Chapter 3
Grid Extension and Enhancement

3.1 Introduction

There are two general approaches to providing electricity access: by extending the national grid or by implementing off-grid systems. The term “grid extension” refers to the provision of electricity access by the extension or enhancement of the existing national grid. Grid extension encompasses not only constructing medium-voltage distribution lines to reach new communities but also adding new connections to households in areas with existing but incomplete electricity access.

Although this book focuses on off-grid systems, attention must be given to the grid extension approach. We consider grid extension because:

- It is the most common approach to providing electricity access;
- It can be more expeditious and cost-effective than off-grid systems at providing high-tier electricity access for communities located near existing electrical infrastructure;
- Many of the technical and economic concepts and considerations related to grid extension also apply to mini-grid systems.

Grid extension is the default electrification practice by utilities and governments. It is estimated that 99% of electricity infrastructure investments, including those that improve the quality of existing connections, go toward grid extension projects [10]. Off-grid systems are only considered when there is a compelling reason not to extend the grid to a particular community. These reasons primarily include cases in which:

- Off-grid systems are less expensive on a per connection or per unit of energy consumed basis than grid extension;
- The wait for grid extension is too long;
- The electricity access tier (see Chap. 2) provided by the grid is insufficient for the community (e.g., the grid reliability is insufficient for a health-care facility).

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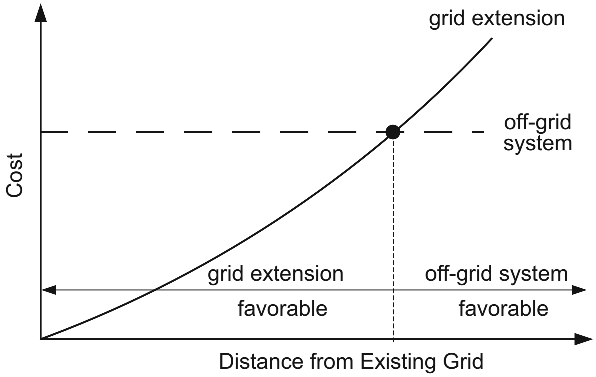

Fig. 3.1 Cost curve of grid extension and off-grid systems

Figure 3.1 shows a simplified cost curve of providing electricity access to a community as a function of distance of the community to the existing grid. The cost of grid extension and an off-grid system are shown. The cost of the off-grid system can be approximated as being constant, regardless of the distance from the grid. The cost of grid extension on the other hand rises as the distance from the grid increases. This is attributed to increased construction and material costs and losses along the line.

The two curves intersect at some distance, indicated by the dot in Fig. 3.1. To the left of the dot, grid extension is economically favorable; to the right of the dot, the cost of constructing electrical infrastructure and the associated losses make an off-grid system less expensive. This simple idea, that the distance from the grid greatly influences whether or not off-grid systems are economically favorable [2, 7, 8], is a major theme of this chapter.

3.1.1 Urban Electrification

The cost curves show that, all other considerations being equal, the most efficient use of a limited electrification budget is to connect people located near the existing electric grid through grid extension. This then biases electrification efforts to those living in urban and peri-urban areas, leaving rural, remote communities underserved. In fact, 80% of the 222 million people gaining first-time access to electricity between 2010 and 2012 lived in urban areas [9].

Increasing access in urban areas can usually be done quickly and at relatively low cost. In some regions, the per connection cost of connecting a rural household is over eight times that of an urban household [3].

Despite the focus on urban electrification, a surprisingly large number of people live within eyesight of the grid and yet have no access to it. For example, in Kenya about 50% of the 33 million people without electricity are estimated to live “under

Fig. 3.2 Millions of people live within sight of power lines but are not connected (courtesy of P. Dauenhauer)

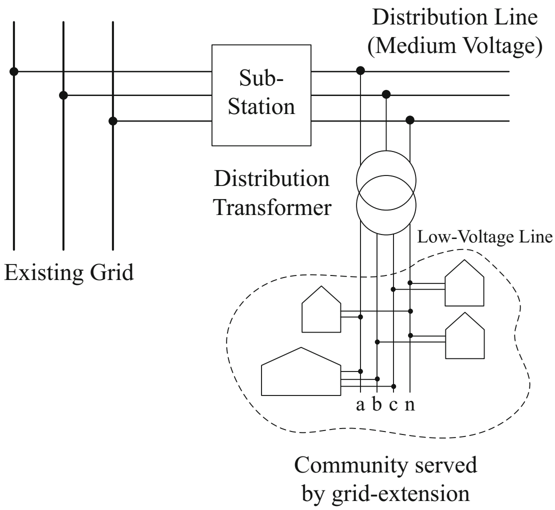

Fig. 3.3 The basic components of grid extension include substation, three-phase medium-voltage distribution line, distribution transformer, low-voltage wiring, and user premise equipment (not shown)

the grid"—within 200 m of the grid—as shown in Fig. 3.2 [6]. Across Sub-Saharan Africa (SSA), 30% of urban residents do not have access to electricity. Many of them live in slums and other informal settlements.

3.1.2 Basic Components of Grid Extension

The basic components of a grid extension project are shown in Fig. 3.3. The grid acts to connect all of the generation sources to all of the end users. These are not shown in the diagram. An existing distribution line or substation is modified so that a new distribution line can be connected to it. The distribution line is nominal voltage usually 11 kV to 33 kV. These voltage levels are commonly referred to as "medium-voltage". A transformer might be needed to change the voltage of the existing line to the nominal voltage of the new distribution line. The distribution line is typically a bare (uninsulated) overhead pole-top three-phase circuit. Once the distribution line reaches the community, a transformer reduces the voltage to the service voltage level, typically 120 or 230 V. Communities with high power consumption are served by multiple transformers. Low-voltage wiring connects the transformer secondary to the users. The home or building of each user must be internally wired and metered. In many cases, a distribution line serves several communities along its path.

3.2 Distribution Line Design

The purpose of a distribution line is to provide a pathway for power to flow from its sending end—where it is connected to the existing grid—to its receiving end, where the users are located. Distribution lines can be overhead or buried. Distribution lines to rural areas are almost always overhead as this is less expensive. A typical overhead three-phase distribution line is shown in Fig. 3.4. Overhead distribution lines are supported by poles that are 8 to 14 m tall and are made of wood, metal, concrete, or a composite material. The poles are typically spaced between 50 m and 200 m apart. The conductors are uninsulated, which increases the problems caused by falling tree branches and animals. Ceramic, glass, or polymeric insulators connect the conductors to the poles.

Fig. 3.4 A typical three-phase overhead distribution line (courtesy of R. Ngoma)

The design of a distribution line can be separated into two interrelated aspects: electrical and mechanical. The mechanical aspects include the tower or support structure, the conductor tensioning system, and the associated civil works. The electrical aspects include the selection of the conductor and insulators. Distribution line design is a rich subject and covered in other texts [4]; for our purposes, we will review the basic electrical conductor design only.

3.2.1 Power, Voltage, and Current Relationship

Before continuing with this section, the reader may wish to review the basics of three phase circuit concepts and analysis provided in the Appendix. Distribution lines consist of three phase conductors. The nominal voltage of a distribution line refers to the root mean square (RMS) magnitude of the line-to-line voltage $V_{\ell\ell}$, for example, the voltage from the a-phase conductor to the b-phase conductor. Common distribution line nominal voltages in SSA are 11 kV, 22 kV, and 33 kV. The relationship between the magnitude of the line-to-line voltage and the magnitude of the line-to-neutral voltage of a balanced three-phase system is

$$V_{\phi} = \frac{V_{\ell\ell}}{\sqrt{3}} \tag{3.1}$$

where V_{ϕ} is the nominal line-to-neutral voltage of the distribution line. Due to real and reactive losses along the line, the power supplied to the sending end (the end connected to the grid) is different from the power at the receiving end (the end located at the community). We therefore must distinguish the sending-end quantities from the receiving-end quantities. The sending-end line-to-neutral voltage and apparent power are denoted $\boldsymbol{V}_{\mathrm{s}}$ and $S_{\mathrm{total,s}}$, respectively; the receiving-end quantities are $\boldsymbol{V}_{\mathrm{r}}$ and $S_{\mathrm{total,r}}$. Keep in mind that apparent power quantities are complex, where the real part refers to the real power P, expressed in watts, and the imaginary part refers to the reactive power, Q, expressed in voltampere reactive (VAR). Generically

$$S = P + \mathrm{j}Q. \tag{3.2}$$

We will arbitrarily assume that the voltages refer to the a-phase line-to-neutral voltage. Note that variables corresponding to phasors will use bold italic font. In most cases it is reasonable to assume that the magnitude of the sending-end voltage is equal to the nominal line-to-neutral voltage $|\boldsymbol{V}_{\mathrm{s}}| = V_{\phi}$.

We can assume that each phase carries an equal amount of power so that the per-phase sending- and receiving-end apparent powers S_{s} and S_{r} are

$$S_{\mathrm{s}} = \frac{S_{\mathrm{total,s}}}{3} \tag{3.3}$$

$$S_r = \frac{S_{\text{total},r}}{3}. \tag{3.4}$$

The per-phase real power is therefore

$$P_s = |S_s| \times PF \tag{3.5}$$

$$P_r = |S_r| \times PF \tag{3.6}$$

where PF is the power factor associated with the load. A reasonable assumption is a power factor of 0.85 lagging. The a-phase line current, also expressed in RMS, is

$$\boldsymbol{I}_s = \left(\frac{S_s}{\boldsymbol{V}_s}\right)^* \tag{3.7}$$

$$|\boldsymbol{I}_s| = \frac{|S_s|}{|\boldsymbol{V}_s|} \tag{3.8}$$

where * is the complex conjugate operator. We make the approximation that the sending-end current is equal to the receiving-end current. From (3.8), we see that for a given quantity of power, there is an inverse relationship between the voltage magnitude and current magnitude. The nominal voltage of a distribution line is typically selected based upon the quantity of power it is expected to supply. For example, a utility might select 33 kV for distribution lines serving 2.5 MVA or above and 11 kV for lines serving less than 2.5 MVA. The goal of these selections is to keep the current and their resulting line losses low.

3.2.2 Distribution Line Model

A circuit model of a single phase of a distribution line is shown in Fig. 3.5. This model ignores the capacitive affects that become increasingly important as the length exceeds about 50 km. The conductor is modeled as a resistance R_{line} in series with a inductive reactance X_{line}. The impedance of a conductor in a distribution line is

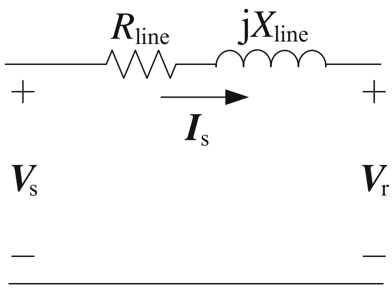

Fig. 3.5 Distribution line circuit model

$$Z_{\text{line}} = R_{\text{line}} + jX_{\text{line}}. \tag{3.9}$$

3.2.2.1 Resistance

The AC resistance R_{line} between the sending and receiving end of each conductor in a distribution line depends on the length, cross-sectional area, frequency, and material used:

$$R_{\text{line}} = s\rho \frac{l}{A_{\text{line}}}. \tag{3.10}$$

Here ρ is the resistivity in ohmmeters, l is the conductor length in meters, and A_{line} is the conductor cross-sectional area in meters squared. The coefficient s models the frequency-dependence of resistance caused by the skin effect. The skin effect increases the resistance by about 1–3% in a 50 Hz distribution line.

The resistivity is a property of the conductor material, which is typically aluminum or an aluminum alloy. Note that distribution lines are not always constructed along the shortest geographic path between two points, and so the length of a proposed line can be considerably longer than the distance between a community and the existing grid.

3.2.2.2 Inductive Reactance

In addition to resistance, distribution lines have significant inductive effects. Deriving the series inductive reactance of a conductor is beyond the scope of this book but can be found in most power system analysis textbooks [1]. It suffices to note that the inductance L of one of the phases of the distribution line depends on a variety of factors: the length of the line, the physical distance separating the phases, and the effective radius of the conductors. The inductive reactance, X_{line}, is computed from

$$X_{\text{line}} = \omega L \tag{3.11}$$

where ω is the frequency of the system, in radians per second.

The relationship between conductor radius and inductive reactance for three different separation distances is shown in Fig. 3.6a. Decreasing the separation distance reduces the inductive reactance. However, the separation cannot be made arbitrarily small. The conductors must be spaced far enough apart to prevent arcing or accidental contact. Increasing the conductor radius reduces the inductive reactance. It also decreases the resistance. The separation distance has no effect on resistance. The inductive reactance for a given conductor and separation distances are provided by conductor's manufacturer.

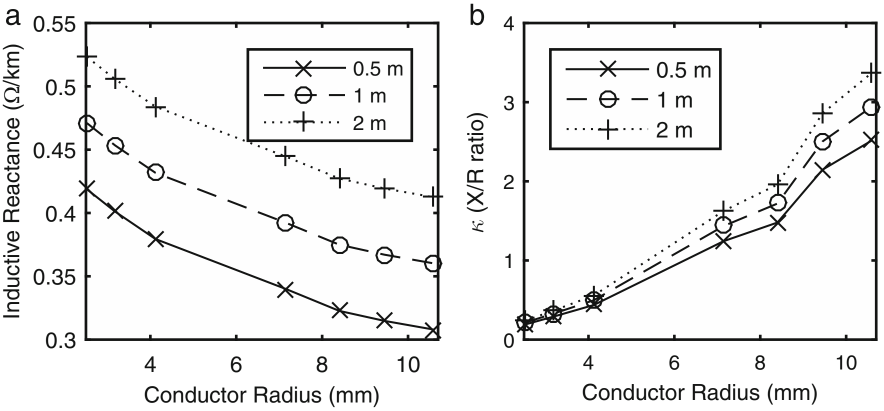

Fig. 3.6 (**a**) The effect of conductor radius on the inductive reactance per kilometer. (**b**) The X/R ratio for various conductor separation distances

It is often convenient to express the ratio of the inductive reactance to the resistance by the so-called X/R ratio κ:

$$\kappa = \frac{X_{\text{line}}}{R_{\text{line}}}. \tag{3.12}$$

The resistance is more sensitive to changes in the conductor radius than the inductance, so κ increases with the radius, as shown in Fig 3.6b.

3.2.3 *Constraints*

There are two important technical limitations that must be considered in designing a distribution line. The first is the voltage drop along the line, which restricts how long a distribution line of a given conductor radius can be. The second is the thermal limit of the line, which restricts the amount of current that can flow through the conductor, regardless of its length. The thermal limit is associated with the power loss along the line. The voltage drop and power loss are related, but not the same.

Selecting a conductor with a larger cross-sectional area reduces the voltage drop and increases the maximum current-carrying capability. Of course, the conductor cross-sectional area cannot be made arbitrarily large as it will be more expensive, require more mechanical support, and be more challenging to install.

3.2.3.1 Voltage Drop

The voltage drop of a distribution line is the magnitude of the difference between the voltage at the sending end and the receiving end. In general, the voltage drop should not exceed 5 to 10 % of the line's nominal line-to-neutral sending-end voltage. Large voltage drops result in low voltage at the receiving end. This can damage the users' appliances and equipment or cause them to malfunction.

The magnitude of the voltage drop depends on the amount of current and the length of the line. The maximum length that a line can be without violating a voltage drop limit for a specified amount of current is known as the "voltage reach" of the line. For example, if at a current of 180 A, the voltage along a distribution line decreases by 2.5% per kilometer, then the voltage reach of the line is four kilometers using a 10% voltage drop limit. The voltage reach would be increased if the current is decreased.

The magnitude of the voltage drop $V_{\text{drop},\phi}$ along a phase of a distribution line is

$$V_{\text{drop}} = |\boldsymbol{V}_{\text{s}} - \boldsymbol{V}_{\text{r}}| = |\boldsymbol{I}_{\text{s}}| \times |Z_{\text{line}}|. \tag{3.13}$$

The voltage drop expressed as a percent is

$$V_{\text{drop},\%} = \frac{V_{\text{drop}}}{|\boldsymbol{V}_{\text{s}}|} \times 100. \tag{3.14}$$

Example 3.1 The conductors used in a 33 kV distribution line have an impedance of $Z_{\text{line}} = 1.75 + \text{j}1.0\ \Omega$. The magnitude of the line current is 115 A. Compute the voltage drop as a percent.

Solution Each phase of the distribution line carries 115 A, and so the voltage drop is computed using (3.13) as

$$V_{\text{drop}} = 115 \times |1.75 + \text{j}1.0| = 231.79\ \text{V}.$$

We will make the standard assumption that the sending end is at the nominal voltage. The nominal voltage of the distribution line is always given as a line-to-line value. The corresponding line-to-neutral voltage is found using (3.1) to be

$$V_\phi = V_{\text{s}} = \frac{33{,}000}{\sqrt{3}} = 19052.6\ \text{V}$$

The percent drop is found from (3.14)

$$V_{\text{drop},\%} = \frac{231.79}{19052.6} \times 100 = 1.22\%.$$

This is below the typical 5–10% maximum voltage drop.

Should the length of a distribution line be limited by the voltage reach, the designer has several options:

- use conductors with larger cross-sectional area to reduce the resistance and inductive reactance;
- decrease the separation distance between the conductors to reduce the inductive reactance;
- increase the nominal voltage of the distribution line to reduce the current for a given amount of power;
- include voltage boosting equipment such as transformers or capacitor banks.

With the exception of decreasing the separation distance, these options increase the cost of the distribution line.

3.2.3.2 Thermal Limit

The current that a conductor can carry continuously is limited by its thermal characteristics. Heat is generated as current flows along the conductor due to the conductor's resistance. The generated heat is considered a power loss. The power loss along each phase and the total power for the line are computed as

$$P_{\mathrm{loss},\phi} = |\boldsymbol{I}_{\mathrm{s}}|^2 \times R_{\mathrm{line}} \tag{3.15}$$

$$P_{\mathrm{loss,total}} = 3P_{\mathrm{loss},\phi}. \tag{3.16}$$

It is possible for the heat generated by the power loss to increase the temperature of the conductor beyond the acceptable level, causing it to anneal and mechanically fail. The amount of current that can flow continuously through a line without overheating is known as the "ampacity" of the line. Note that the current through each phase has equal magnitude. The ampacity of a conductor is therefore the same as the ampacity of the line. The ampacity for a given conductor depends on the heat generated by the current in the conductor, the ambient temperature, the heat from the sun, and the cooling caused by the wind.

The ampacity of a conductor under typical conditions is provided by the manufacturer. The ampacity is not a strict limit because the conditions governing the temperature of the line, for example, the ambient temperature, vary over the course of a day and throughout the year. Some utilities will allow a distribution line to carry current in excess of the ampacity limit during the colder winter months.

The losses along a distribution line lower its efficiency. A utility might opt for a larger conductor than the one that satisfies the voltage drop and thermal limits in an effort to reduce the energy loss. A compromise must be made: increasing the cross-sectional area reduces losses but also increases the cost of the line.

3.2.4 Conductor Sizes and Types

Manufacturers produce a wide range of conductors for use in distribution lines. There are several conventions for expressing the cross-sectional area of a conductor: in square millimeters, circular mils[1], and by wire gauge.

In practice, a utility might only use certain discrete sizes of conductors, for example, 50 mm^2, 100 mm^2, or 200 m^2. Several conductors can be run in parallel for each phase to decrease the effective resistance, reduce losses, and increase the total ampacity of the line.

Overhead distribution conductors are often of the type AAAC (all aluminum alloy conductor) or ACSR (aluminum conductor steel reinforced). ACSR cables are made from several aluminum conductors that are wrapped around steel cables. The steel provides tensile strength; the aluminum provides a low-resistance conduction path.

3.2.5 Distribution Line Power Rating

The apparent power rating of a distribution line is expressed in kilovolt–amperes (kVA) or megavolt–amperes (MVA). The rating corresponds to the maximum apparent power that can be supplied by the line at the nominal voltage while remaining within the thermal limits of the line. The rating of a three-phase line S_{rated} is three times the phase capacity

$$S_{\text{rated,total}} = 3 \times I_{\text{amp}} \times V_{\phi} \tag{3.17}$$

where I_{amp} is the rated ampacity of the conductor. Recall that V_{ϕ} is the nominal line-to-neutral RMS voltage of the line. The thermal rating is independent of line length, and so it ignores voltage drop limitations of the line. Obviously, though, voltage drop is an additional consideration in sizing conductors.

Example 3.2 The conductors of a 15 km long, 22 kV distribution line have a cross-sectional area of 100 mm^2. The conductors have a resistivity of 0.274 Ω/km and are spaced so that $\kappa = 1.2$. The ampacity is 313 A. Compute the power rating of the line, the voltage drop, and the losses when operating at the rated ampacity.

(continued)

[1]A circular mil is the area of a circle whose diameter is one thousandth of an inch.

Solution The power rating of the line is

$$S_{\text{rated,total}} = 3 \times I_{\text{rated}} \times V_{\phi} = 3 \times 313 \times \frac{22\text{ kV}}{\sqrt{3}} = 11.93\text{ MVA}.$$

The impedance of each conductor is

$$Z_{\text{line}} = R_{\text{line}} + \mathrm{j}X_{\text{line}} = 0.274 \times (1 + \mathrm{j}\kappa) \times 15 = 4.110 + \mathrm{j}4.932\ \Omega.$$

When operating at the rated ampacity, the voltage drop is

$$V_{\text{drop}} = I_{\text{rated}} \times |Z_{\text{line}}| = 313 \times |4.110 + \mathrm{j}4.932| = 2.009\text{ kV}$$

and the power loss for the line, accounting for all phases:

$$P_{\text{loss,total}} = 3 \times I_{\text{rated}}^2 \times R_{\text{rated}} = 3 \times 313^2 \times 4.101 = 1.208\text{ MW}.$$

We note that the line-neutral voltage at the sending end is $\frac{22\text{ kV}}{\sqrt{3}} = 12.702\text{kV}$, and the line-to-neutral voltage at the village end of the line is $12.702-2.009 = 10.692$ kV. The voltage drop therefore exceeds the typical 5% target. It can be shown that the distribution line can only supply 98.8 A per conductor without violating the voltage drop target, effectively reducing the capability of the line. Verifying this result is left to the reader.

Example 3.3 A cluster of villages is to be supplied by a three-phase distribution line that is 25 km in length. The peak load is predicted to be 3.4 MW with a power factor of 0.85 lagging. This is expected to grow by 2% per year for the next 10 years. Assume the receiving-end line-to-line voltage is 22 kV and the voltage drop limit is 10%. The conductors are separated by 2 m. The choice of conductors are shown in Table 3.1. Select the conductor with the smallest cross-sectional area that satisfies the thermal and voltage limits.

Solution The load after 10 years of 2% of growth per year is

$$P_{\text{total}} = 3.4 \times (1 + 0.02)^{10} = 4.145\text{ MW}.$$

Applying (3.3) and (3.5) to find the required per-phase apparent power rating

$$S_{\text{rated}} = \frac{P_{\text{total}}}{3} \times \frac{1}{0.85} = 1.625\text{ MVA}.$$

(continued)

The current magnitude when supplying the rated power at the nominal line-to-neutral voltage is calculated:

$$I_{\text{rated}} = \frac{S_{\text{rated}}}{|V_{\phi}|} = \frac{1.625 \text{ MVA}}{12.702 \text{ kV}} = 127.96 \text{ A}.$$

Consulting Table 3.1, the first two conductors are eliminated as the required current exceeds their ampacity. The next largest conductor (C) is checked to see if it satisfies the voltage drop limit.

$$\begin{aligned} Z_{\text{line}} = (0.869 + \text{j}0.484) \times 25 &= 21.73 + \text{j}12.10\ \Omega \\ V_{\text{drop}} &= I_{\text{rated}} \times |Z| = 3.182 \text{ kV} \\ |\boldsymbol{V}_{\text{s}}| &= |\boldsymbol{V}_{\text{r}}| + V_{\text{drop}} = 15.884 \text{ kV} \\ V_{\text{drop},\%} &= \frac{V_{\text{drop}}}{|\boldsymbol{V}_{\text{s}}|} \times 100 = 20.03\% \end{aligned}$$

Although this conductor satisfies the thermal constraint, the maximum allowable voltage drop is exceeded. The next conductor is considered and its voltage drop is calculated. This process repeats until a conductor that satisfies both the voltage and thermal constraints is identified. It can be shown that conductor G satisfies these constraints. This conductor is operating far below its rated ampacity of 590 A.

Table 3.1 Conductor characteristics

	Size (mm^2)	Ampacity (A)	Resistance (Ohm/km)	Reactance (0.5 m spacing) (Ohms/km)	Reactance (1 m spacing) (Ohms/km)	Reactance (2 m spacing) (Ohms/km)
A	13.3	95	2.200	0.419	0.471	0.523
B	21.1	125	1.384	0.401	0.453	0.506
C	33.6	165	0.869	0.379	0.432	0.484
D	107.2	325	0.273	0.340	0.392	0.445
E	135.2	415	0.218	0.323	0.375	0.427
F	201.4	525	0.147	0.318	0.367	0.423
G	241.7	590	0.122	0.308	0.360	0.413

Fig. 3.7 Pole-mounted three-phase distribution transformer in Kenya (courtesy of author)

3.2.6 Transformer Ratings

Once the distribution line reaches the community, the voltage is reduced by using a transformer. Distribution transformers are often pole-mounted, as shown in Fig. 3.7.

The primary side of the transformer must be compatible with the receiving-end voltage of the distribution line. The secondary line-to-line voltage is usually 400 V so that the single-phase voltage supplied to the users is approximately 230 V. There are other configurations, which will be discussed in Sect. 12.7.4.

The transformer must also be capable of supplying the required apparent power to the users. The rated power of a transformer is based on the power it can provide without overheating. Overheating is a concern because it reduces the lifespan of transformers. Transformers can exceed their ratings for a short period of time. However, the secondary voltage will be reduced during these periods, and the lifespan will be somewhat shortened as the transformer's insulation degrades more rapidly at higher temperatures. In the context of rural electrification, 25 kVA, 50 kVA, and 100 kVA transformers serving multiple users are commonly used.

3.2.7 Low-Voltage Connections

The connection from the low-voltage side of the transformer to the user's home or business is commonly referred to as the "service connection" or "service drop." There are two common topologies for the low-voltage connections. The "European" style uses three-phase distribution transformers. In the "American" style, each phase of the distribution line is connected to another conductor, known as a lateral. Single-phase, center-tapped transformers are connected between the lateral and the distribution line neutral, and users are provided a three-wire service of 120/240 V. This is also known as "split phase." The European style is more common in SSA. We will discuss the advantages and disadvantages of each topology in Chap. 12.

3.3 Infrastructure Cost Model

Grid extension projects are expensive. This is the primary reason that more communities do not have access to electricity. There are three costs associated with building and using an electrical system: construction, operation, and financing. We will consider the first two because they are engineering related. The construction cost can be split into five parts:

1. distribution (medium-voltage) line cost
2. low-voltage line cost
3. transformer cost
4. substation cost
5. user premise equipment (UPE) cost (meters, wiring, outlets, switches, etc.)

Many of these, particularly low-voltage line, transformer and UPE costs are also particularly relevant to off-grid systems. In developing countries in general, the cost of materials tends to dominate the cost of labor, design, and management. The cost for each aspect of grid extension can vary widely across and within countries [2, 5]. Most of the materials must be imported, so the costs are sensitive to foreign exchange rates, import duties, and logistics costs. The standard engineering and construction practices of a particular utility to only utilize components of a certain grade or from a preferred supplier can also influence the costs.

Tables 3.2 and 3.3 show the costs, including material, transportation, and installation, for various components as estimated by the Ghanaian and Zambian rural electrification master plans, respectively. Keep in mind that the actual cost of grid extension can vary substantially from those shown.

3.3.1 Distribution Line Cost

The cost of constructing a distribution line c_{line} can be estimated from its length and capacity:

$$c_{\text{line}} = \beta_{\text{line}} \times l_{\text{line}} \times S_{\text{rated,total}} \tag{3.18}$$

where l_{line} is the length of the distribution line, $S_{\text{total,rated}}$ is the rating of the line in megavoltamps, and β_{line} is the cost per MVA/km. The value of the coefficient β_{line}

Table 3.2 Costs from Ghana National Electrification Scheme Master Plan (2010)

Item	Description	Cost
33 kV line	Wood pole, 120 mm^2 conductors	US$26,222/km
11 kV line	Wood pole, 120 mm^2 conductors	US$24,690/km
200 kVA transformer	33/0.4 kV w/accessories	US$16,253
100 kVA transformer	33/0.4 kV w/accessories	US$13,815
50 kVA transformer	33/0.4 kV w/accessories	US$11,851
200 kVA transformer	11/0.4 kV w/accessories	US$13,344
100 kVA transformer	11/0.4 kV w/accessories	US$11,529
50 kVA transformer	11/0.4 kV w/accessories	US$10,243
Low-voltage line	3-phase, 4-wire, wood pole	US$16,597/km
Low-voltage line	1-phase, 3-wire, wood pole	US$14,869/km
Low-voltage line	1-phase, 2-wire, wood pole	US$12,958/km
3-phase user connection	Meter, 25 mm^2 conductor	US$531
1-phase user connection	Meter, 16 mm^2 conductor	US$275

Table 3.3 Costs from Zambia Rural Electrification Authority Master Plan (2005) [5]

Item	Description	Cost
33 kV line	pole, 100 mm^2 conductor w/accessories	US$36,000/km
100 kVA transformer	33/0.4 kV	US$13,700
2.5 MVA substation	–	US$600,000
5 MVA substation	–	US$800,000
10 MVA substation	–	US$1,000,000
15 MVA substation	–	US$1,300,000
33 kV bay	–	US$99,300

varies widely. In general, it ranges between US$1200 and US$6600 per MVA km in developing countries. Some of this variation is due to the design of the distribution line poles, which comprise up to 40% of the total material cost. Pole costs can be reduced by using shorter poles or fewer poles (by increasing the span between the poles). Higher-voltage lines also tend to have lower β_{line} values.

Example 3.4 A 33 kV distribution line is 10 km long. Each conductor has a cross-sectional area of 120 mm^2 with ampacity of 350 A. Compute the rating of the line and the total cost using $\beta_{\text{line}} = \text{US\$}1{,}300/\text{MVAkm}$.

Solution The rating of the line is found using (3.17):

$$S_{\text{line}} = 3 \times 350 \times \frac{33{,}000}{\sqrt{3}} = 20.005 \text{ MVA}.$$

(continued)

The total cost of the line is found from (3.18):

$$c_{\text{line}} = 1300 \times 10 \times 20.005 = \text{US\$}260{,}067.43.$$

This is for the line only. There are still other costs that should also be considered.

If the capacity of the line is not specified, a more general model can be used:

$$c_{\text{line}} = \beta_{\text{line,km}} \times l \tag{3.19}$$

where $\beta_{\text{line,km}}$ is cost per kilometer, which ranges from US$3,000 to over US$30,000/km. The lowest cost is found in India. The low cost has been attributed to the use of domestically manufactured components and short, prestressed concrete poles. In SSA, a cost of US$20,000/km is more typical. Although these costs are high, they are generally less expensive than in the United States, where labor and land costs can be substantially higher than in developing countries.

3.3.2 Low-Voltage Line Cost

Low-voltage lines are needed to connect the transformer secondary to the user. The lines are insulated and can be comprised of two, three, or four wires, depending on the service provided to the user. The cost of the low-voltage line can be modeled as

$$c_{\text{LV}} = \beta_{\text{LV}} \times l_{\text{LV}}. \tag{3.20}$$

The cost coefficient β_{LV} typically ranges from US$10,000 to US$18,000/km. The total length of the low-voltage lines depends on the number of users and their proximity to the transformer and each other.

3.3.3 Transformer Cost

The cost of a transformer is largely driven by its power rating. A simple cost model is

$$c_{\text{xmfr}} = \beta_{\text{xfmr}} \times S_{\text{rated,xmfr}} \tag{3.21}$$

where β_{xfmr} is the cost per kilovolt–ampere and $S_{\text{rated,xmfr}}$ is the rating of the transformer in kilovolt–amperes. Typical values of β_{xfmr} range from US$100 to US$500/kVA. The cost per kilovolt–ampere tends to decrease as the transformer size increases and as the primary voltage decreases.

Example 3.5 A community with 203 households will be served through grid extension. The 33 kV distribution line serving the community will be 12 km long. The peak apparent power of the community is estimated to be 165 kVA. Determine the minimum quantity of 50 kVA transformers needed at the community, assuming the power factor is 0.85. Compute the total transformer cost using the values found in Table 3.2.

Solution The number of 50 kVA transformers required is 165/50 = 3.3, which we round up to 4. The total transformer cost is

$$c_{\text{xfmr}} = 4 \times 11{,}851 = \text{US\$47,404.00}.$$

3.3.4 Substation Cost

The sending end of the distribution line must be connected to the existing grid. In some circumstances, it can be connected directly to an existing distribution line of the same voltage. In many cases, however, a substation must be added or an existing substation modified to accommodate the new line. The substation costs can include switching components and protective equipment and also the cost of land and civil works. The cost of a new substation is related to the rating of the line or lines it serves. However, some of the cost can be considered fixed for a reasonable range of ratings. Therefore, a cost model of the form

$$c_{\text{sub}} = \alpha_{\text{sub}} + \beta_{\text{sub}} S_{\text{sub}} \tag{3.22}$$

is appropriate, where S_{sub} is the power rating of the substation. We will assume the rating of the substation is equal to that of the line. Using the Zambian costs in Table 3.3, the coefficients α_{sub} and β_{sub} are US\$490,000 and US\$53,600/MVA, respectively. If the substation only requires modification, then the cost is considerably reduced. For example, a 33 kV substation bay is US\$90,000 in the Zambian rural electrification master plan.

3.3.5 User Premise Equipment Cost

User premise equipment includes meters, wiring, and other equipment such as circuit breakers and outlets. These costs are also incurred for mini-grid users. A meter is needed to measure energy consumption so that users can be billed properly. Although increasingly rare, some users in developing countries pay a fixed fee—their consumption is not tied to usage. While this saves the cost of installing, maintaining, and reading meters, it tends to encourage waste and excess consumption.

The cost of a meter depends upon its functionality. Premiums are paid for tamper-proofing, prepay functionality, and meters with smart capabilities. The cost of a meter generally does not vary appreciably with the power rating—at least at levels typically used by rural consumers.

UPE costs also include the cost of wiring the premises of new users. Protection devices such as circuit breakers or fuses must be installed, as well as electrical sockets (outlets), lighting receptacles, and the wiring within the house.

The total user premise equipment cost is proportional to the total number of users served N_{user} and is modeled as

$$c_{\text{UPE}} = \beta_{\text{UPE}} \times N_{\text{user}}. \tag{3.23}$$

Again, the cost coefficient can widely vary, but generally ranges from US\$90 to US\$420 per user. In some situations, the utility provides a panel that includes a meter, a socket, and perhaps a light bulb. The panel is designed so that it can be easily attached to a wall on the interior of the user's premise, reducing or avoiding the need for additional wiring.

3.3.6 Cost Per Connection

The total infrastructure cost of a grid extension project is

$$c_{\text{grid}} = c_{\text{line}} + c_{\text{LV}} + c_{\text{xmfr}} + c_{\text{sub}} + c_{\text{UPE}}. \tag{3.24}$$

We are also interested in the cost per connection. The cost per connection is found by

$$c_{\text{con}} = \frac{c_{\text{grid}}}{N_{\text{user}}}. \tag{3.25}$$

The cost per connection is useful in comparing different grid extension projects. The cost per connection can vary widely but is typically within the bounds of US\$500 to US\$5000 [3].

Example 3.6 Compute the total and per connection cost of connecting the community in Example 3.5 by grid extension. Assume that 2.5 km of single-phase low-voltage line is needed to connect the households in the community. A new 33 kV substation bay, costing US\$90,000, is required. Use Table 3.2 for all other costs.

(continued)

Solution Applying (3.24), the total cost is

$$
\begin{aligned}
c_{\text{grid}} &= \text{US\$}26{,}222 \times 12 + \text{US\$}12{,}958 \times 2.5 + \text{US\$}47{,}404 + \text{US\$}90{,}000 \\
&\quad + \text{US\$}275 \times 203 \\
&= \text{US\$}540{,}288.00.
\end{aligned}
$$

The cost per connection is found using (3.25) to be US\$2661.52.

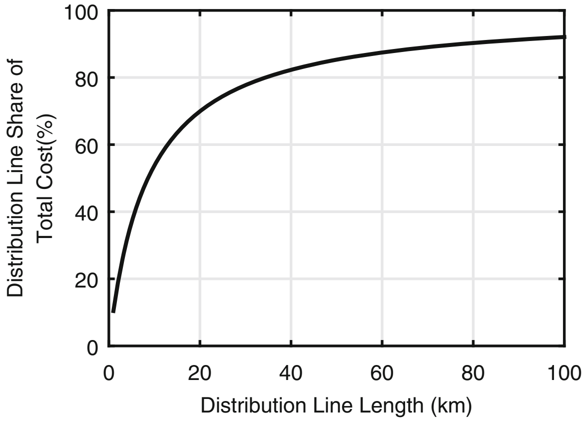

Fig. 3.8 The share of the upfront grid extension costs are increasingly dominated by the distribution line as its length increases

The total cost of a grid extension project and cost per connection are especially sensitive to the length of the distribution line, which can easily be the single greatest cost. Figure 3.8 shows the cost per connection of Example 3.5 as a function of line length. Not reflected in Fig. 3.8 is that as line length increases, larger, more expensive conductor and/or voltage support equipment are required due to the limited voltage reach. This further increases the cost of long distribution lines. The loss along a distribution line also increases with length. The cost associated with losses are not reflected in (3.25).

In terms of infrastructure costs, it is more favorable to connect communities that require short distribution lines. In many countries, grid extension is not considered to be economically viable for communities more than 20 km from the grid.

3.3.7 *Lifetime Cost of Grid Extension*

The total cost of grid extension must also include maintenance and replacement costs. The total cost over the lifetime of the equipment is

$$c_{\text{grid,life}} = c_{\text{grid}} + t_{\text{grid}} \times m_{\text{grid}} \times c_{\text{grid}} \tag{3.26}$$

where t_{grid} is the lifespan of the grid extension, in years, and m_{grid} is the annual maintenance cost of the extension, often expressed as a percent of the initial capital. This calculation ignores the time value of money, that is, a dollar today is worth more than a dollar tomorrow or a year from now, due to inflation and other factors.

To account for the time value of money, consider an annual interest rate i (which we will also refer to as the *discount rate*). The value of a sum of money V_0 after 1 year is

$$V_1 = V_0(1+i) \tag{3.27}$$

and after Y years

$$V_Y = V_0(1+i)^Y. \tag{3.28}$$

We see that $V_Y > V_0$ as long as the interest rate is greater than zero. Equation (3.28) can be rearranged to find the *present value* or *present cost* of a future an income or expense.

As an example, if US$1000 must be paid for maintenance in 5 years and assuming a discount rate of 4 %, then solving for V_0 in (3.28) yields a present cost of US$821.93. In other words, US$821.93 today is worth US$1000 in 5 years.

For a given stream of fixed payments (an annuity) or expenses of V_{annual} over Y years, the present value is

$$V_0 = V_{\text{annual}} \frac{(1+i)^Y - 1}{i(1+i)^Y}. \tag{3.29}$$

Example 3.7 The present cost of a grid extension project is US$100,000. Compute the fixed annual payment equivalent of this cost over a 20-year period at a discount rate of 5%.

Solution The present cost is known and we are asked to find the fixed annual payment. We must rearrange (3.29) to solve for V_{annual}:

$$V_{\text{annual}} = V_0 \frac{i(1+i)^Y}{(1+i)^Y - 1} = 100{,}000 \frac{0.05(1+0.05)^{20}}{(1+0.05)^{20} - 1} = \text{US\$8024.26}$$

We note that the total sum paid over 20 years is $20 \times 8024.26 =$ US$160,485.20.

Since the maintenance costs of grid extension are modeled as a fixed yearly cost over the life of grid extension, the present cost is

$$c_{\text{grid},0} = c_{\text{grid}} + m_{\text{grid}} \times c_{\text{grid}} \frac{(1+i)^Y - 1}{i(1+i)^Y}. \tag{3.30}$$

From this equation, we see that the maintenance costs, in terms of present dollars, decreases over time.

We can convert the present infrastructure cost of a grid extension project $c_{\text{grid},0}$ into Y fixed annual payments of

$$c_{\text{grid,annual}} = \frac{c_{\text{grid},0}}{\frac{(1+i)^Y - 1}{i(1+i)^Y}} \tag{3.31}$$

expressed in present dollars.

Example 3.8 Compute the present cost, fixed annual cost, and fixed annual cost per connection of the grid extension in Example 3.6. Assume the lifespan of the equipment is 30 years, the interest rate is 3%, and the annual cost of maintenance is 1% of the capital cost.

Solution Applying (3.30) yields a present cost of

$$\begin{aligned} c_{\text{grid},0} &= \text{US\$}540{,}288.00 + 0.01 \times \text{US\$}540{,}288.00 \frac{(1+0.03)^{30} - 1}{0.03(1+0.03)^{30}} \\ &= \text{US\$}646{,}186.83. \end{aligned}$$

The fixed annual cost is found using (3.31)

$$c_{\text{grid,annual}} = \frac{\text{US\$}646{,}186.83}{\frac{(1+0.03)^{30}-1}{0.03(1+0.03)^{30}}} = \text{US\$}32{,}967.97$$

which is equivalent to US\$32,967.97/203 $=$ US\$162.40 per connection per year. In other words, US\$162.40 must be collected from each user each year for 30 years to pay for grid extension.

3.3.8 *Cost of Energy in Sub-Saharan Africa*

There, of course, is a cost associated with producing the energy that is consumed by the users. Unfortunately, the cost in Sub-Saharan Africa tends to be higher than the world average. The production costs in Africa as a whole have been estimated to be US\$0.18/kWh [11]. However, this varies widely, depending on each country's generation resource mix and access to energy sources. In Southern Africa, the costs are estimated to average US\$0.13/kWh and in northern Africa US\$0.24/kWh [7].

There are several reasons for higher-energy costs in Africa. For example, financing costs can be higher due to the perception of greater risk of investments in developing countries due to political and regulatory instability. Improper maintenance and operation can reduce the total production of a power plant, causing the annual cost to be spread across a smaller base of production. The majority of electricity generated in Africa is from thermal fossil-fuel power plants. Thermal-based generators are more efficient at larger capacities. However, power plants in Africa tend to be of a smaller scale than those in other parts of the world, which increases the relative fuel costs. Aging infrastructure increases system losses, which in turn increases the cost to serve each unit of energy. Despite all this, the cost of energy from a large-scale, grid-connected power plant is in almost all cases lower than that of energy supplied by off-grid systems.

The cost of energy is often expressed as the *levelized cost of energy* (LCOE) or *simplified levelized cost of energy* (sLCOE), in dollars per kilowatthour. We will discuss LCOE in detail in Chap. 12; for now, it suffices to note that the LCOE and sLCOE are the price that must be charged for the power plant to financially break even, including the capital costs, fuel costs, maintenance, etc., as well as the time value of money. We will assume that the cost of energy is expressed in LCOE. Note that LCOE can also be calculated for off-grid systems.

3.4 Electrification Cost by Grid Extension

We are now prepared to compute the cost of serving a community through grid extension. The total annual cost consists of two parts: the energy cost, found by multiplying the per kilowatthour energy costs by the annual energy consumption E_{annual}, inclusive of losses, and the annual lifetime cost of the physical grid extension project

$$c_{\text{total,annual}} = LCOE \times E_{\text{annual}} + c_{\text{grid,annual}}. \tag{3.32}$$

The resulting cost can be used to compare electrification by grid extension with competing electrification options.

Example 3.9 Compute the cost of electrifying the village in Example 3.5, assuming the annual consumption is 365 kWh per user per year and the losses are 10%. Assume the LCOE is US$0.15/kWh.

Solution First compute the annual energy consumption:

$$E_{\text{annual}} = 365 \times 203 \times 1.10 = 81{,}504.50 \text{ kWh}.$$

(continued)

Recall from Example 3.8 that the annual infrastructure cost for this village is US$32,967.97. The annual cost is found using (3.32):

$$\begin{aligned} c_{\text{total,annual}} &= \text{US\$0.15/kWh} \times 81{,}504.50\,\text{kWh} + \text{US\$32,967.97} \\ &= \text{US\$45,193.65} \end{aligned}$$

which is equivalent to US$45,193.65/203 = US$222.63 per connection.

3.5 Comparing Electrification Options

There are options to providing access to electricity other than grid extension, for example, off-grid diesel generator sets or solar-powered systems. On the one hand, grid extension is desirable because the LCOE from the grid-connected power plants is usually far lower than for off-grid solutions; however, off-grid solutions do not require the heavy investment in distribution infrastructure. Which is the preferred option? The answer depends on a variety of community- and country-specific factors, some of which can only be estimated. However, we can at least gain insight into this question using the framework we developed.

Two critical factors in determining whether or not a grid extension or off-grid approach is most economical are the total energy consumed and the distance of the community from the grid. As the distance increases, off-grid solutions become cost-effective; as the load increases, grid extension becomes cost-effective.

To illustrate these relationships, consider Fig. 3.9. Here, the annual cost per connection, inclusive of infrastructure and energy costs, is plotted versus the length of the distribution line. The cost associated with three levels of annual consumption

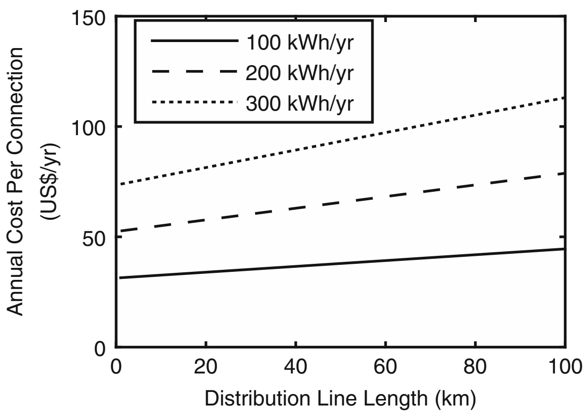

Fig. 3.9 Example annual cost per connection, including energy and infrastructure costs, by grid extension of a hypothetical community, assuming three different levels of consumption

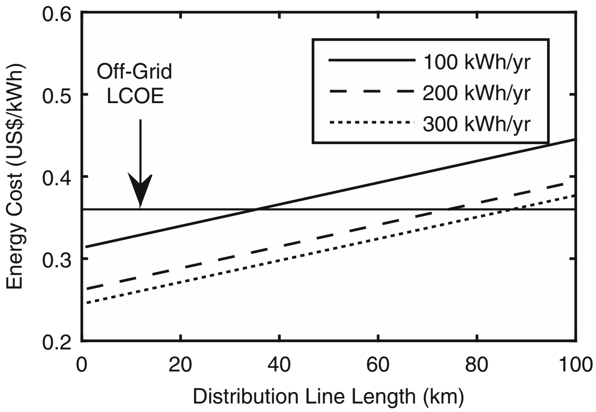

Fig. 3.10 Example total cost per kilowatthour of a hypothetical community, assuming three different levels of consumption. An example LCOE for an off-grid system is shown as the horizontal line

is shown. The grid extension costs increase with the length of the distribution line and annual energy consumption.

The slope of each line is different and increases with consumption, showing that higher-energy consumption requires more expensive, higher-capacity lines and transformers. The vertical axis intercepts are the annual costs for under-the-grid users. It includes the energy costs plus costs that are independent of the distribution line's length, such as metering and wiring.

Another family of curves of interest is the cost per unit energy, as shown in Fig. 3.10. This curve reflects that, although the cost of connecting a user with high consumption is greater than a user with low consumption, the cost per kilowatthour can be less. This curve is used to compare competing electrification approaches. Also shown is the LCOE for a hypothetical off-grid system. The intersection of the horizontal LCOE line with the grid extension cost curve gives an indication of the line length the off-grid system becomes a cost-effective solution. For example, if the consumption is 100 kWh/household/year, then the off-grid system becomes cost-effective if the required distribution line length exceeds 35 km. This is an approximation only as the off-grid solution might itself have localized infrastructure costs that are not included in the LCOE.

3.6 Rural Electrification Programs

Grid extension is often coordinated by the national utility and a Rural Electrification Authority (REA). REAs are government agencies that promote, coordinate, manage funds, train, build capacity, or implement rural electrification.

REAs in Sub-Saharan Africa became popular beginning in the late 1990s to mid-2000s. REAs were established during this period in Kenya (1997), Senegal (1998), Zambia (2003), Nigeria (2005), and Tanzania (2005), among others. In many countries, the REA develops a rural electrification master plan (REMPs). REMPs outline strategies for achieving specific electrification targets that align with broader development goals, for example, 51% electrification by the year 2030. REMPs estimate the cost of achieving the targets and identify technological, regulatory, and financial and economic barriers, risks, and opportunities. The REA identifies priority locations and user types, for example, schools and health facilities, for electrification.

Companies and organizations considering an off-grid electrification program should consult with the relevant REA so that the program is coordinated in the broader electrification efforts in that country. Installing mini-grids or deploying solar home systems and solar lanterns to a community can be wasteful if the grid is extended a short time later.

3.7 Other Considerations

The decision to extend the grid to serve additional communities is largely based on economic factors. However, there are other aspects that should be considered with this mode of electrification.

3.7.1 Prioritizing Electricity Access

With limited budgets, prioritizing which areas to electrify is especially important. Although each country has a different process, higher priority is usually given to communities that:

- have high potential for electricity consumption;
- are near (typically within 20 km) to the existing distribution network;
- are densely populated;
- have industrial, commercial, or tourism potential;
- have medical, educational, or other social institutions;
- have political or cultural significance.

An economic analysis and alignment with other development goals such as access to clean water further guide the prioritization.

3.7.2 Grid Extension to Remote Rural Areas

In the context of developing countries, grid extension to remote rural areas faces the following challenges in particular:

- inadequate supporting infrastructure such as roads makes construction and maintenance more difficult;
- distribution lines must span long distances and rugged terrain, increasing cost and losses;
- low load density and inability/unwillingness to pay for electricity make it difficult to recover infrastructure investment;
- the costs associated with meter reading is high, and so prepaid billing is favored.

The cost of extending the grid to remote communities can be so high that they are never recovered while being affordable to the user. The annual fixed cost in Example 3.9 was US$222.63 per connection. The consumption averaged 365 kWh per connection per year. For this connection to qualify as Tier 5 affordability, the cost cannot exceed 5% of the household income. The average annual household income must exceed US$4452.60. This income is beyond what many rural households can be reasonably expected to earn each year. For this access to satisfy the affordability attribute, the connection must be subsidized.

3.7.3 Cost-Reflective Pricing

In many developing countries, electricity is heavily subsidized by the government. This means that the rate that users pay per unit of energy is lower than it costs the utility to supply it, even in urban areas. The subsidy is a transfer of money from the government to the utility so that the utility is able to operate.

In many countries, subsidies are available to grid-connected users, but not to those served by small-scale off-grid systems. This discourages investment in off-grid solutions. Many mini-grid developers are forced to charge higher rates than offered by the grid in part because of the subsidies available for grid-connected electricity.

The reality in many developing countries is that the utilities or government loses money on many users, particularly those in rural areas. If the benefits of access to electricity are not properly accounted for, for example, the educational, health, and economic benefits associated with electrification, then the utility or government might be reluctant to increase electrification rates.

3.8 Summary

The de facto approach to increasing electricity access is to extend or enhance the existing grid. Connecting consumers in urban and peri-urban areas is more economical and expeditious than those in rural areas far from the existing grid. A grid extension project includes the design of the substation, medium-voltage distribution line, transformer, and user connections through low-voltage lines. The distribution line must be designed to supply the required power at an acceptable voltage while not exceeding the thermal limits of the line.

The economics of grid extension are largely driven by the length of the distribution line, which often exceeds US$20,000/km. The per connection cost is usually at least several hundred US dollars, although the user might pay a lower, subsidized amount. It is important to consider the lifetime cost of a grid extension project, not just the initial construction costs. The energy costs must also be considered. In general, off-grid systems are economically favorable to grid extension for communities far from the existing grid and whose consumption is low. Practical considerations in grid extension include determining which areas to prioritize for access and whether or not to subsidize the cost.

Problems

3.1 A three-phase distribution line whose line-to-line sending-end voltage is 22 kV supplies 2.25 MW at a power factor of 0.85. Compute the magnitude of the current through the a-phase conductor.

3.2 A distribution line has an impedance of $Z = 6.73 + j4.87\ \Omega$. The receiving-end line-to-line voltage magnitude is 30 kV. The load is 1.9 MVA at a power factor of 0.85 lagging. Compute the a-phase conductor current, the magnitude of the sending-end line-to-line voltage, and the voltage drop in percent.

3.3 Verify that 98.8 A is the maximum conductor current that does not exceed the voltage drop limit of 5% in Example 3.2. Compute the current that results in a 10% drop.

3.4 Determine the infrastructure cost c_{grid} and cost per connection of the five villages whose characteristics are shown in Table 3.4. Use the cost coefficients provided in Table 3.5.

3.5 For the five villages described in the previous problem, compute the fixed annual infrastructure cost per connection, assuming a 40-year lifespan, a discount rate of 3%, and an annual maintenance cost of 1%.

3.6 What is the smallest conductor from Table 3.1 that can be used in a three-phase distribution line to supply the village of Dandandu without exceeding a voltage drop of 7.5% or the conductor's ampacity? Assume the line-to-line receiving-end voltage is 33 kV. Assume the conductor spacing is 1 m.

Table 3.4 Village characteristics

	Ababju	Bersoloi	Changola	Dandandu	Ekong
No. of households	500	1,000	5,000	8,000	10,000
Distance to grid (km)	20	8	12	25	10
Distribution line rating (MVA)	1	1	2	3	6
Low-voltage line length (km)	7	8.5	40	60	165
No. of 50 kVA transformers	23	28	45	69	130

Table 3.5 Cost coefficients

Parameter	Value
Distribution line, β_{line} (US$/MVA)	2000
Low-voltage β_{LV} (US$/km)	10,500
Transformer β_{xfmr} (US$/kVA)	180
Substation β_{sub} (US$/MVA)	40,000
Substation α_{sub} (US$)	180,000
User β_{UPE} (US$/User)	120

3.7 The fixed annual grid extension cost for a community of 400 households is US$20,750. It is estimated that each household will consume 50 kWh of energy per year (primarily for lighting). The LCOE from the grid is US$0.15/kWh and losses are 11%. Compute the annual total cost per household per year $c_{\text{total,annual}}/N_{\text{user}}$.

3.8 Consider the community in the previous problem. As an alternative to grid extension, solar home systems (SHS) are considered. Each SHS meets the electricity demands of a single household and costs US$275. The system requires replacement every 5 years. Assume the cost of the SHS does not change over time. Which solution—grid extension or solar home systems—is more economical?

3.9 A diesel-powered mini-grid is proposed as an alternative to a grid extension project. The mini-grid will serve 100 households and requires 1 km of low-voltage line and UPE for each household. The LCOE is US$0.50/kWh. Each household will consume 300 kWh per year. The losses are 7%. Compute the annual total (infrastructure plus energy) cost per user using the coefficients in Table 3.5. Assume the discount rate is 4% and the lifespan is 25 years.

3.10 As an alternative to the mini-grid in the previous problem, grid extension is proposed. The LCOE from the grid is US$0.18/kWh. The losses are 12%. The annual infrastructure cost per user is modeled as

$$c_{\text{total,annual}} = 56 + 3.30 \times l$$

where l is the distance of the community to the grid in kilometers. How far from the grid must the community be for the mini-grid to be economically justifiable?

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