribution system is shown in Fig. 2.11 as an example.

The calculation of the optimal storage mentioned above is based on cost balancing. Both the tariff benefits Z_t that correspond to the tariff power price (energy price and connection-power price C_{CON}—(2.8)) as well as the benefits corresponding to investment delays C_{InvD} (2.9) in various parts of the network must be summarized for planning purposes. On the other hand, the investment C^{I}_{EES} (2.6) and discounted costs C_{EES} (2.7) of a necessary BES should be identified. The economic balance depends strongly on the power P_{EES} and the energy E_{EES} of the optimal BES, and can be calculated by Eq. (2.10).

$$C^{I}_{EES} = \alpha_{EES}\, P_{EES} + \beta_{EES}\, E_{EES} \tag{2.6}$$

$$C_{EES} = C^{I}_{EES}\,(1+b_1)\sum_{k=1}^{T}\frac{1}{(1+i)^k} \tag{2.7}$$

$$C_{CON} = \alpha_{tar}\, P_Z \sum_{k=1}^{T}\frac{1}{(1+i)^k} \tag{2.8}$$

$$C_{InvD} = \sum_{l=1}^{N}\left(K^{I}_{Inv,l} \sum_{k=1}^{D(Inv^l)}\frac{1}{(1+i)^k}\right) \tag{2.9}$$

$$K_{Ben} = K_{CON} + K_{InvD} - K_{EES} \tag{2.10}$$

where: P_{EES}, is the power in kW, E_{EES} is the energy of the BES in kWh; α_{EES} and β_{EES} are specific power (€/kW) and energy (€/kWh) prices of the BES; α_{tar} is the

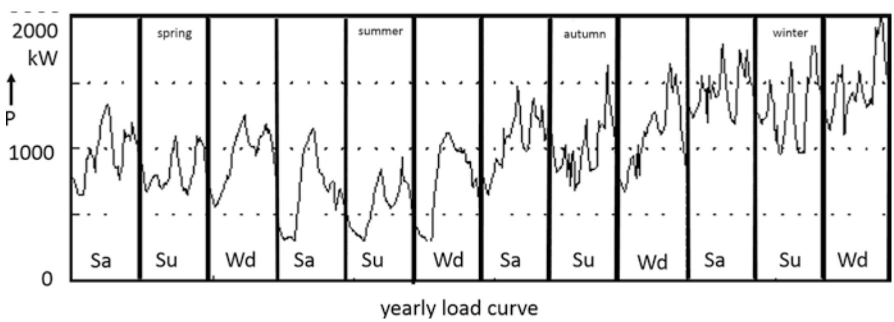

Fig. 2.11 An example of a yearly load curve

coefficient containing the tariff connection cost of power; p is the discount rate; T is the service life; β_{ex} is the coefficient containing the factor of the exploitation in the cost of the storage and C_{Ben} is the total cost benefits.

It is known from practical experience that the service life (T) of BES reflects on the battery life, and this depends on the operation mode of the BES and its technology. If the battery is handled with care, a T value of about seven to 10 years can be expected (a maximum battery storage T of 17 years has been reported[3]). However, this 7–10 year operation is less than one-third the life of other network equipment, e.g., cables, transformers and circuit breakers, and, therefore, the BES is relatively expensive when the discount calculation is taken into account. On the other hand, the discount calculation is necessary when the different scenarios of expansion planning are compared.

Regarding the constant values of the coefficients α_{EES}, $\beta_{EES,}$ α_{tar} and β_{ex}, the power and energy of the optimal storage depend on multiplication of the values service life *SL* and discount rate *p*. The optimization procedure is given by Eq. (2.11):

$$\Lambda\left(BES_{opt} : BES_{opt} => BES_i \rightarrow C_{Ben} = \max\right) \tag{2.11}$$

i ϵ N

where: BES_{opt} is the optimal BES, C_{Ben} is the benefit of the optimal BES and N is the number of elements in the set of storage.

The procedure for determining the optimal storage, e.g., corresponding to the yearly load curve given in Fig. 2.11, is shown in Fig. 2.12. The resulting benefits curve is shown in Fig. 2.12a. The tariff-benefit curve and the BES cost curve are

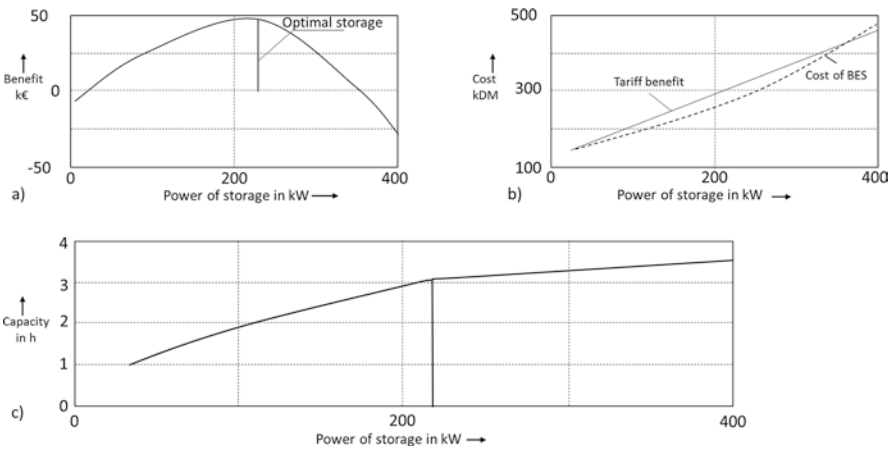

Fig. 2.12 Determining the optimal storage for the yearly load curve given in Fig. 2.11[4]

[3] Lifetime or service life (SL) depends strongly on the storage technology (also see Table 2.5).

[4] Results of a study carried out by the authors in 1994.

presented in Fig. 2.12b. The tariff benefits are shown by a continuous line, and the cost of BES is shown by a dashed line.

The benefit curve shown in Fig. 2.12a has only one maximum. The storage for which the benefits function reaches maximum is the optimal storage and is indicated by a vertical line in Fig. 2.12a. The storage capacity, computed using the yearly load curve, dependent on the storage power is shown in Fig. 2.12c. The optimal capacity energy of the storage corresponds to the optimal power, and it is indicated by a vertical line in Fig. 2.12c.

The optimal storage in this particular example has a nominal power of about 200 kW and the capacity of about 3 h, which correlates to 600 kWh of energy.

B: Determination of the Storage Module

Unification (assortment reduction) of rated quantities of the network elements and devices is an important factor for simplifying the exploitation of a power network. The power utilities have to keep equipment in reserve to be able to provide a quick exchange of elements after disturbances. The cost of these reserves depend on the level of unification.

The general problem of unification is to select the assortment of a given type in such a way that the total costs of investment, exploitation and reserve are minimal. To solve this problem for BES, it is necessary to determine the optimal sizes of an EES module for a particular network or network type.

A sensitive analysis is useful to determine the optimal storage module. First, the optimal storages have to be computed for the measured load curves, and then those sizes have to be standardized. In general, the modularization effects the expansion of the storage costs, and the target is to find a module size that makes it possible to minimize the cost increase for each scenario analyzed. The idea of unification is shown graphically in Fig. 2.13.

Unification of the storage size was carried out using the following algorithm:

- create the set of optimal storages for which the unification will be performed,
- group the optimal storages according to their types—sum up storages with the same value of power and energy,

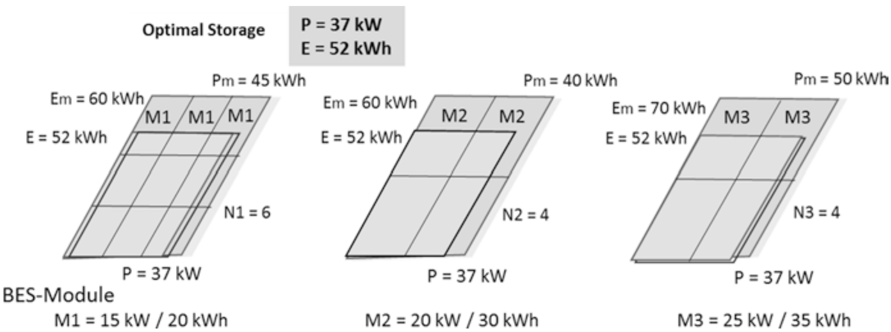

Fig. 2.13 Storage size unification process [21]

- propose a storage reserve equal to 1 % for each type of storage; at least five modules for each types of storage are necessary.
- propose a non-linear function to describe the converter costs which are dependent on converter power,
- determine the power and energy of the storage module for which unification will be performed, and
- perform unification computations whose result is the sum of the costs of optimal storages plus the storage reserve before the unification and the cost of all modules of the storage defined, taking into consideration its storage reserve after unification.

The unification procedure is given by Eq. (2.12) [22].

$$\Lambda\left(\text{Module}_{\text{opt}} : \text{Module}_{\text{opt}} = \text{Module}_{\text{i}} \rightarrow \text{C}_{\text{UNIF}} = \mathbf{min}\right) \tag{2.12}$$

$i \in M$

where: Moduleopt is the optimal module of BES, K_{UNIF} is the cost after unification and M is the number of considered modules of storage.

Three sets of planning data were used as an example for the unification procedure: German measurement data and Polish measurement data, both representing a typical urban distribution network; and model data obtained from the LOAD-MODEL program [23].

The general characteristics of the input data are given in Table 2.6.

The analyzed German network consists of ten medium voltage nodes; the Polish network has eight medium voltage nodes; and the modeled network has ten medium voltage nodes. The values of the average power are in the range 216–1997 kW in the German network nodes, 38–264 kW in the Polish network nodes and 59–444 kW for the network modeled with synthetic load curves.

Table 2.6 General characteristics of the input data

Type of data	Number of nodes	Name of node	Medium power in node, kW	Minimum power in node, kW	Maximum power in node, kW
German	10	n1	1049	710	1294
		n2	765	390	1154
		n3	1997	935	2931
		n4	910	281	1746
		n5	216	47	436
		n6	421	171	670
		n7	1002	561	1465
		n8	1097	904	1325
		n9	711	140	1948
		n10	1529	1263	1963

Table 2.6 (continued)

Type of data	Number of nodes	Name of node	Medium power in node, kW	Minimum power in node, kW	Maximum power in node, kW
Polish	8	p1	125	78	215
		p2	70	28	108
		p3	133	2	242
		p4	39	22	58
		p5	264	173	375
		p6	38	12	90
		p7	131	61	194
		p8	101	26	156
Model	10	m1	400	178	547
		m2	210	143	300
		m3	283	197	409
		m4	313	217	423
		m5	231	137	360
		m6	213	133	287
		m7	444	317	581
		m8	113	72	156
		m9	229	106	337
		m10	59	27	92

The following additional assumptions for all three networks were made:

- period of planning—20 years,
- yearly load growth—either 1, 2 or 3 %,
- time of storage service—6, 7, 8, 9 or 10 years, and
- discount rate—8, 9 or 10 %.

Due to the computations performed for all combinations of the values mentioned above, about 900 optimal storages were obtained for each of the nodes. In order to obtain the number of optimal storages for a particular data set, one has to multiply 900 by the quantity of nodes present in these particular sets of data.

The power of optimal storage in most cases did not exceed 10 % of the maximal power-peak value in the network node. Generally, the longer the period of economical exploitation (here time of storage service), the bigger the expected size of the BES. However, with the growth of the discount rate, the power and energy of optimal storage decrease slightly. The capacity of optimal storage, defined as a ratio of energy to storage power, is in the range of 0.67 and 2.39 h. This data and the information from converter and battery producers are authoritative for the preselection of a module set.

The reference BES cost K_{REF} for the comparison of the results is introduced. This cost is computed as the sum of all storage costs during the whole planning period of 20 years. A discount method was used to sum up the costs.

The reference costs of optimal storage together with the storage reserve are:

- for the German power network data—2.76 million EUR,
- for the Polish power network data—0.61 million PLN,[5] and
- for the model power network data—0.22 million EUR.

The reference cost for the German power network is about ten times higher than the reference costs for the Polish and model network. This correlates well with the values of the maximum power in the networks' nodes (see Table 2.6).

The results of unification computations are presented below in Table 2.7 and in Fig. 2.14. The set of preselected modules are listed in column 2. The costs after

Table 2.7 Storage module unification results

Case Number	Parameters of storage power/energy	Costs after unification					
		German		Polish		Model	
	kW/kWh	Mln EUR	k_{REF} in %	Mln PLZ[a]	k_{REF} in %	Mln EUR	k_{REF} in %
1	5/10	3.25	117	0.48	77	0.35	157
2	10/10	2.26	81	0.35	57	0.29	130
3	10/15	1.90	68	0.32	53	0.24	107
4	15/15	1.66	60	0.30	49	0.23	102
5	15/20	1.46	53	0.29	48	0.21	93
6	15/25	1.46	53	0.30	49	0.20	89
7	15/30	1.53	55	0.31	51	0.20	91
8	20/25	1.24	44	0.26	43	0.19	86
9	20/30	1.23	44	0.27	44	0.18	84
10	20/35	1.26	45	0.28	46	0.19	86
11	20/40	1.32	47	0.30	49	0.20	91
12	25/35	1.24	44	0.31	51	0.21	98
13	25/40	1.25	45	0.32	53	0.22	100
14	30/40	1.26	45	0.36	59	0.24	109
15	30/45	1.26	45	0.37	61	0.25	111

[a]PLN – Polish Zloty.

[5] Corresponds to about 0.15 Mio €.

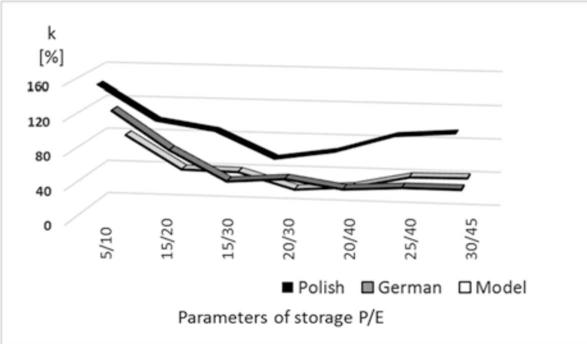

Fig. 2.14 The course of coefficient $\boldsymbol{k}_{REF}$ for German, Polish and model data

unification for the German, Polish and model data are given in columns 3, 5 and 7, respectively. The values of a coefficient k_{REF}, describing the percentage value of costs after unification in contrast to reference costs, are shown in the columns 4, 6 and 8.

The optimal size of the BES module is 20/30 kWh for the German and model data, and 20/25 kWh for the Polish network. We can see that unification of the storage size causes a large decrease in the global storage costs in all of the cases analyzed (up to threefold).

The course of the optimization curve is especially flat for the German data with larger storage sizes. The optimization curves for the Polish and model data have a more clearly defined minimum. Taking this into account, the choice of the optimal module for the German network depends more on the network structure and can differ from one power utility to the other.

C: Integration of Storage into the Distribution Planning Process

The objective of power utilities is to meet the electric energy needs of customers as economically as possible, with the required degree of reliability and quality. Expansion planning, which is a continuous task of these utilities, helps them reach this objective. It is decisive for power system optimization and consists of a sequence of network expansion scenarios for the future, usually 20 or 30 years.

On the medium voltage level, the distribution systems were initially planned as a loop, but most of them are afterwards operated radially. The loop construction is preferable from the reliability point of view, while the radial operation reduces the operation and protection complexity of loop systems.

The load growth is an important parameter when planning expansion. The network apparatus (cables, overhead lines, transformers) must be designed to take the peak load into account. The yearly load growth has slowed in recent years so that it is lower than previously and now amounts to 0.5–2 %. This requires changes in the planning methodology and a more careful planning of network expansion, which in turn affects the new planning scenarios [22].

In reality, the supply to customers has a characteristic daily cycle pattern. A power peak at noon and a lower demand at night (typical load curve for central Europe) cannot be avoided by changes in the network configuration. For this reason, several utility management techniques for peak load leveling are in use, such as power importation, demand-side management controlled by economic incentives or penalties and various energy-storage systems.

In principle, energy storage devices are used by the utilities to convert economical off-peak electrical power into other forms of energy from which electricity can be regenerated during periods of peak-power demand.

The influence of the storage devices on the expansion plans should be analyzed parallel to the network planning process. So the planning with energy storages requires an integration of new tools, such as load-curves forecasting, energy-storage models and storage-optimization methods with horizon planning of the power-network expansion. This only leads to the recognition of the usability of optimum storage before an expansion decision is made. Based on the developed models, the new network-planning procedure using dynamic programming can be applied which uses the simple property of multistage decision processes given by Bellman [24]. It is claimed that "an optimal policy has the property that whatever the initial state and initial decision are, the remaining decision must constitute an optimal policy with regard to the state resulting from the first decision". The elements of this three-step process are: optimal storage dimensioning in the network nodes, ranking of the nodes and storage placement in the horizon planning. The three steps of a developed procedure are shown in Fig. 2.15. The investigations do not depend on the kind of storage, but parameterization and calculations are only done taking into account battery storage, because this is the only industrially tested storage technique currently available in this range of power.

The planning process starts with the optimization of the storage dimension S_l in the l = 1 … m network nodes (step 1). It follows the procedure as given previously in this chapter and leads to the solution of Eq. (2.13):

$$\underset{l=1..m}{\forall}\left\lfloor S_l(P_l, E_l)\right\rfloor \Rightarrow f(C_l) = \min_{l=1..m}(\Delta C^B_l) \tag{2.13}$$

where: m is the number of the nodes in the analyzed network

$$\Delta C_l^B = \sum_{k=1}^{T}\left[B_k(\Delta E) + B_k(\Delta P) + C_{k,P_l}\right](1+i)^k \tag{2.14}$$

$B_k(\Delta E), B_k(\Delta P)$ are the benefits to energy and power losses, C_{r,P_i} is the tariff benefit for the peak shaving, P is the discount rate and L is the service time of BES.

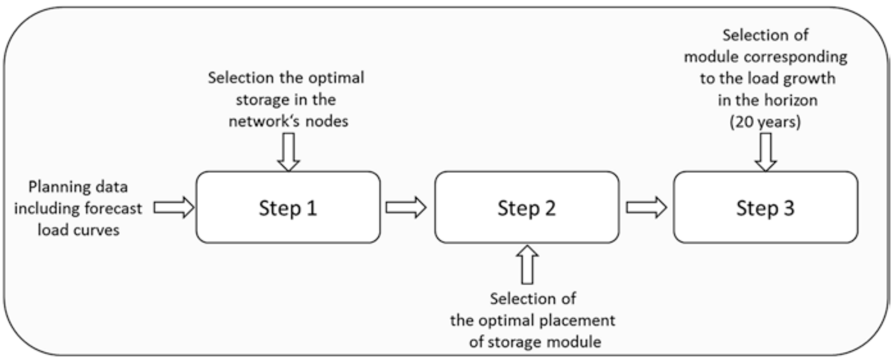

Fig. 2.15 Network planning with BES as a dynamic programming problem

The use of the BES in one of the loop's nodes influences the parameters such as the maximal load, the load factors themselves and the neighboring nodes. The level of influence depends on the correlation of storage size and times of peak-load behavior in the loop.

The order of the nodes in a distribution network loop can be determined by analyzing the peak-shaving aspects caused by the optimal storages selected previously. For this reason, the second step yields the order Γ of the nodes, which corresponds to the location's preferences of the different storage. Equation (2.15) describes this process when only the cost benefits have been taken into account:

$$\Gamma = \underset{\max,\, i=1..m}{\text{sort}} \left\{ f(C_i) \right\} \tag{2.15}$$

If some other criteria needs to be considered during the ordering process (e.g., peak shaving in the neighboring nodes or peak shaving in the main station), a multicriteria decision has to be made.

The third step of the algorithm is a recursive placement of the storages corresponding to the order Γ, expected overload Po in the planning year, and the cost balance between costs of storage C and cable or overhead line C^L. This process, done separately for each loop M, corresponds to Eq. (2.16):

$$\underset{j \in M}{\forall} \left((E_j, P_j) \Rightarrow E_j^S = \sum_{i=1}^{m_j} E_j^i;\ P_j^S = \sum_{i=1}^{m_j} P_j^i \right) \tag{2.16}$$

subject to the set of constraints of the form:

$$E_j^S \geq E_j \tag{2.17}$$

$$P_j^S \geq P_j \tag{2.18}$$

$$C^L > C^S\left(E_j^S, P_j^S\right) \tag{2.19}$$

with explanations in the text.

A permissible overload Pj can be detected by analyzing the daily load in each of the loops j = 1 … m. The choice of the expansion strategy follows economic criteria. One of two strategies is used to avoid overloading:

- Installation of one or more distributed energy storages in the overload loop B and G, in the order corresponding to the node ranking Γ, or
- Reinforcement of the network using parallel cables of the same cross-section in the overload locations C.

A system of programs called GENPEX (*G*raphical *E*lectric *N*etwork *P*lanning *Ex*pert System) is used for the interactive planning of the distribution network, and it is extended for computation with energy storage. Additionally, the neural-network load-prediction model and optimization- storage model are implemented in this software system. The GENPEX database is prepared so that the characteristic of loop nodes using twelve characteristic daily load curves is possible.

The expansion planning with BES is shown in an example. An expansion scenario is computed for an existing 10 kV network. Starting in the year with the peak load in the networks loops *G, B* and *S* (see Fig. 2.16b), a 1 % yearly growth of load has been set.

The load curves in the nodes are predominantly urban-specific. The invariability of load curves in the network nodes during the planning period was assumed. Moreover, the following is given:

- Time of service (ToS) for battery subsystem of 8 years;
- ToS for cable and other BES subsystems of 30 years;
- specific cost of BSE: 580 $/kW and 260 $/kWh:
- specific cost of 10 kV/150 mm^2 cable of 160 $/km;
- discount rate of 8 % and discharge rate of BES of 80 %.

The expansion scenario uses a 20 kW/35 kWh-module BES and was computed using GENPEX. The results of the computation are presented in Fig. 2.16. The planning situations for the years seven and eight are traced in the geographically oriented Fig. 2.16a. The loops in Fig. 2.16b are also shown in an unfolded form for the visualization of time expansion of the network.

One can see in Fig. 2.16a that storage modules (triangles) are situated in different nodes of the loops because of the distributed plan for BES. In the loops *B* and *G*, the storages shifted the cable investment only once in the left and right part of both loops (Fig. 2.16b). The overloaded part of the loops, resulting from the yearly load growth, is always the cable parts that are close to the main station, for example, B1. We can see that the optimum storages selected using the order Γ are also situated far away from this part (e.g., B6, B9, G4) and that they influence the load flow in the loops in order to avoid overload.

It is important from the economic point of view that the modules remain in operation for eight years. A storage shifting into the other node is often required during this time period. For example, the three modules of BES from node G4 can be relocated in year seven to node B9. Another possibility corresponds to the five modules stored in node G2, which can be relocated to node B12 with a time break of 2 years. It is also certainly possible to manage single-module exchange, but this topic will not be discussed in this chapter.

A total of 35 BES modules were used in this network over a 20 year period, and the total combined time of use is 44 years. The maximum total power of the storages appears in year nine and is 400 kW, which corresponds to about 3 % of peak power of the loops analyzed.

The use of BES does not worsen the reliability indices of the power network. The reliability study has shown that the use of small decentralized module-battery storages (MS; see Fig. 2.17) improves the reliability indices compared to the other possible expansion measures, for example, diesel generator (DG; see Fig. 2.17).

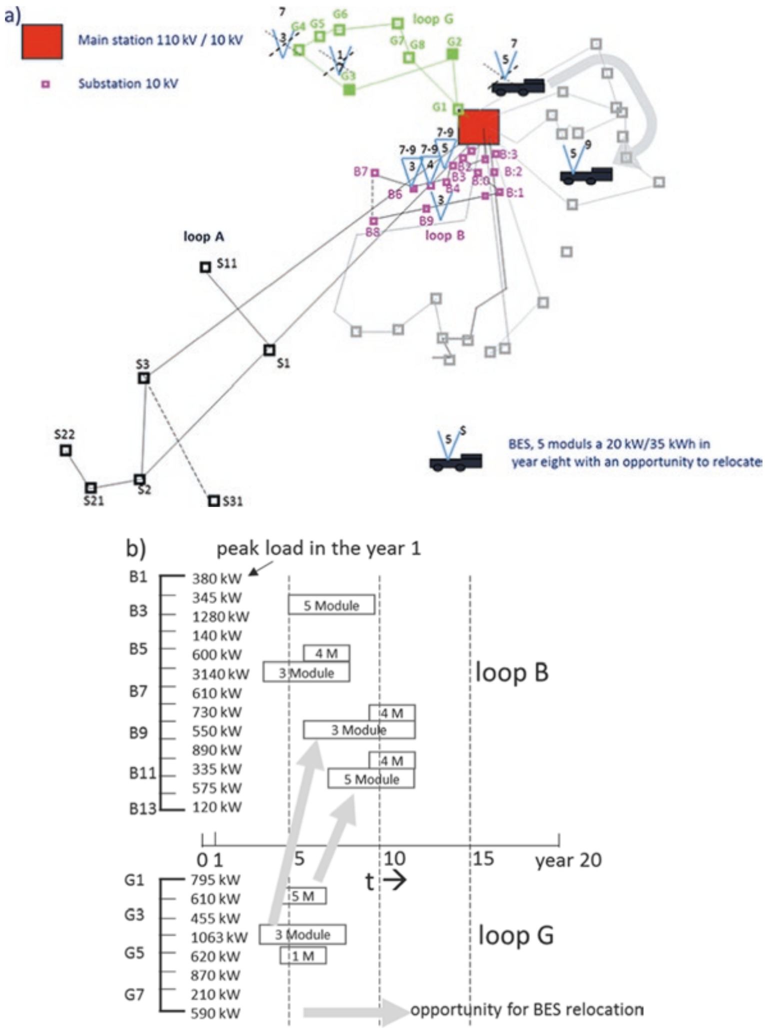

Fig. 2.16 Planning example: (**a**) network plan with dislocated module BES for planning year seven, eight and nine, and proposal for moving BES, (**b**) network loop expansion in a time horizon of 20 years and using module BES

2.3.4 Standardized Models of BES Using the Surface and Interface Structure (SIS)

An example of a detailed concept of the surface and interface structure is presented exemplarily in this chapter by modeling two types of BES. The first is a classic lead-acid battery and the second is a storage unit with higher energy density, namely a high-temperature battery (NaS). Today, Li-ion batteries are extensively used in

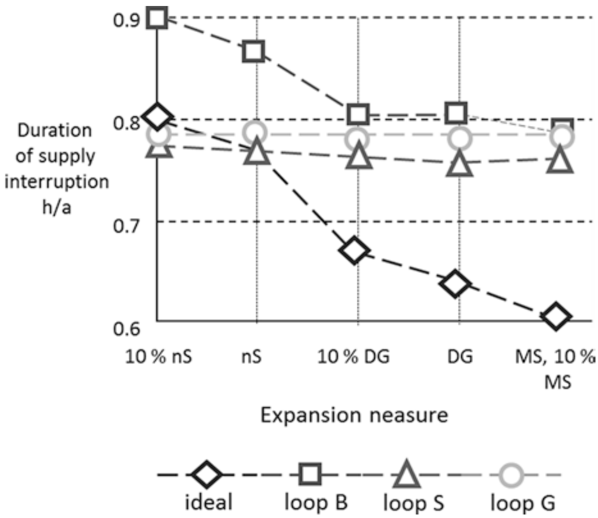

Fig. 2.17 A comparison of supply-interruption duration for various expansion measures

BES for the smart grid because they can be produced with high capacities. This battery type offers high operating voltages in comparison to other batteries, such as lead-acid batteries and sodium-sulfur batteries. Other benefits of these batteries include light weight and compact size, which will augment their adoption into the energy-storage system. The methodology presented here for the two battery types can also be used for the Li-Ion battery.

A: The Lead-Acid Battery Model

A simplified model of battery integration was used as a basic structure for the storage unit [25]. It is based on the main assumption that the battery, used primarily for peak-load shaving, will be brought again to the state of full charge after a 24-h cycle. Therefore, the losses for chemical into electrical energy conversion and self-discharge losses can be merged together.

The most important factor of the PhS of the battery model is its state of charge (SOC). The internal behavior of the battery is based on the dependence between charge and discharge power and the SOC and is controlled by the charge-control unit. The bi-directional flow of the energy is ensured through the inverter, which, together with the transformer unit, comprises the NCS for the battery-storage unit (Fig. 2.18).

The demands of energy are in the form of active power, which should be delivered from the battery to the network. This demand is transferred by the interface inside the battery model, so that the battery sees it as a discharging command. The model examines its SOC and, depending on it, provides the desired and/or the possible energy quantity. The power during discharging is nearly constant up to the adjustable threshold value of, for example, 30 % SOC. When this level is reached, the battery shuts off the discharge process in order to avoid excessive discharging.

The battery model disposes of the charge-control unit, building its IOS surface. The unit is responsible for the charging process, so that there is no charge permission

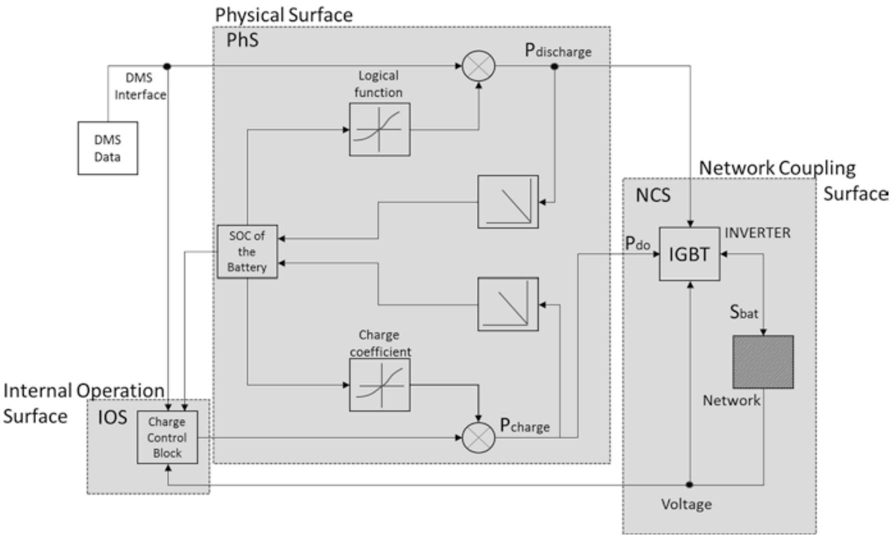

Fig. 2.18 The integration model of the lead-acid battery unit with integrated SIS

required from DEMS. However, the charging process is only possible when all of the following circumstances are fulfilled: the battery is not in a fully charged state, the voltage amplitude at the connection node in the network lies within the allowable band and there is no energy demand from the DEMS. During the process, the charge coefficient, which reflects the behavior of the inner battery resistance, is considered because it slows down the energy ingestion at high values of the SOC.

The battery-unit model is coupled with the network by an inverter and a transformer—the NCS surface of the unit. The inverter disposes of the voltage-control unit, which allows for voltage- amplitude control using reactive and/or active power injections. This control is made within various limits, drawn from the apparent power of the transformer, the maximal active power that can be delivered by the battery and the cos φ of the inverter module. The inverter losses are considered to be 3.5 % of the apparent running power.

B: The High-Temperature Battery

The high-temperature battery is a storage system with high energy and light weight. The operation temperature of the system is 250–350 °C, which requires a very good insulation of the system and the presence of a controlling unit, which observes and controls the battery temperature. A light weight is achieved through the usage of light alkaline metals for the negative electrode. It can be lithium, sodium or an aluminum dioxide that contains sodium ions, e.g., solid electrolyte aluminum. A high-temperature unit with a sodium-nickel-chloride battery is presented in this section.

A long-term model of a 30-Ah battery is presented exemplarily below. The battery consists of 220 cells connected in a series. The maximal power of this unit can rise to 17 kW by using the idle voltage of a single cell of about $U_0 = 2.58$ V.

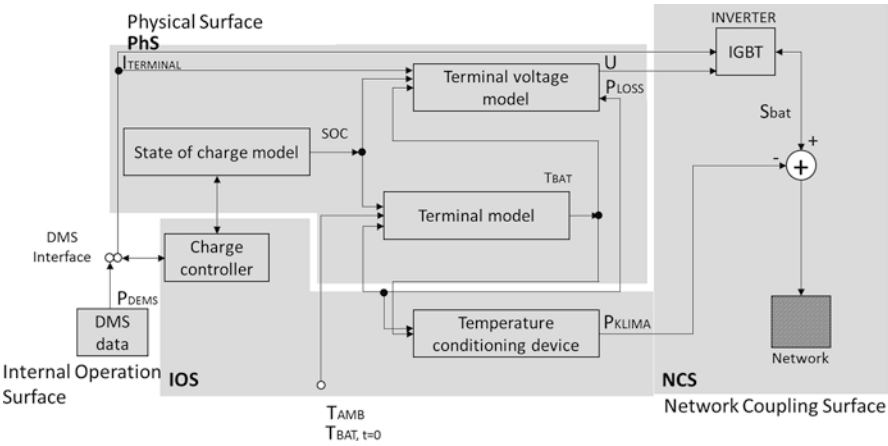

Fig. 2.19 Model of the high-temperature battery unit with integrated SIS

The model consists of four interconnected sub-models: the SOC model, the terminal voltage model, the thermal model and the model of a temperature conditioning device. All of the sub-models are then embedded in NETOMAC®-Macro software, which is additionally furnished with other interfaces and standardizes the model according to the structure shown below in Fig. 2.19.

The DEMS demands energy in the form of active power that should be delivered from the battery to the network. This demand is transferred by the interface to the inner battery-current demand, so that the battery sees it as a discharging command with the constant current. The battery can work between a fully charged state (30 Ah) and a null charged state (0 Ah). When the level of discharge is reached, the battery shuts off the discharge process. The model examines its SOC and, depending on this, the physical internal processes are simulated in the terminal voltage model and thermal model. The power during discharging is not completely constant, because of the strong influence of the internal losses (inner battery resistance), which, in turn, depend on the battery's SOC and its internal temperature.

The battery model additionally disposes of the charge-control unit and the temperature-conditioning device, comprising its IOS surface. The former is responsible for the charging process, which is possible only when the battery is not in a fully charged state and there is no energy demand from DEMS. During the charging process, the controller prevents an override of the inner cell voltage, which can be dangerous for this type of battery. The battery temperature-conditioning device maintains the inner temperature of the battery at 250–350 °C. A temperature drop (caused by lengthy stand-by operation) to the minimum value (250 °C) turns on the heating unit (about 100 W) to keep the temperature of the battery at this level. When the temperature approaches 350 °C (in a long charging or discharging process), the cooling unit turns on. The electrical demand of this unit is proportional to the maximal inner losses of the battery, which, in turn, depend strongly on the current demand. The electrical demand caused by the conditioning device is then subtracted from the total power produced by the battery (Fig. 2.19).

The resulting energy is transformed through an inverter and feeds the network. The inverter and a transformer form the NCS surface of the unit. There is no voltage control and, if needed, the inverter allows for the cos phi to be set to some other constant value.

2.4 Storage Systems in Isolated Power Systems

2.4.1 Introduction

Chapter 1 discussed how the use of electric-energy storage (EES) for niche implementations can help justify future widespread application of this technology. One of the best examples for such niche implementation is the use of EES in an isolated power system (IPS). When an IPS is equipped with renewable generation, a stabilizing element, such as EES, is necessary for smoothing volatile generation and enables secure operation of the IPS system.

Different methodologies can be used for the optimal design of IPS systems, e.g., dynamic programming, mixed-integer linear programing and iterative methods [26]. In this chapter, two methods focused on EES dimensioning will be presented, explained and discussed:

1. A case-based method for optimal dimensioning of EES in an IPS systems using an iterative algorithm for optimal storage calculation and selected indices for storage-site approximation.
2. A multi-criteria method for planning IPS systems.

2.4.2 A Case-Based Optimization of Electric Energy Storage Size in an Isolated Power System

Optimal dimensioning of EES, in the range of MW, will be illustrated in this chapter using a specially constructed case study [27]. This case study addresses the planning phase of an IPS within which the optimal size of the EES must be determined. The optimal size or dimension of an EES is characterized by two storage parameters: storage power and storage capacity. For the optimal dimensioning of EES, the generic model of storage presented in Sect. 2.3 is useful. After determining the optimal parameters of a generic EES, a storage technology can be chosen according to the application investigated [28]. In the case study specified here, a battery type of EES was considered (see also Chap. 5).

The input data in the IPS analyzed are generation mix, demand and energy-storage range (see Fig. 2.20). The generation mix consists of a combination of conventional generators (e.g., diesel engine or micro gas turbine) and generators based on renewable sources (e.g., photovoltaic: PV and wind turbines) [26, 28]. The IPS load profiles for typical working days, and Saturday and Sunday were used to calculate

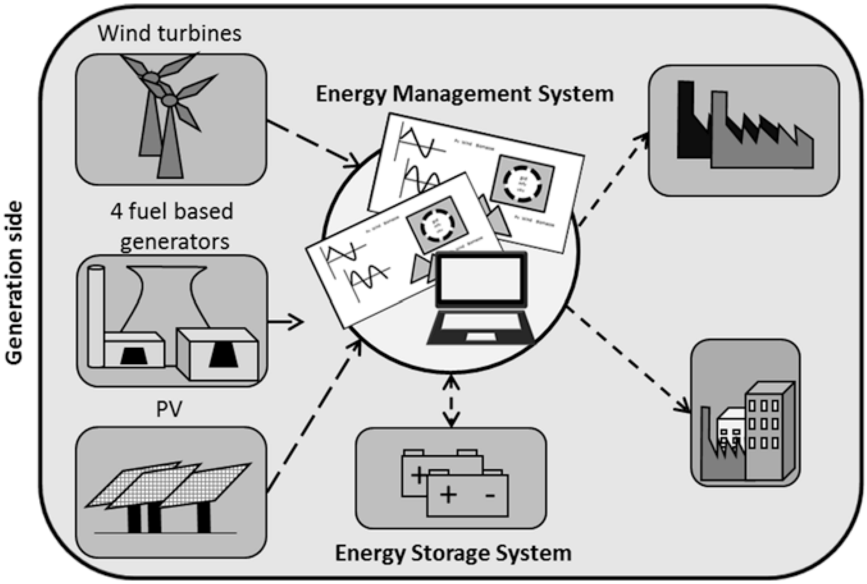

Fig. 2.20 Structural analysis of the isolated power system

the optimal schedule of generation. These profiles depict typical loads for industrial, residential and tertiary purposes. Additionally, through the data collected from solar irradiation and wind speed, it was possible to simulate the generation profiles of the plants based on RES.

Optimal Storage Capacity

The methodology for finding optimal storage parameters, in this case, power and capacity, is based mainly on the following procedure:

1. Set up an initial generation mix:
   i. Conventional generators can cover 60 % of the energy demand,
   ii. The PV and wind generators must be sized so that they cover the remaining portion of the load (considering a week-long energy demand)
2. Set up a time period of investigation. The investigation will be carried out for one typical representative week[6] in the year. The demand curves and generation profiles for wind and PV for the days in the representative week must be fixed.
3. Initial storage power is set up as 50 % of the basic load and four-hour capacity (about 15 % of the energy demand).
4. The optimal schedule for one week for both generation and storage, according to the given profiles (see step 2), should be found using integer linear programming [29].

[6] The representative week consists of five working days, each day with the same profile, and Saturday and Sunday. The week should be selected, depending on the region, in the maximal demand season. The necessary time profile's accuracy is ¼ h. The data for one year can also be used for this investigation, if they are available.

5. The capacity of storage will increase iteratively within the given range, and step 4 will be repeated.
6. The energy deficit in the IPS (the amount of energy that must be imported) is computed in each step, and the amount of RES power that was not fed into the grid is found. The aim of the optimization is to minimize both those values.
7. If the step of the storage capacity change is quite small, the accuracy of optimal storage determination will be high.

Case Study 1

In case study 1, calculation concentrates directly on optimal storage dimensioning considering the load curves for demand and generation—using the method mentioned previously—and will be carried out iteratively by increasing the storage capacity.

The results of such a calculation are presented graphically in Fig. 2.21. The following input data for case study 1 is fixed:

- max load—12 MW
- renewable generation
  - wind turbine—7 MW
  - PV—8 MW
- conventional generators—4 × 1 MW
- storage
  - capacity 4—6.5 h, with steps of 0.5 h
  - power 1—7 MW, with steps of 1 MW

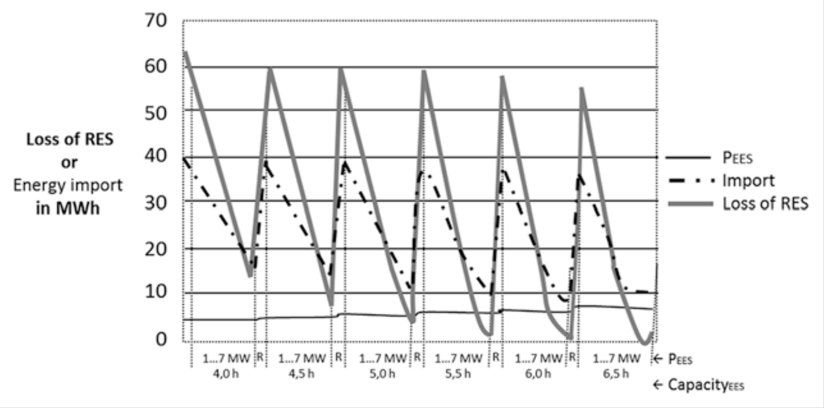

Fig. 2.21 Optimal power and capacity of EES. The result of iterative optimum search

The iterative algorithm was used in the investigation as follows:

```
for E_EES: = 4 steps 0.5. to 6.5
begin
   for P_EES: =1 step 1 to 7
   begin
      energy_schedule_for_week: = find_necessary_generation
(demand, generation, storage)
   end{P_EES}
end{E_EES}
```

The influence of storage parameters on the integration[7] of energy generated by RES was observed during the simulation. By increasing the storage capacity from 4 to 6.5 h (see black line in Fig. 2.21), the amount of electric energy generated by the RES that can be integrated into the IPS also increases. The dotted line in Fig. 2.21 illustrates the energy import, which decreases when storage capacity increases. The import of energy is reciprocally proportional to the integrated energy mentioned above. The minimal storage capacity that allows for all of the RES generated energy to be integrated into the IPS system during the test week amounts to 5.5 h (see Fig. 2.21, grey line by P_{EES} = 7 MW). However, it is still necessary to import energy into the IPS system with such storage capacity. This is simple to explain: The generation mix is too small to cover the full demand at all time periods. To avoid the import of energy, it is necessary to increase the size of the generators (e.g., nominal power of the wind generator). The new size for a wind generator that makes it unnecessary to import energy can also be found iteratively. Results of the corresponding calculation are presented graphically in Fig. 2.22. By powering up the wind generators to 11 MW (Fig. 2.22, grey line, step no. 5), the IPS system's own generators can cover loads fully every time (Fig. 2.22, black line) that the system reaches full autonomy.

Now, the new optimal energy storage size can be computed using the same methodology for the generation mix as before, but this time with an 11 MW wind generator. In this case, the optimal storage has parameters of: 8-MW power and 13-h capacity. With such a storage system, the IPS can also cover its own demand at all time periods. It should be noted that full integration of the RES inside the IPS was reached with smaller storage using 7-MW power and 5.5-h capacity, but with the necessity of importing energy.

[7] Energy integration means that the renewable generation quells demand. The surplus of renewable generation cannot be integrated directly and can, for example, be stored for feeding into the network when there is a generation deficit.

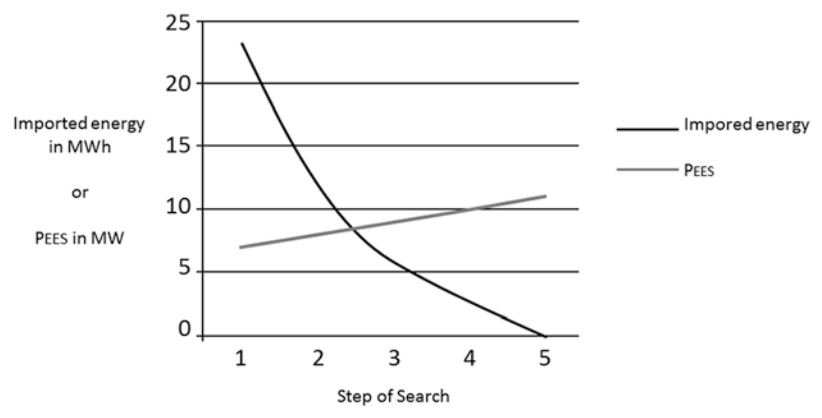

Fig. 2.22 Results of iterative optimization of wind generator nominal power for full autonomy of the IPS

Following the technical results, the economic calculations were carried out. Discounted costs C_{EES} of EES were calculated using the formula given in Eqs. (2.5) and (2.6). The discounted cost calculation for storage, import energy and losses was calculated for one week, taking into account a discount factor r = 5 % and a lifetime of the EES of T = 10 years [27]. The investment costs of generation were not considered in this calculation. The summarized cost index C_{index} is presented in Eq. (2.20).

$$C_{index} = C_{EES}^{week} + C_{import}^{E} + C_{loss}^{RES} \tag{2.20}$$

where:

- C_{import}—cost of imported energy for balancing the load,
- C_{loss}—cost of RES energy not integrated, and
- C_{EES}^{week} —weekly recalculated costs of storage [27].

The full integration of renewables in the IPS is reached at the cost index K_{index} and is equal to 84,380 Euro which corresponds to about 76 €/MWh. However, in order to ensure that the loads are always covered from local sources, a cost of about 158 €/MWh is needed, which presents a particularly high impact of storage costs on the total IPS energy costs. The results of this investigation show that full IPS autonomy is very costly, because the use of rather large storages is necessary in this system. This storage is only partially used (see also Fig. 2.24), which influences the economics.

Case Study 2

In this investigation, the IPS system given in Fig. 2.20 is first analyzed without considering EES. Only the generation and the demand profiles for one test week are considered. Two specific indices [30] that have an effect on storage dimensioning (sizing) indicated by the case study 1 investigation are calculated. These are

- the amount of unfed energy (not integrated into the IPS system) from RES, and
- the amount of imported energy.

These values are dependent on the time correlation between the load curve and RES generation curves and, taking into account the volatile RES generation, are stochastic. Smoothed (levelled) average values of these indices[8] can be obtained by simulating one week of IPS operation. Those values can be used further to approximate the storage power and capacity needed for the IPS analyzed. The unfed (not integrated) RES energy can be expressed by Eq. (2.21), while the imported energy can be calculated by Eq. (2.22):

$$E_{uf} = \int_{t=0}^{1week} ((P_t^{RES} - P_t^{Dem}) / P_t^{RES} \geq P_t^{Dem})dt \qquad (2.21)$$

$$E_{imp} = \int_{t=0}^{1week} ((P_t^{Dem} - P_t^{Gen}) / P_t^{Dem} \geq P_t^{Gen})dt \qquad (2.22)$$

where P^{Dem}, P^{RES} and P^{Gen} represent the power demand, the power generated by RES and the power generated by all generator curves, respectively, for a time period of one week.

Taking into account the peak import load expressed by max(P_{imp}) and peak unfed power expressed by max(P_{uf}), the storage parameters (storage power P_{EES} and storage capacity h_{EES}) can be estimated using Eq. (2.23):

$$\begin{aligned} P_{EES} &= \max(\max(P_{imp}), \max(P_{if})) \\ h_{EES} &= \max(\max(\frac{E_{imp}}{P_{imp}}), \max(\frac{E_{uf}}{P_{if}})). \end{aligned} \qquad (2.23)$$

[8] By using of one year data sets, it is to be expected that the indices will be more levelled and more useful as a starting point for exact calculations.

Figure 2.23 provides the graphical results of the IPS operation for the data given in case study 1. The demand curves for one week (area in grey) and charge/discharge of the optimal storage 8 MW/13 h (area in black) are shown in this figure. Corresponding to this calculation, the storage state of charge (SOC) curve is presented in Fig. 2.24. Using the methodology given

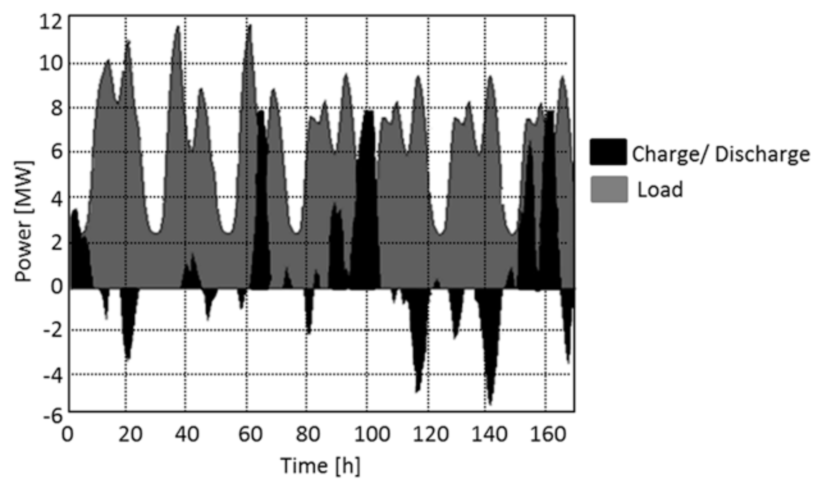

Fig. 2.23 Load curve for the test simulation and corresponding storage-operation diagram

Fig. 2.24 8 MW/13 h EES. State of charge (SOC) for one test week

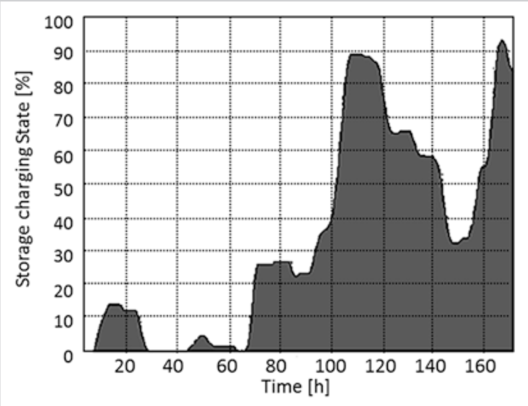

Table 2.8 Approximate storage size

Generation mix	Imported energy in MWh	Unfed RES energy in MWh	Approximate storage size MW/h
Demand 12 MW Wind 7 MW PV 8 MW CHP 4 MW	133	71.8	6/11 or 6/22
Demand 12 MW Wind 11 MW PV 8 MW CHP 4 MW	109	199	6/13 or 11/18

by Eqs. (2.21)–(2.23), the calculated storage sizes are depicted in Table 2.8. The resulting EES power values for the first-generation mix (wind generator 7 MW and energy import into IPS necessary) is 6 MW for both indices: the unfed RES energy and the imported energy. The corresponding values are 6 MW and 11 MW for the second-generation mix (wind generator 11 MW, no energy import into IPS). Therefore, the resulting storage size is 11 MW and 18 h and is higher than the storage size we calculated using the iterative methodology in case study 1.

The over-dimensioning of the storage size in this investigation can be explained by the use of a time-dependent integration of stored energy which allows for the assignment of the storage SOC. This simple methodology, useful in this case, does not fully consider the time correlation between demand and generation curves. A full model simulation using mixed integer linear programing, as used in the optimization method proposed before, allows for a more precise sizing of the storage. However, the approximation method gives a very good and fast starting point for an iterative algorithm and makes it possible to find a quick global optimum.

Case Study 3

A comparison of costs for the optimal EES investigated and calculated above, taking into account different storage technologies [28], was carried out. The results of this investigation are given graphically in Fig. 2.25. The best result (minimal costs) was obtained for batteries and CEAS technologies, which was expected considering the size of the IPS and planned operation mode of the EES. The use of flywheels or super-capacitors may be very expensive, since these technologies are more suited for power-quality purposes and are not easily adaptable for IPS purposes (see also Chap. 5). Construction of a hydro-storage is, coresponding to the size needed, not realistic.

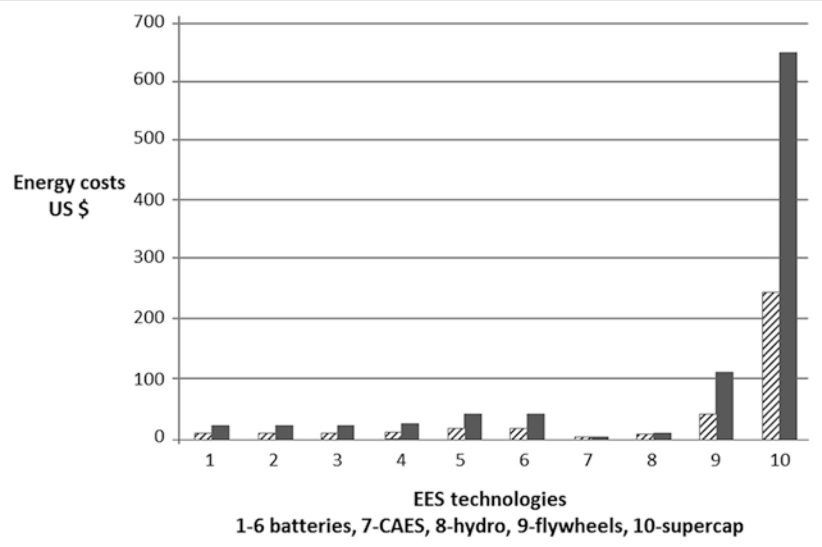

Fig. 2.25 Results of the economic comparison of ESS technologies for an IPS

2.4.3 Multi-Criteria Optimization of IPS

Multi-criteria decision analysis (MCDA) methods are used widely for planning and upgrading energetic infrastructures, such as power generators, transmission and distribution lines or storage systems, taking into consideration various criteria, such as economics, reliability and social issues. The MCDA analyses use various techniques for solving the optimum [Lombardi].

The MCDA can be divided in two categories: multi-objective decision-making (MODM) and Multi-attribute decision-making (MADM). The MODM is characterized basically by the existence of multiple and competitive objectives that have to be optimized against a set of feasible and available constraints. The analytic hierarchy process (AHP), which belongs to the category MADM, is one of the methods most used by the decision-makers for planning problems related to the energy sectors and, here especially, to micro-grids. It works by organizing the problem into a hierarchical structure in which the goal of the problem is set at the top level, the criteria

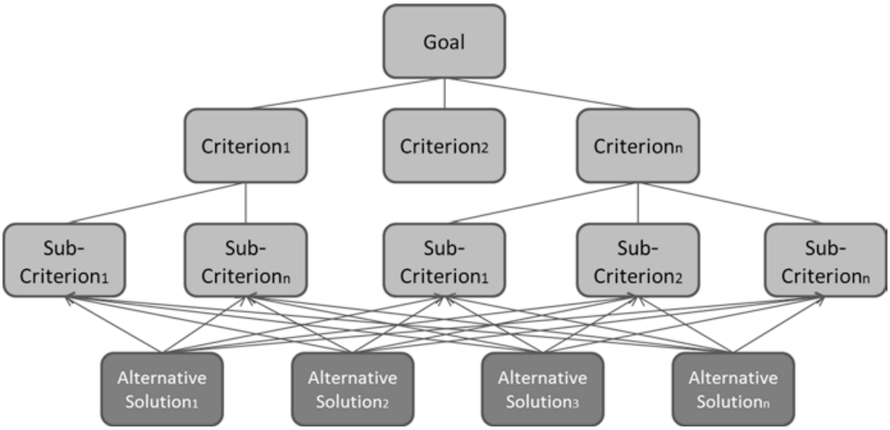

Fig. 2.26 Example of a hierarchy structure

and sub-criteria are set at the middle levels and the alternative solutions are set at the bottom level of the hierarchy (see Fig. 2.26). The aim of the AHP is to evaluate the alternative solutions according to a list of priorities which fulfil the main goal of the problem.

The AHP approach is composed of six steps. In the *first step* the objectives of the problem and the criteria considered have to be identified. In the *second step,* the problem is organized into a hierarchical structure, as depicted in Fig. 2.26. In the *third step*, the decision-makers, based on their own experience and knowledge, compare all the elements that belong to the same level in a pairwise fashion. The elements are compared by considering their order of importance. The Saaty scale is used to fill the order of importance (see Table 2.9). Based on the pairwise comparison, the n × n reciprocal judgment matrix **A** is set up, where *n* is the number of elements compared. In the *fourth step*, matrix **A**, the largest positive real eigenvalue λ_{max} and the corresponding eigenvector *w* (local priority vector) of the judgement matrix **A**are calculated for each reciprocal judgment with Eq. (2.24). The local priority vector establishes the ranking of local priorities among the elements within the same hierarchy level. In the *fifth step*, the consistency of each judgment matrix is checked.

In order to do this, firstly, the consistency index (C_i) is calculated with Eq. (2.25). Then, using Eq. (2.26), the consistency ration (C_R) is evaluated by rating the consistency index to the random consistency index (R_I), which is listed in Table 2.10. The random consistency index represents an average of the consistency index, which is obtained from randomly generated reciprocal matrices using the Saaty scale (1/9, 1/8, …, 1, … 8, 9). This varies according to the size of the matrix: For example, the random consistency index is 1.12 for a matrix with five elements. If the consistency ratio is smaller than 0.1, then the judgement matrix can be considered as consistent, otherwise, the decision-makers have to reevaluate the elements belonging to the same hierarchy level. After evaluating all the local priority vectors and proving that the judgment matrices are consistent (through steps three, four and five), then, in the *sixth step*, the global priority vector, which ranks the alternative solutions with respect to the main goal, is evaluated.

Table 2.9 Saaty scale for pairwise comparison

Intensity	Definition	Explanation
1	Equal importance	Two activities contribute equally to the objective
2	Weak	
3	Moderate importance	Experience and judgment slightly favor one activity over another
4	Moderate plus	
5	Strong importance	Experience and judgment strongly favor one activity over another
6	Strong plus	
7	Very strong or demonstrated importance	An activity is favored very strongly over another; its dominance demonstrated in practice
8	Very, very strong	
9	Extreme importance	The evidence favoring one activity over another is of the highest possible order of affirmation

Table 2.10 Random consistency index for corresponding matrix size

Matrix size	1	2	3	4	5	6	7	8	9	10
Random index	0	0	0.58	0.9	1.12	1.24	1.32	1.41	1.45	1.49

$$\begin{bmatrix} 1 & a_{12} & a_{13} & \dots & a_{1n} \\ 1/a_{12} & 1 & a_{23} & \dots & a_{2n} \\ 1/a_{13} & 1/a_{23} & 1 & \dots & a_{3n} \\ \dots & \dots & \dots & \dots & \dots \\ 1/a_{1n} & 1/a_{2n} & 1/a_{3n} & \dots & 1 \end{bmatrix} \begin{bmatrix} w_1 \\ w_2 \\ w_3 \\ \dots \\ w_n \end{bmatrix} = \lambda \begin{bmatrix} w_1 \\ w_2 \\ w_3 \\ \dots \\ w_n \end{bmatrix} \tag{2.24}$$

$$C_i = \frac{(\lambda_{max} - n)}{(n-1)} \tag{2.25}$$

$$C_R = \frac{C_i}{R_i} \tag{2.26}$$

Software Tool HOMER Energy®

The software HOMER Energy® [31] was used to evaluate the economic and environmental performances of the different IPS configurations that will be considered for the AHP process. HOMER Energy® was developed by the U.S. National Renewable Energy Laboratory (NREL) and can model the physical behaviors of micro-power systems and evaluate both their life cycle costs and their environmental impact (in terms of gasses emitted). In addition to the simulation of power systems, HOMER Energy® can also perform optimization and sensitivity analyses. HOMER Energy® can be used to model various micro-power-system configurations comprised of PV systems, wind turbines, combustion engines, river turbines and energy-storage technologies (batteries, flow batteries and flywheels). The micro-power system can be connected to the grid or operate in isolated modus. HOMER Energy® can consider both the electric and thermal loads. It can be proven through the simulation whether the micro-power system designed can supply the electric and thermal power according to the load and other constraints used by the designer. Moreover, the simulation also evaluates the life cycle costs (by evaluating the net present costs) of the system, as well as technical and environmental parameters, such as CO_2 emissions. Additionally, it can be used to compare different micro-power-system configurations to find the optimal configuration that minimizes the life-cycle costs.

Formulation of the Decision-Making Problem and Configuration of the IPS

A small IPS located in Siberia, Russia, was chosen as the case study for adopting the planning methodology developed. The IPS requires an annual electricity demand of 11,202 MWh with a maximum power demand of 3.0 MW. The highest and lowest electric power consumption occurs in winter and summer, respectively (see Fig. 2.27).

It is assumed that the electric load within the IPS was supplied by a diesel generator which, due to its age, should be replaced. The decision-makers have to evaluate

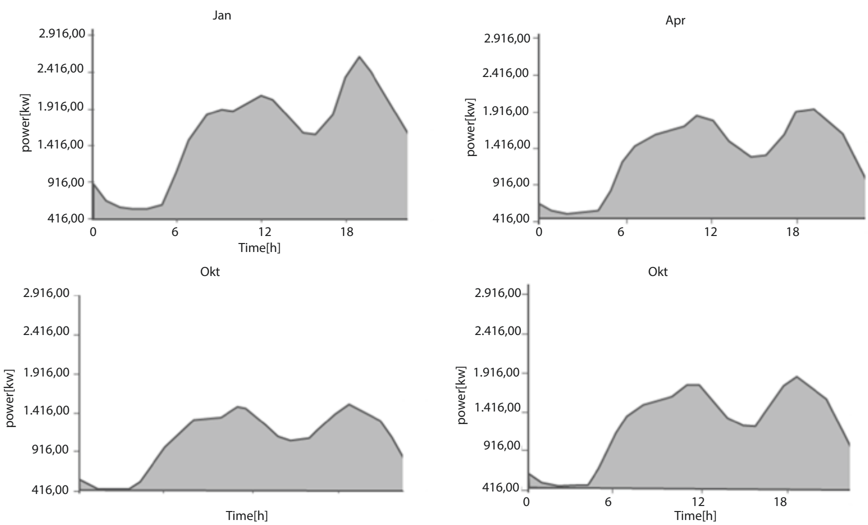

Fig. 2.27 Seasonal consumption patterns for the isolated power system analyzed

the best option (of power-system configuration) for upgrading the IPS. Three criteria will be considered by the decision-makers when selecting the best configuration: economic, ecological and social. The economic criterion is split into the investment cost (IC) and the cost of electricity (COE), while the ecological criterion is divided into CO_2, particulate matter (PM) and NO_x emissions.

The social criterion considers the creation of new jobs that can be generated by upgrading the IPS. The entire lifetime of the IPS will be considered for all the criteria. The first two criteria were evaluated using the HOMER Energy® software, while the evaluation of the social criteria is based on the technical study edited by the International Renewable Energy Agency (IRENA).

Four IPS configurations for upgrading the IPS were considered by the decision-makers: In configuration I, a diesel generator is considered as a replacement for the old one, while in configuration II the power is generated by a new diesel engine and a PV plant. Configuration III adds a storage system (battery plants) to configuration II. Configuration IV is similar to configuration III, with the additional possibility of generating electric power from wind turbines. The hierarchy structure for the best choice of the IPS is shown in Fig. 2.28.

Power Generators/Storage Characteristics and Energy Resources

The four IPS configurations considered reflect three different electric-power generation technologies and a storage system. The power-generator technologies are: diesel engine, wind turbine and PV plant, while a battery plant was considered for the energy-storage system. Such architecture does not consider the transformers used to increase and decrease the voltage before the power is transmitted and distributed to the loads. In order to integrate the power generated by the PV plant and the power discharged from the storage system into the AC network, 11–14 converters (400 Vdc–400 Vac), were considered. All the components analyzed can be selected from the library of the Homer® software.

Regarding the diesel generator, an engine with a nominal power capacity of 3200 kW and a maximal efficiency of 30 % was selected. The efficiency curve for

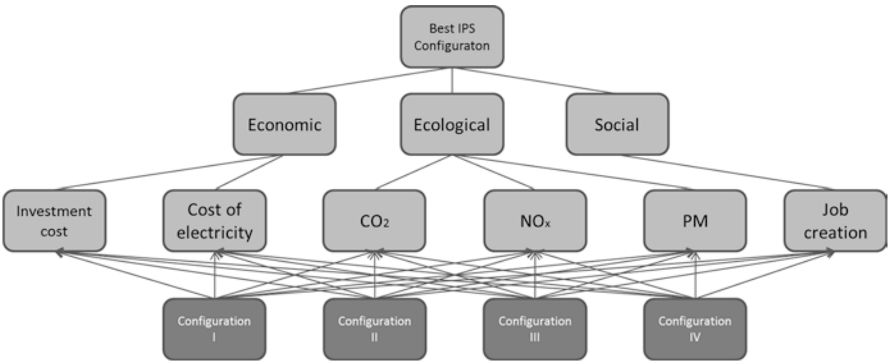

Fig. 2.28 Hierarchical structure for the choice of the best IPS configuration

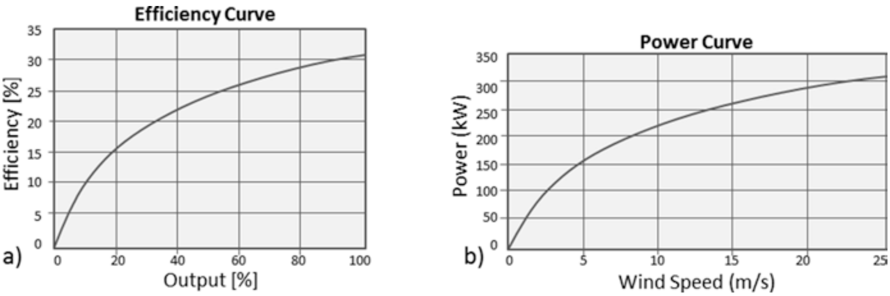

Fig. 2.29 Efficiency curve of the diesel engine (**a**); power curve of the wind turbine (**b**)

each power output of the diesel engine is shown in Fig. 2.29a. A flat plate polycrystalline PV plant without a solar tracking system and with efficiency at a standard test condition of 13 % was chosen. The Enercon E33 model was considered for the wind turbine. Such a model can generate up to 330 kW in the best meteorological conditions (see Fig. 2.29b). The battery selected has a storage capacity of 1 MWh with a maximal charge/discharge power of 1 MW and an all-round efficiency of 80 %. The technical and economical characteristics of the power generators and the storage system are shown in Table 2.11.

Table 2.11 Technical and economical characteristics of the generator and storage systems

	Diesel generator	Photovoltaic plant	Wind Turbine	Battery	Inverter
Nominal power [kW]	3200 [kW]	3200 [kW]	330 [kW]	1000 [kW]	300 [kW]
Storage capacity [kWh]				1000 [kWh]	
Number of units	1	1	1–10	1	11–14
Investment costs [€/kW]	700	2500	1515	1630	400
Maintenance & operation costs	0.1 [€/h]	100 [€/year]	2000 [€/year]	9200 [€/year]	
Lifetime	15,000 [h]	20 [years]	15 [years]	15 [years]	10 [years]
Hub height [m]			25		
Efficiency [%]	30	13		80	90
Minimal state of charge [%]				20	
Configuration I	√				
Configuration II	√	√			√
Configuration III	√	√	√		√
Configuration IV	√	√	√	√	√

Diesel-based generation is the power source most often used among the Russian IPSs. However, this energy resource is brought to the IPS via expensive transportation systems, such as boats, trucks or, in some cases, helicopters. This means that the electricity generation costs, in some cases, could reach a value ranging 500–2500 $/MWh. The integration of renewable energy sources, such as wind or sun, for these IPSs can influence the generation costs beneficially. However, the power technologies based on wind and sun are more expensive than the conventional diesel engines. Therefore, the stakeholders might have to face high investment costs in the early stage of the IPS upgrading. Added to this is the fact that the integration of a large amount of power generated by intermittent RES within autonomous systems requires energy-storage systems, which are still very expensive.

On the other hand, once everything has been set up, the use of RES and storage systems strongly decreases the operation costs of the IPS, while the reliability of the power supply increases. This is especially true when the availability of RES is high. For the particular location considered in this study, the availability of the sun and wind resources were estimated through the Atmospheric Science Data Centre of NASA. A Weibul shape factor of 2 was considered for the simulation of the power generated by the wind turbines. Based on these data, the full load hours of a wind turbine and a PV plant installed within the district of Irkutsk are 538 and 1275 h, respectively. These parameters have been used successively for sizing the PV and wind turbine plants. Figure 2.30 [Lombardi] depicts the hourly generation profiles for the PV plant and the wind park for the district of Irkutsk. Both the power plants have an installed capacity of 3000 kW.

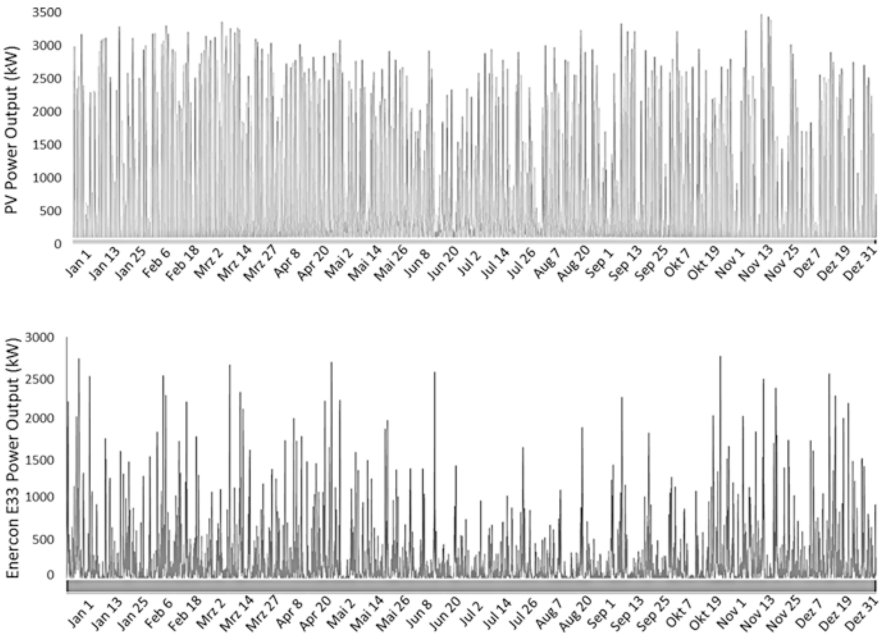

Fig. 2.30 Hourly generation profiles for the PV plant (*top*) and wind farm (*bottom*)

Analysis of Economic and Installable RES Power in the IPS Configurations
Four configurations were analyzed using the HOMER Energy® software mentioned before. The analysis consists of estimating the investment costs (IC) and the cost of electricity (COE) for each configuration. A discount factor of 6 % was considered in the calculation of the COE. HOMER Energy® is also able to identify whether the configuration modeled can cause stability problems in the electricity network.

By simulating all the IPS configurations, a diesel price ranging between 0.1 and 2.0 €/liter was considered. By only considering the cost of energy as a criterion, it could be asserted that the diesel price strongly influences the decision of whether to install a PV plant or not. Indeed, by comparing configuration II with configuration I, the investment in a PV plant (configuration II) can be justified only if the diesel price is higher than 1.7 €/liter. The maximal PV power capacity that configuration II can integrate without creating network stability problems is 600 kW. The case is different for configuration III. Here, the installation of a PV plant and a battery system is preferable if the diesel price is higher than 0.8 €/liter. Thanks to the battery system, it is possible in configuration III to integrate up to 3200 kW of PV power into the IPS. Configuration IV could only be considered if the diesel price was higher than 0.9 €/liter. The maximal number of wind turbines that is possible to integrate in configuration IV is 10, which equals 3300 kW of electric power. Table 2.12 shows the summary of the investment costs and related costs of electricity needed for each configuration analyzed, while the installed power and storage capacity for each configuration are depicted in Table 2.13.

Ecological and Social Analysis of the IPS Configurations
As previously depicted, the diesel price influences the IPS configuration strongly. The higher the diesel price, the more economically justified the use of renewable energy is. For this study, the price of 1.00 €/liter of diesel was used. The emissions of CO_2, NO_x and PM, which were evaluated by HOMER Energy®, are depicted in Table 2.14.

The job creation (JC) criterion was used to evaluate the social aspects related to the IPSs. The IRENA report was used to do this; it states that 30 and 22 new jobs could potentially be created for each MW of PV plant or wind turbine, respectively, installed and operating as an IPS in a rural area.

Sub-Criteria Weights and Evaluation of the Best IPS Configuration
Six sub-criteria in total were considered by the decision-makers to choose the best IPC configuration (see also Fig. 2.29). Since the main aim of this case study is to show how the developed framework for upgrading IPS could be used, the weighting of the criteria reflects a purely numerical application and is not related to any real project. Table 2.15 shows the pairwise comparison matrix of sub-criteria with respect to the main goal of the decision problem (choice of the optimal IPS configuration).

The pairwise comparison matrix has a consistency ratio (C_R) lower than 10 %, therefore, it could be considered as consistent. The resulting local priority vector is evaluated as follows:

$(0.2321, 0.2946, 0.0992, 0.0215, 0.0515, 03011)^T$

Table 2.12 Economic analysis of the IPS configurations

Diesel price [€/litre]	Investment cost [k€]				Cost of electricity [€/kWh]			
	Conf. I	Conf. II	Conf. III	Conf. IV	Conf. I	Conf. II	Conf. III	Conf. IV
0.1	2100	3380	3380	3380	0.293	0.302	0.302	0.302
0.2	2100	3380	3380	3380	0.337	0.346	0.346	0.346
0.3	2100	3380	3380	3380	0.38	0.389	0.389	0.389
0.4	2100	3380	3380	3380	0.424	0.433	0.433	0.433
0.5	2100	3380	3380	3380	0.468	0.477	0.477	0.477
0.6	2100	3380	3380	3380	0.512	0.521	0.521	0.521
0.7	2100	3380	13013	13013	0.555	0.564	0.56	0.56
0.8	2100	3380	13013	13013	0.599	0.608	0.594	0.594
0.9	2100	3380	13013	18013	0.643	0.652	0.627	0.625
1.0	2100	3380	13013	18013	0.687	0.696	0.661	0.655
1.1	2100	4880	13013	18013	0.73	0.738	0.695	0.684
1.2	2100	4880	13013	18013	0.774	0.781	0.729	0.714
1.3	2100	4880	13013	18013	0.818	0.823	0.762	0.743
1.4	2100	4880	13013	18013	0.862	0.865	0.796	0.773
1.5	2100	4880	13013	18013	0.906	0.907	0.83	0.802
1.6	2100	4880	13013	18013	0.949	0.949	0.864	0.83
1.7	2100	4880	13013	18013	0.993	0.992	0.897	0.859
1.8	2100	4880	13013	18013	1.037	1.034	0.931	0.888
1.9	2100	4880	13013	18013	1.081	1.076	0.965	0.917
2.0	2100	4880	13013	18013	1.124	1.118	0.998	0.946

Table 2.13 IPS Configurations

	Diesel generator [kW]	Photovoltaic plant [kW]	Battery plant [kW]; [kWh]	Number of wind turbines model Enercon E33
Configuration I	3000	–	–	–
Configuration II	3000	600	–	–
Configuration II	3000	3200	1000; 1000	–
Configuration IV	3000	3200	1000; 1000	10

Table 2.14 Emissions analysis for each configuration

	Configuration I	Configuration II	Configuration III	Configuration IV
CO_2 [tons/yr]	12,914	12,460	9959	8697
NO_x [tons/yr]	284	274	219	191
PM [tons/yr]	2.43	2.31	1.85	1.618

Table 2.15 Pairwise comparison matrix of sub-criteria

	Investment cost	Cost of electricity	CO_2	NO_x	Particular matter	Job creation
Investment cost	1	1/3	5	9	4	1
Cost of electricity	3	1	3	9	3	1
CO_2	1/5	1/3	1	9	3	1/5
NO_x	1/9	1/9	1/9	1	1/3	1/9
PM	1/4	1/3	1/3	3	1	1/9
Job Creation	1	1	5	9	9	1

$\lambda_{max} = 6.597$; CR = 0.092.

The local priority vector shows that the job creation sub-criterion is the most important of the sub-criteria and that the economic criterion is the most important among the criteria for the decision-makers. The pairwise comparison matrices to each sub-criterion and their respective local priority vectors are shown in Tables 2.16, 2.17, 2.18 and 2.19.

Table 2.16 Pairwise comparison of the IPS configuration to the investment cost sub-criterion

	Configuration I	Configuration II	Configuration III	Configuration IV	Priority vector
Configuration I	1	3	5	9	0.583
Configuration II	1/3	1	5	7	0.29
Configuration III	1/5	1/5	1	3	0.085
Configuration IV	1/9	1/7	1/3	1	0.042

$\lambda_{max} = 4.165$; CR = 0.06.

Table 2.17 Pairwise comparison of the IPS configuration to the cost of the electricity sub-criterion

	Configuration I	Configuration II	Configuration III	Configuration IV	Priority vector
Configuration I	1	3	1/5	1/8	0.0914
Configuration II	1/3	1	1/3	1/8	0.0579
Configuration III	5	3	1	1/3	0.2535
Configuration IV	8	8	3	1	0.5972

$\lambda_{max} = 4.273$; CR = 0.1.

Table 2.18 Pairwise comparison of the IPS configuration to the CO_2, NO_2 and PM sub-criteria

	Configuration I	Configuration II	Configuration III	Configuration IV	Priority vector
Configuration I	1	1/3	1/5	1/8	0.0503
Configuration II	3	1	1/3	1/8	0.0984
Configuration III	5	3	1	1/3	0.2401
Configuration IV	8	8	3	1	0.6112

$\lambda_{max} = 4.125$; CR = 0.046.

Table 2.19 Pairwise comparison of the IPS configuration to the job-creation sub-criterion

	Configuration I	Configuration. II	Configuration. III	Configuration. IV	Priority vector
Configuration I	1	1/3	1/5	1/8	0.0491
Configuration II	3	1	1/3	1/8	0.0778
Configuration III	5	3	1	1/3	0.2175
Configuration IV	8	8	3	1	0.6556

$\lambda_{max} = 4.163$; CR = 0.06.

The local priority vectors of each IPS configuration have to be multiplied by the local priority vector of the sub-criteria in order to rank the best IPS configuration (see Eq. (2.27)). Consequently, the ranking of the best IPS configuration is obtained.

In this case study, the IPS that best satisfies the decisional criteria of the decision-makers is configuration IV (48.83 % of preferences), followed by configuration III (20.12 % of preferences), configuration I (17.52 % of preferences) and, lastly, by configuration II (12.47 % of preferences).

$$\begin{bmatrix} 0.583 & 0.0914 & 0.0503 & 0.0503 & 0.0503 & 0.0491 \\ 0.29 & 0.0579 & 0.0984 & 0.0984 & 0.0984 & 0.0778 \\ 0.085 & 0.2535 & 0.2401 & 0.2401 & 0.2401 & 0.2175 \\ 0.042 & 0.5972 & 0.6112 & 0.6112 & 0.6112 & 0.6556 \end{bmatrix} \begin{bmatrix} 0.2321 \\ 0.2946 \\ 0.0992 \\ 0.0215 \\ 0.0515 \\ 0.3011 \end{bmatrix} = \begin{bmatrix} 0.1752 \\ 0.1247 \\ 0.2012 \\ 0.4883 \end{bmatrix} \quad (2.27)$$

Test Questions Chap. 2

- Have storage systems been used in the past and are they used in present power systems? For which applications?
- What are the main storage-characteristic parameters?
- What are the characteristic features for the generic storage-surface model?
- Give an example of a use case for storage. Which energy market players, in such a use case, must be taken into account?
- What are the main parameters of the mathematical model of storage?
- How can optimal storage be calculated?
- Which data are necessary for dimensioning storage in IPS systems?

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