AFRICAN SCHOOL OF REGULATION

Technology, management and regulation of electric power systems, with a focus on Africa

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"Electric power systems are generally regarded to be the largest and most complex industrial systems ever built"

Today's developed societies are inconceivable without electric power. Indeed, in societies where basic human needs such as food, health care, decent housing and education are met, "electricity and running water" are usually the two primary conveniences immediately associated with quality of life. Electricity, with its versatility and controllability, instant availability and consumer-end cleanliness, has become an indispensable, multi-purpose form of energy. Its domestic use now extends far beyond the initial purpose, to which it owes its colloquial name ("light" or "lights"), and has become virtually irreplaceable in kitchens for refrigerators, microwave ovens, washing machines, cooking stoves or dishwashers and any number of other appliances, and in the rest of the house as well, for air conditioning, heating, radio, television, phones, computers and the like. Electric mobility dominates transport by railway in many countries and electric drives – in cars, buses, trucks, motorbikes and three-wheelers – are predicted to replace combustion engines. Electricity usage is also indispensable in the commercial and industrial domains: in addition to providing power for lighting and air conditioning, it drives motors with a host of applications such as lifts, cranes, mills, pumps, compressors or other machine tools. Industrial activity that uses no manner of electricity is simply unimaginable. The complete decarbonisation of the economy that is necessary to fight climate change will require the electrification of most economic activities that consume energy. However, still 760[2] million people do not have access at all to any form of electric power and at least 3 billion only have unreliable power that is unsuitable for many productive, commercial and even residential utilisation.

This document is intended to refresh basic concepts that many readers may already have and establish firm grounds on which to build further knowledge. Although the content of this technical note may well be familiar, it will give readers an overview of electricity systems while serving as an introduction to matters that may be decisive for a more comprehensive understanding of the more specific topics that will follow in the course.

This document is organized into six sections: the core content is found in sections three and four, which address the technology and management of electric power systems. The remaining sections revolve around these two, discussing the causes determining and the consequences arising from these issues. Specifically, section one describes the properties that distinguish electricity from other products, and section two places electric power systems in their historical context. Section three describes the components of a power system from generation to consumption, whereas section four reviews the operation and the decision-making process on different time scales, from long-term to real time. Section five deals with the importance of environmental impact, one of the issues that clearly conditions the future of the industry. The chapter concludes with a brief section on the future of electric power systems: foreseeable progress, the potential of technology, the challenges to be addressed and the radical change visible on the horizon. The intention is

[2] IEA, World Energy Outlook 2023, https://www.iea.org/reports/world-energy-outlook-2023

not, of course, to predict the future but simply to draw attention to issues that may induce significant change in electric power systems[3].

1. BACKGROUND

At first glance, electricity may appear to be a commodity like any other. Indeed, this perspective may be behind the wave of liberalisation and deregulation in the last decade of the last century and the first of this one that has transformed so many other sectors of the economy. And yet, electricity is defined by a number of characteristics that set it apart from other products and have made it more difficult to implement such changes in the electricity industry.

The chief characteristic of electricity as a product that has differentiated it from all others is that it is not liable, in practice, to being stored in large quantities, although this feature is undergoing a swift change nowadays. Electricity can be stored in batteries of different sizes, which are presently used in multiple applications, but price and performance have made this impractical for handling the amounts of energy usually handled at bulk power system level. This may change in the near future but, at present, electricity must be largely generated and transmitted as it is consumed, which means that electric systems are highly dynamic and complex, as well as immense. At any given time, these vast interconnected systems must strike a balance between generation and demand, and the disturbance caused by the failure of a single component may be transmitted across the entire system almost instantaneously. This sobering fact plays a decisive role in the structure, operation, and planning of electric power systems, as discussed below.

Another peculiarity of electricity has to do with its transmission: this is not a product that can be shipped in "packages" from origin to destination by the most suitable medium at any given time. Electric power is transmitted over grids in which the pathway cannot be chosen at will, but is determined by the laws of physics (in this case Kirchhoff's laws), whereby current distribution depends on impedance in the lines and other elements through which electricity flows. Except in very simple cases, all that can be said is that electric power flows into the system at one point and out of it at another, because ascribing the flow to any given path is simply not possible. Moreover, according to these laws of physics, the alternative routes that form the grid are highly interdependent, so that any variation in a transmission facility may cause the instantaneous reconfiguration of power flows; and that, in turn, may have a substantial effect on other facilities. All this renders the dynamic balance referred to in the preceding paragraph even more complex.

Indeed, for all its apparent grandiloquence, the introductory sentence to this chapter may be no exaggeration. The combination of the extreme convenience of use and countless applications of electricity on the one hand and its particularities on the other has engendered these immense and sophisticated industrial systems.

Their size has to do with their scope, as they are designed to carry electricity to practically any place inhabited by human beings from electric power stations located wherever a supply of primary energy, for instance in the form of potential or kinetic

[3] This text is based on Chapter 1 of Pérez-Arriaga et al. (2013).

energy in moving water or of chemical energy stored in any of several fuels, is most readily available. Carrying electric power from place of origin to place of consumption calls for transmission and distribution grids or networks that interconnect the entire system and enable it to work as an integrated whole.

Off-grid electricity supply using stand-alone systems and minigrids - originally powered with diesel generators and sometimes with biomass or mini-hydro plants, but now more often with solar panels combined with batteries and sometimes back-up thermal generation - is increasingly being used, mainly in rural areas of developing countries and almost exclusively to serve semi-isolated communities in areas that are difficult to access and/or far from the main electricity grid. Standalone systems are also often used as back-up generation for residential, commercial and industrial customers, and even entire communities where the supply from the main grid is unreliable (mainly in developing countries), or simply to meet their own energy needs for various reasons – economic, environmental or empowerment. In addition to distributed generation, other devices - batteries, advanced meters, thermostats, electric vehicles and all kinds of smart appliances, generally referred to as "distributed energy resources" or DERs - are increasingly being connected to the electricity grid at the customer level.

The sophistication of interconnected electric power systems is a result of the complexity of the problem of permanently maintaining the balance of supply and demand, with the characteristics discussed above. This dynamic equilibrium between generation and demand is depicted in the highly regular patterns followed by the characteristic magnitudes involved: the value and frequency of voltage and currents as well as the waveform of these signals. Such regularity is achieved with complicated control systems that, based on the countless measurements that constantly monitor system performance, adapt its response to ever-changing conditions.

A major share of these control tasks is performed by powerful computers in energy management centres running a host of software applications: some estimate demand at different grid buses several minutes, hours, days or months in advance; other models determine the generation needed to meet this demand; yet other programs compute the flow in system lines and transformers and the voltage at grid buses under a number of assumptions on operating conditions or components failure, and determine the most suitable action to take in each case. Others study the dynamic behaviour of the electric power system under various types of disturbance. Some models not only attempt to determine the most appropriate control measures to take when a problem arises, but also to anticipate their possible occurrence, modifying system operating conditions to reduce or eliminate its vulnerability to the most likely contingencies.

This, however, is not all: the economic aspect of the problem must also be borne in mind. The actors that make the system work may be private companies that logically attempt to maximise their earnings or public institutions that aim to minimise the cost of the service provided. In either case, the economic implications of the decisions made cannot be ignored, except, of course, where system security is at stake.

The system nearly always operates under normal conditions, leaving sufficient time to make decisions that are not only safe, but economically sound. Hence, when a foreseeable rise in demand takes place during the day, power should be drawn from the facilities with unused capacity that can generate power most efficiently. The objective is to meet daily

load curve needs with power generated at the lowest variable cost. This new dimension in the operation of electric power systems is present in all time scales: from the hourly dispatch of generating plants to the choice of which units should start up and stop and when, including decisions on the use of hydroelectric reserve capacity, maintenance programming and investment in new facilities.

Moreover, all these decisions are made in a context of uncertainty: about the future demand to be met, availabilities of plants and of resources such as water in the reservoirs, wind or sunlight, the prices of the various factors involved in the production process – the fuels in particular –, the international measures adopted against climate change and the actual legislation to implement them in the various countries.

2. EARLY HISTORY

The first electric light systems, installed around 1870, consisted of individual dynamos that fed the electrical system (arc lamps) in place in a single residence. Joseph Swan and Thomas Edison worked separately on the incandescent light bulb until 1880 and Edison spawned the idea of increasing the scale of the process by using a single generator to feed many more bulbs. The first town in the world to establish a public electricity supply was Godalming, UK, in September 1881: a waterwheel on the river Wey powered a Siemens alternator and a dynamo that fed 7 arc lights and 34 Swan incandescent lights. In 1882, Edison's first generator, driven by a steam turbine located on Pearl Street in lower Manhattan, successfully fed a 100-volt direct current (DC) to around four hundred 80-watt bulbs in office and residential buildings on Wall Street. Shortly thereafter, London's 60-kW Holborn Viaduct station was commissioned, which also generated 100-V direct current. This local generation and distribution scheme was quickly adopted, exclusively for lighting, in many urban and rural communities worldwide.

The first recorded use of electric power in Africa dates back to 1882 in South Africa, when the first streetlights were light up in Diamond City, Kimberley, and electric lights were used in the local mining industry. This introduction of electric power was closely tied to the rapid development of the mining sector, particularly for diamonds and gold, which played a significant role in the economic growth of the region. This event marked the beginning of the electrification process in Africa, though it would take many more decades for electricity to become widely accessible across the continent. In Egypt, the first use of electric power is often associated with the inauguration of electric street lighting in Cairo in 1893 as part of a broader modernization efforts during this period. Lagos, the then-capital of Nigeria, saw its first electricity supply in 1898. This was primarily used for street lighting, marking an important milestone in the country's move towards modernization.

The invention of the transformer in France in 1883-84 revealed, in a process not free of controversy, the advantages of alternating current (AC), which made it possible to conveniently raise the voltage to reduce line losses and voltage drops over long transmission distances. Alternating, single-phase electric current was first transmitted in 1884, at a voltage of 18 kV. On 24 August 1891, three-phase current was first transmitted from the hydroelectric power station at Lauffen (Germany) to the International Electro-Technical Exhibition in Frankfurt, 175 km away. Swiss engineer Charles Brown, who with his colleague and fellow countryman Walter Boveri founded the Brown-Boveri

Company that very year, designed the three-phase AC generator and the oil-immersed transformer used in the station. In 1990, the Institute of Electrical and Electronic Engineers, IEEE, agreed to establish 24 August 1891 as the date marking the beginning of the industrial use and transmission of alternating current.

The transmission capacity of alternating current lines grows fast with voltage, whereas the cost per unit of power transmitted swiftly declines. There was, then, an obvious motivation to surmount the technological barriers limiting the use of higher voltages. Voltages of up to 150 kV were in place by 1910 and the first 245-kV line was commissioned in 1922. The maximum voltage for alternating current has continued to climb ever since. Nevertheless, direct current has always been used as well, since it has advantages over alternating current in certain applications, such as electrical traction in the past and especially electricity transmission in overhead, underground or submarine lines, when the distances are too long for alternating current.

The alternating voltage frequency to be used in these systems was another of the basic design parameters that had to be determined. Higher frequencies can accommodate more compact generating and consumption units; this advantage is offset, however, by the steeper voltage drops in transmission and distribution lines resulting from their use. All of Europe, Africa, Asia, Australia, New Zealand and most of South America adopted a frequency of 50 Hz, whereas Japan, Taiwan, North America and some parts of northern South America opted for a frequency of 60 Hz. Low voltage consumers within most 50 Hz regions are supplied at 230 V, while in 60 Hz regions the voltage is generally 110 V. The International Electrotechnical Commission was created in 1906 to standardise electrical facilities everywhere as far as possible. It was, however, unable to standardise frequency, which continues to divide countries around the world into two separate groups.

The advantages of interconnecting small electric power systems soon became apparent. The reliability of each system was enhanced by the support received from the others in the event of emergencies. Reserve capacity could also be reduced, since each system would be able to draw from the total grid reserve capacity. With such interconnections, generating units able to meet demand most economically at any given time could be deployed. This affords particular advantage when peak demand time frames vary from one system to another and when the generation technology mix (hydroelectric and steam, for instance) likewise differs. In 1926, the British Parliament created the Central Electricity Board and commissioned it to build a high-voltage grid that would interconnect the 500 largest generation stations then in operation.

3. COMPONENTS OF A POWER SYSTEM

Electric power systems have developed along more or less the same lines in all countries, converging toward a very similar structure and configuration. This is hardly surprising, bearing in mind the very specific characteristics of the product sold. As mentioned earlier, electricity generation, transmission, distribution and retailing are inevitably conditioned by the fact that generation and demand must be in instantaneous and permanent balance. The relevance of technical factors in maintaining such large-scale systems in dynamic equilibrium cannot be overlooked. A disturbance anywhere in the system may endanger the overall dynamic balance, with adverse consequences for the supply of electricity

across vast areas, even whole regions of a country or an entire country. It is perhaps for this reason that the existence of sophisticated real-time control, supervision and monitoring systems, together with distributed local protection devices, is what chiefly differentiates the configuration and structure of electric power systems from other industrial activities in terms of technology. The functions typical of any industry, such as production, shipping, planning and organisation, are also highly specialised in the electricity industry.

Electric power systems, like any other industry, are made up of production centres, or generating plants; transmission (equivalent to transport or shipping in other industries), i.e., the high-voltage grid (network is also used, equally); distribution, in this case the low-voltage grid or network; and consumption (also termed demand or load), in addition to the associated protection and control systems. More formally, system configuration and structure are as depicted in Figure 1.

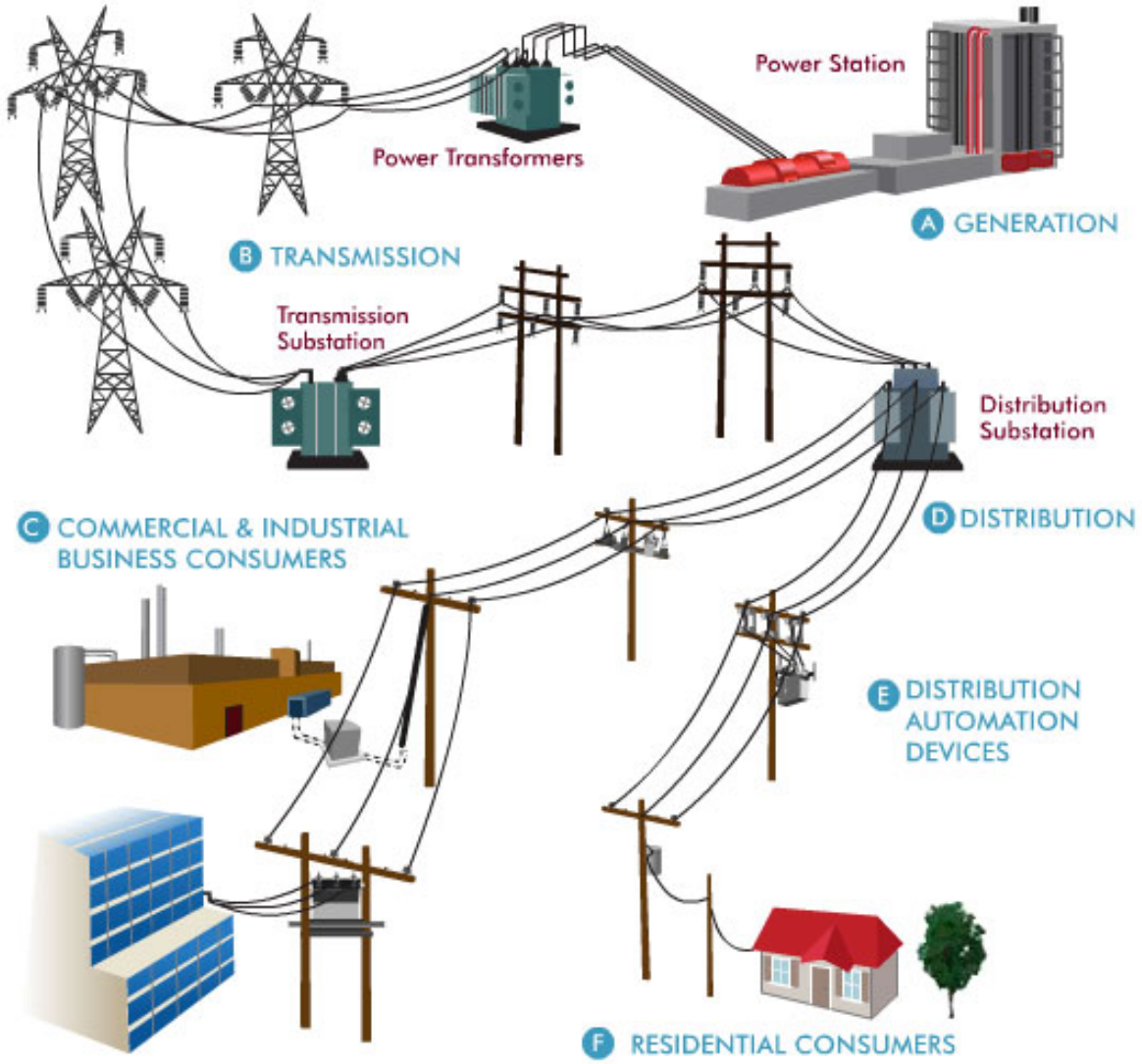


Figure 1. Traditional electric power system configuration and structure.

The significant presence of DERs – either actual or anticipated – necessitates a reconsideration of how these resources can most effectively provide electricity services. It implies that the electric power sector's customary "top-down" paradigm must be revisited, and that a fresh look at the design, operation, and regulation of distribution and

transmission networks is required, see Figure 2.[4] However, and despite the growing presence and relevance in power systems of distributed and off-grid energy resources, the present document has been largely structured following the traditional approach, which must be understood before venturing into the additional layer of complexity that is necessary to deal with DERs.

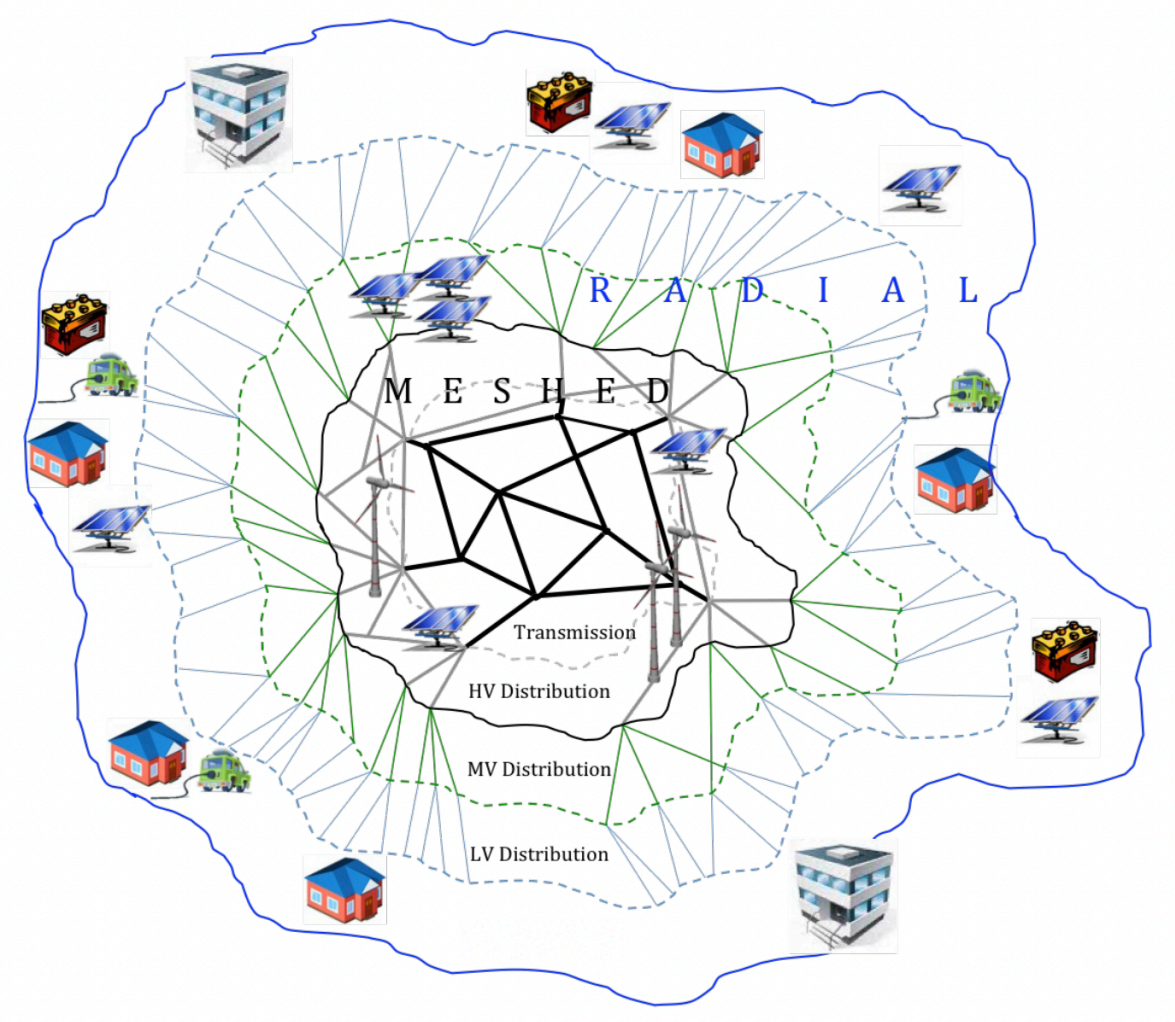


Figure 2. Beyond the "top down" paradigm.

Production centres connected to the main grid typically generate electricity at 6 to 20 kV and immediately transform this power into voltages of hundreds of kilovolts (132, 230, 400, 500 and 700 kV are relatively common values) to optimise long-distance transmission over electric lines to the areas where consumption is most intense.

Raising the voltage makes it possible to transmit large amounts of electric power (the entire output from a nuclear-powered generator, for instance) over long distances using reasonably inexpensive overhead lines technology with modest line losses. The transmission grid interconnects all the major production and consumption centres,

[4] The source of Figure 2 and an in-depth discussion of the expected role and regulatory principles to address the presence of DERs in the power system is Pérez-Arriaga et al. (2016) "The Utility of the Future", MIT Report, https://energy.mit.edu/publication/utility-future-report/

generally forming a very dense mesh to guarantee high reliability, with alternative pathways for the supply of electric power in the event of failure in a few of the lines.

These electric power transmission motorways are interconnected at communication nodes known as electric substations; the regional grids connect to these substations at a somewhat lower voltage (132, 66 or 45 kV in Spain, for instance) and in turn feed local distribution networks, which bring electric power to consumers at less hazardous voltages, adapted to consumer needs: 20, 15, 6.6, 3 or 1 kV and 380, 230 or 110 V.

Successive substations step the working voltage down in several phases and centralise the measuring and protection devices for the entire transmission grid.

The configuration of these distribution grids is usually radial, with tentacles stretching out to even the most remote consumption points. As the lines are split up at each step, the grids carry less and less power and consequently can operate at lower voltages.

Consumers connect to the voltage level best suited to their power needs, in accordance with the basic principle that the smaller the power capacity, the lower the voltage. This means that highly energy-intensive businesses (iron and steel plants and mills, aluminium plants, railways, and the like) connect directly to the high voltage grid; other major consumers, such as large factories, receive power at a somewhat lower voltage, while small consumers such as households, retailers and small factories, are connected to the low-voltage network.

Based on a roughly reciprocal principle, distributed generation resources with a very small output feed their electric power directly into the distribution network, instead of connecting to the high-voltage grid. Medium size wind or solar farms, from tens up to one hundred megawatts or more, connect to the medium or high voltage distribution network.

The items below focus on these chief components of electric power systems: demand, production, transmission, and distribution.

3.1. Demand

Demand growth

Global electricity demand has experienced high, sustained growth from the outset. The creation of standards for the electricity "product", in terms of voltage, frequency and current, paved the way for the enormous boom in electricity consumption. This in turn laid the grounds for further standardisation of electric fixtures and facilities, from light bulbs and motors to personal computers and phones, dramatically lowering manufacturing costs and enhancing product versatility, making it possible to use a given electrically-powered item virtually anywhere.

Electricity consumption is one of the clearest indicators of a country's industrial development, and its growth has traditionally closely tracked GDP growth, as there are few production processes or wealth-creating sectors that do not require electricity. Furthermore, electric power consumption has also been used as a measure of social development. Electricity consumption per capita and especially the degree of electrification in a country (i.e., the percentage of the population living in homes with

electricity) provide a clear indication of the standard of living. This is not surprising, since such basics as lighting, a supply of clean water, refrigerators and other household appliances depend on access to electricity.

The breakdown of electricity consumption by sector and the evolution of electricity final consumption by sector in Africa since 2000 are shown in Figure 3.

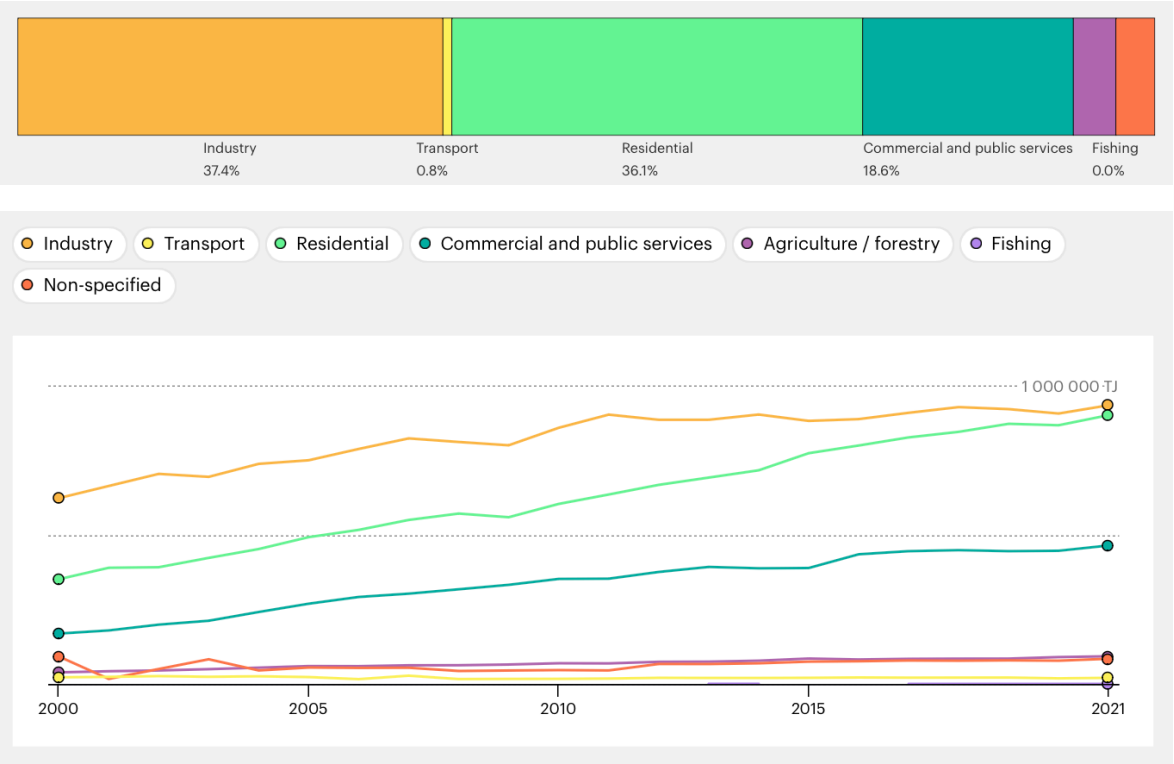


Figure 3. Source IEA. https://www.iea.org/regions/africa/electricity

Africa has achieved impressive progress in ensuring access to energy, with population coverage increasing from 42% to 56% in seven years. However, 600 million Africans still lack access to electricity, representing three-quarters of the world's unserved population. Most reside in rural areas of African countries such as the Democratic Republic of Congo (DRC), Madagascar, Ethiopia, Nigeria, Tanzania, and Uganda. Energy is also needed for clean cooking. Over 900 million Africans lack access to clean cooking, with the majority living in rural areas. Cooking with traditional polluting fuels harms the environment, depletes forests, and negatively impacts human health, leading to an estimated 3.2 million premature deaths each year due to indoor pollution. Unfortunately, the share of Africa's population with access to clean cooking technology is only 30%, a figure which has fallen since 2015, as clean cooking related programmes and investment have not kept pace with population growth.[5]

Table 1 presents key energy indicators that allow to establish interesting comparisons between the electricity demand per capita in Africa and other regions of the world. Also,

[5] Annual Development Effectiveness Review 2023 / Chapter 1: Light up and power Africa. http://www.afdb.org/sites/default/files/news_documents/ader_2023_-_chapter_1.pdf

between population and CO2 emissions, for instance between China, India and Africa, all of them with similar population.

	Population (million)	Total energy supply (EJ)	Electricity demand (kWh per capita)	Cars per thousand people	CO_2 emissions (Gt)	CO_2 emissions (t per capita)
United States	336	94	12 133	682	4.7	14
Latin America and the Caribbean	658	37	2 253	137	1.7	3
European Union	449	56	5 521	557	2.7	6
Africa	1 425	36	508	25	1.4	1
Middle East	265	36	4 190	175	2.1	8
Eurasia	238	42	5 051	193	2.4	10
China	1 420	160	5 612	201	12.1	9
India	1 417	42	926	31	2.6	2
Japan and Korea	177	29	8 703	490	1.7	9
Southeast Asia	679	30	1 592	63	1.7	3

Note: EJ = exajoules; kWh = kilowatt-hours; Gt = gigatonnes; t = tonnes.

Table 1. Key economic and energy indicators by region/country, 2022 (IEA WEO 2023).

Figure 4 shows the estimated global electricity demand, in the interval 2010-2050, and the generation mix by the three scenarios examined by the International Energy Agency in its World Energy Outlook 2023.[67] Global electricity demand is set to increase rapidly in all scenarios as a result of population and income growth and the electrification of increasing numbers of end-uses. By 2050, demand for electricity rises from its current level by over 80% in the STEPS, 120% in the APS and 150% in the NZE Scenario. The additional demand is met mainly by low emissions sources of electricity – renewables, nuclear power, fossil fuels equipped with carbon capture, hydrogen and ammonia – raising their share of electricity supply in each scenario. The share of unabated fossil fuels declines sharply, with their combined output falling by over one-third from 2022 to 2050 in the STEPS, three-quarters in the APS and nearly 100% in the NZE Scenario.

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[6] The Stated Policies Scenario (STEPS) is designed to provide a sense of the prevailing direction of energy system progression, based on a detailed review of the current policy landscape. The Announced Pledges Scenario (APS) assumes that governments will meet, in full and on time, the climate commitments they have made, including their Nationally Determined Contributions and longer-term net zero emissions targets. As with the STEPS, the APS is not designed to achieve a particular outcome. The Net Zero Emissions by 2050 (NZE) Scenario depicts a narrow but achievable pathway for the global energy sector to reach net zero energy-related CO2 emissions by 2050 by deploying a wide portfolio of clean energy technologies.

[7] Figures and text in this section have been copied or summarized from the IEA 2023 World Energy Outlook.

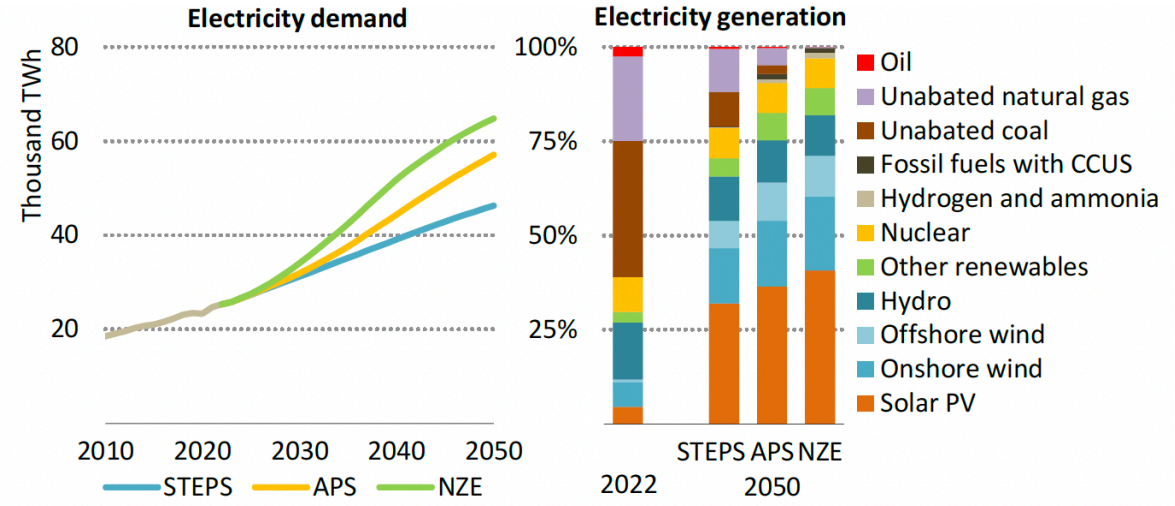


Figure 4. Estimated global electricity demand, in the interval 2010-2050, and the generation mix by the three scenarios in the IEA WEO 2023.

Global electricity demand growth to 2050 is driven by emerging market and developing economies, which together account for about three-quarters of the global total growth in the three scenarios. China's and India's electricity demand have been assumed to grow 2% and 5% per year, respectively, until 2050. Other emerging market and developing economies also see robust electricity demand growth stemming from increasing populations, economic development and rising incomes. Estimated electricity generation growth (an excellent proxy for demand) in Africa is shown in Figure 5. In advanced economies as a group, electricity demand growth is lower, ranging between 1.4% per year in the STEPS to 2.4% in the NZE Scenario.

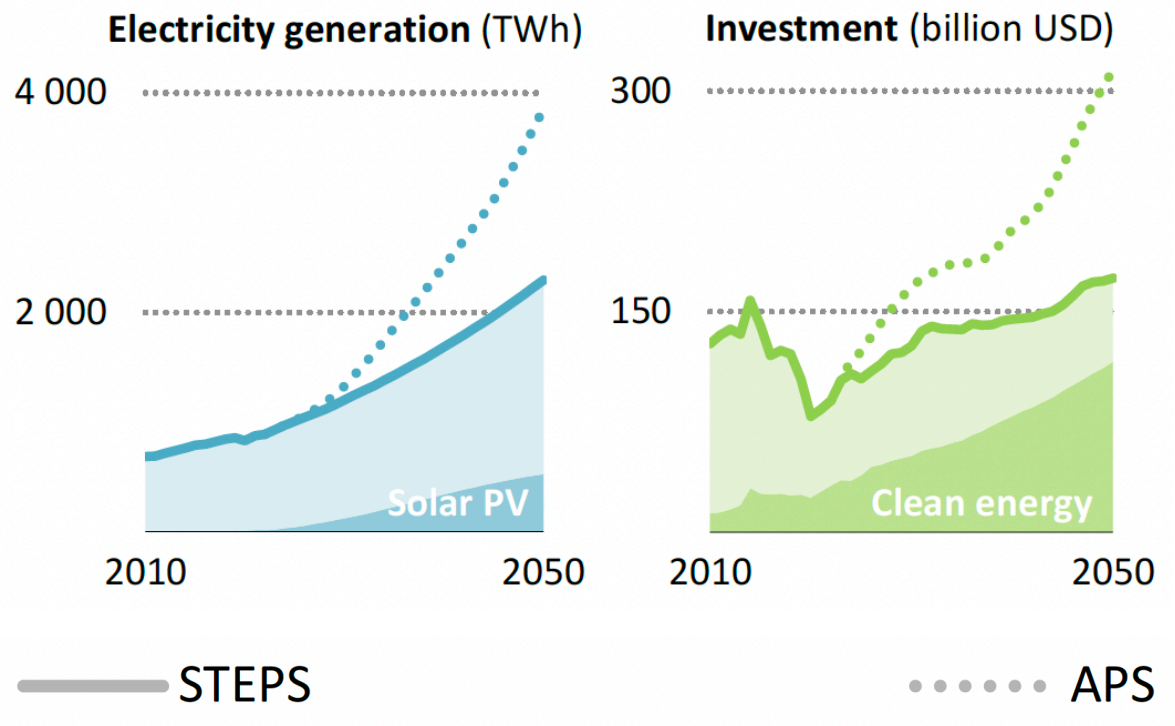


Figure 5. Key trends in Africa, 2010-2050.

Global electricity demand rises in all sectors and in all scenarios. The buildings sector remains the largest in terms of consumption through to 2050. The industry sector continues to be the second-largest user of electricity in the STEPS and APS but becomes the largest in the NZE Scenario. EVs account for at least 15% of total electricity demand growth to 2050 in all scenarios and become a key driver of electricity demand growth. The production of hydrogen via electrolysis remains limited in the STEPS but adds significantly to electricity demand growth in the APS and even more so in the NZE Scenario.

The growth in electricity consumption has steadied in developed countries but it is certainly not flat, and it is expected to grow because of the long-term trend of electrification of the economy: heating, cooling, cooking, mobility and industrial processes. Linked to climate change and to the general improvement in living standards, the generalised use of air conditioning in developed countries – and also increasingly in emerging and developing economies – has brought about a substantial change in seasonal consumption curves. With population growth and improved living standards in Africa, demand is set to double by 2040[8] despite substantial improvement in the efficiency of most equipment and processes using electric power, which reduces the input energy needed to attain a given result.

Energy efficiency and demand response.

There is a universal concern for the need to rationalise the consumption of electricity and all other forms of energy. Aware of the environmental impact of such consumption and the vast amount of natural resources that are literally going up in smoke, environmental organisations and policymakers rightly call for intergenerational solidarity so that coming generations can live in an ecologically acceptable planet whose energy resources have not been depleted.

The rationalisation of demand requires translating to consumers the consequences of their utilisation of electricity. A first approach – crude but effective – is the mandatory introduction of efficiency standards in all kinds of electric appliances, from lighting and other domestic appliances used for heating, cooling, cooking, various tools and many other uses, to the motors used in industrial applications.

Regulatory authorities should establish efficiency targets and associated penalties and credits in the activities performed by utilities, for instance in the transmission and distribution of electricity. Electricity losses in African countries currently stand at 17.1%, up from 15% in 2015[9], which are too high compared to the world average of about 8%[10], indicating the need to strengthen the networks and to improve their maintenance.

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[8] IRENA, The Renewable Energy Transition in Africa, https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/March/Renewable_Energy_Transition_Africa_2021.pdf

[9] Annual Development Effectiveness Review 2023 / Chapter 1: Light up and power Africa. http://www.afdb.org/sites/default/files/news_documents/ader_2023_-_chapter_1.pdf

[10] https://data.worldbank.org/indicator/EG.ELC.LOSS.ZS

A more sophisticated but necessary approach consists of translating to consumers the consequences of their utilisation of electricity by means of correct economic signals reflecting the actual costs incurred by electricity consumption at any given time. Pricing should be designed to make consumers aware of the real economic and environmental cost of meeting their power needs, given their consumption patterns in terms of hourly profile and total load. In the medium term, this should stimulate domestic, commercial and industrial users to monitor and actively control electric consumption, in much the same way that discriminatory hourly telephone rates encourage customers to make non-urgent long-distance calls at off-peak times. Similarly, customers will voluntarily reduce electricity consumption by foregoing the most superfluous applications at times when higher prices signal that expensive resources are being deployed or that the margin between the demand and supply of electric power is narrow.

The ability of demand to respond to pricing is normally measured by a parameter known as price elasticity of demand. This is defined as the percentage variation in the consumption of electricity (or any other product) in response to a unit variation in its price. Generally speaking, electricity demand is scantly elastic in the short term; in other words, the reaction to changes in price is small, although this assertion is more accurate for some types of consumers than others. Such limited elasticity is arguably due to the mentality prevailing until very recently in the electricity industry: continuity of supply was regarded to be a nearly sacred duty, to be fulfilled at any price. Consumers, who were identified as *subscribers* rather than *customers*, were merely passive recipients of the service provided.

Advances in communications technology, in conjunction with the liberalisation of the electric and energy industries in much of the world and the availability of distributed energy resources (DERs, more on them later) – in particular small scale generation with rooftop solar panels and batteries and diesel or gas-fired generators – is radically transforming the role of consumers to a more active one of *prosumers*, although a change in mentality does not happen quickly. Nonetheless, numerous examples worldwide increasingly show the coming of age and intensification of the role played by responsive demand, together with local generation and storage, in the electricity industry. Elasticity will grow, particularly in the short term, and demand patterns – complemented by local generation and storage – will adapt better to system conditions, although this will not necessarily mean a total demand reduction.

Demand profiles

From a technical standpoint, consumption comprises a variety of items. The two most important are power and energy. Power, measured in watts (W), is the energy (Wh) required per unit of time. Power, therefore, is the instantaneous energy consumed; it is also referred to as demand or load. Since electric energy is not easily stored, electric facilities must be designed to withstand the maximum instantaneous energy consumed, in other words, the maximum power load on the system throughout the consumption cycle. Therefore, not only the total electric capacity needed, but the demand profile over time is especially important in determining consumption. Such profiles, known as load curves, represent power consumed as a function of time. It may be readily deduced that a given value of energy consumed may have a number of related load profiles. Some may be flat, indicating very constant electricity consumption over time, while others may have one or

several very steep slopes, denoting highly variable demand. An aluminium plant working around the clock 365 days a year and a factory operating at full capacity only during the daytime on weekdays would exemplify these two types of profiles.

Load profiles are usually repetitive over time. For example, the weekday demand profile is normally very uniform, as is the weekly load profile during a certain season. Therefore, depending on the time scale considered, the load profile to be used may be daily, weekly, monthly, seasonal, yearly or even multi-yearly. Load profiles also have economic significance, as will be seen in the discussion below: for any given demand level, a flat load profile can be accommodated less expensively to than a spiked curve. For this reason, load curves are one of the most important parameters considered in the methods used to set tariffs.

The sum of all the individual consumption curves for an electric power system yields the total daily, weekly, monthly, seasonal, yearly and multi-yearly load curves, each with a characteristic and highly significant power profile.

The figures below, taken from the Republic of South Africa (RSA) public utility Eskom, show the national electricity demand profiles. Figure 6 illustrates the system hourly demand compared against available capacity, to indicate the amount of surplus/shortfall there was. Notice how demand fluctuates within the different hours of the day. Figure 7 shows the forecasted demand for both residual and RSA contracted demand (the hourly average demand that needs to be supplied by all resources that Eskom has contracts with).

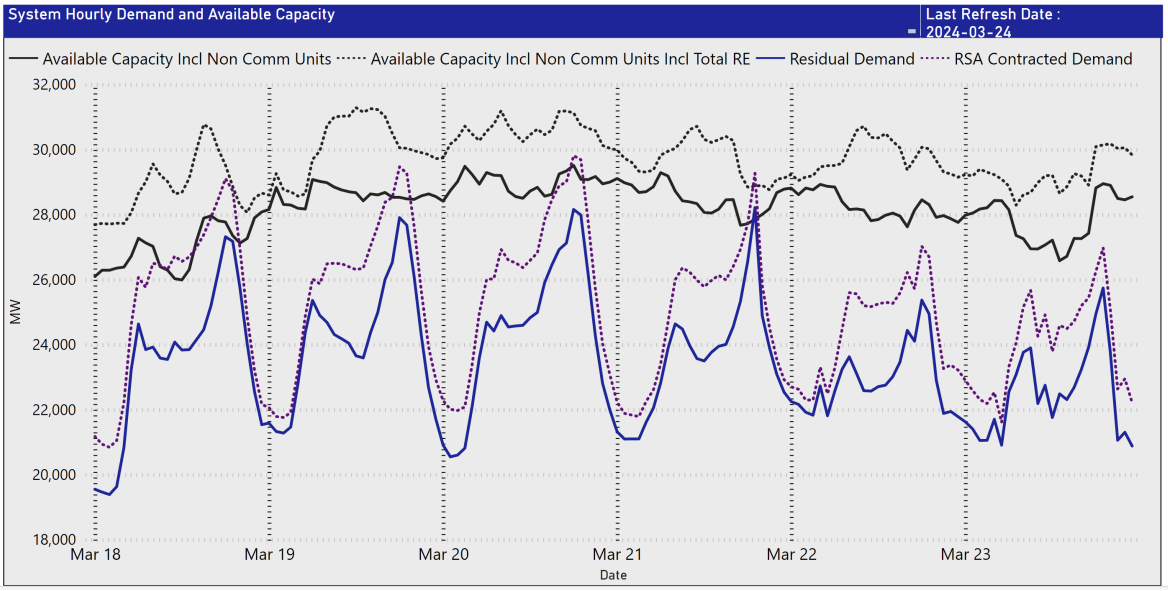


Figure 6. System Hourly Demand and Available Capacity.

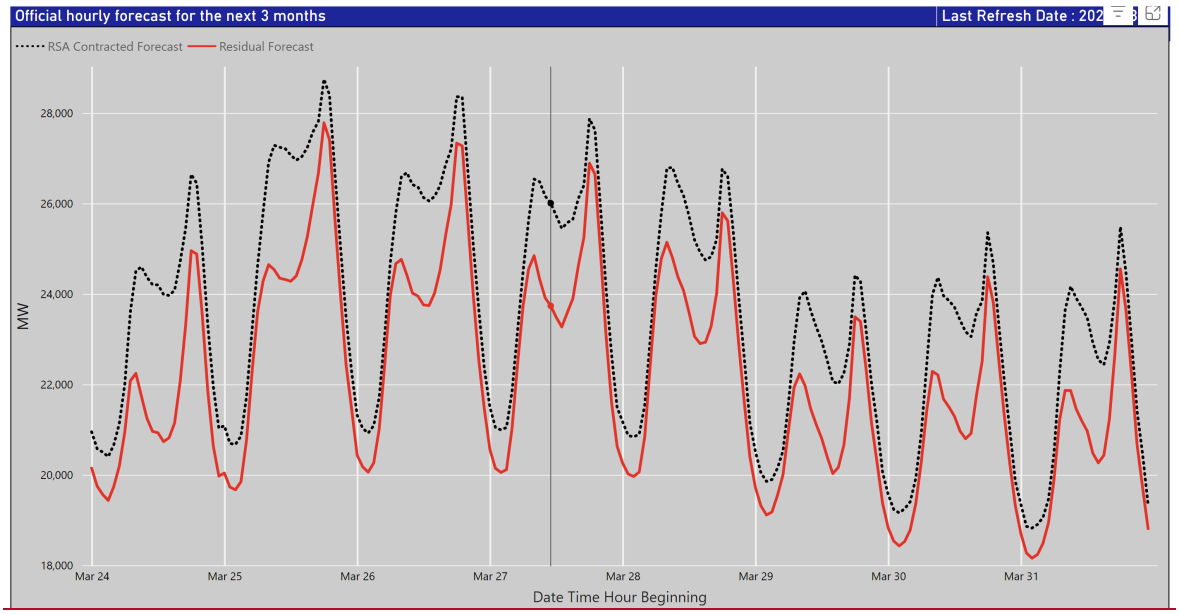


Figure 7. Hourly Demand Forecast.

To compare, the figures below, taken from the website of the Spanish Transmission System Operator (Red Eléctrica de España) show the demand profiles for the Spanish system. Figure 8 illustrates how the daily pattern changes with the season (winter vs. summer). Figure 9 shows how demand in the working days is significantly larger than in the weekends (Saturday larger than Sunday). Finally, Figure 10 illustrates how demand changes throughout the year, increasing in winter and summer due to the heating and air conditioning consumption.

Additionally, in order to illustrate how demand patterns strongly depend on the particularities of each electric power system, Figure 11 shows the chronological hourly load for the ERCOT power system. It can be observed how not only the annual pattern presents a significantly different shape, but also the daily ones both in winter and summer.

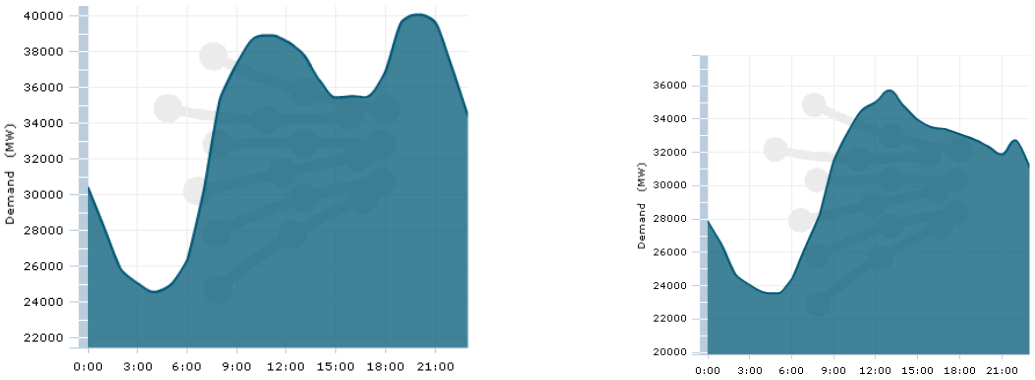


Figure 8. Electricity demand daily pattern in the Spanish system (winter: January 19th, 2011, left; and summer: July 20th, 2011, right)

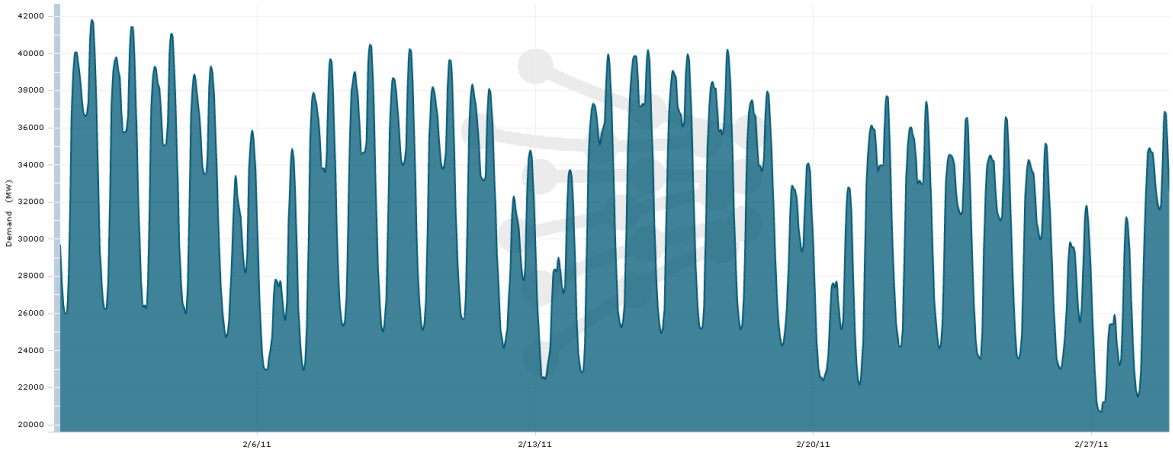


Figure 9. Electricity demand monthly pattern in the Spanish system (February 2011)

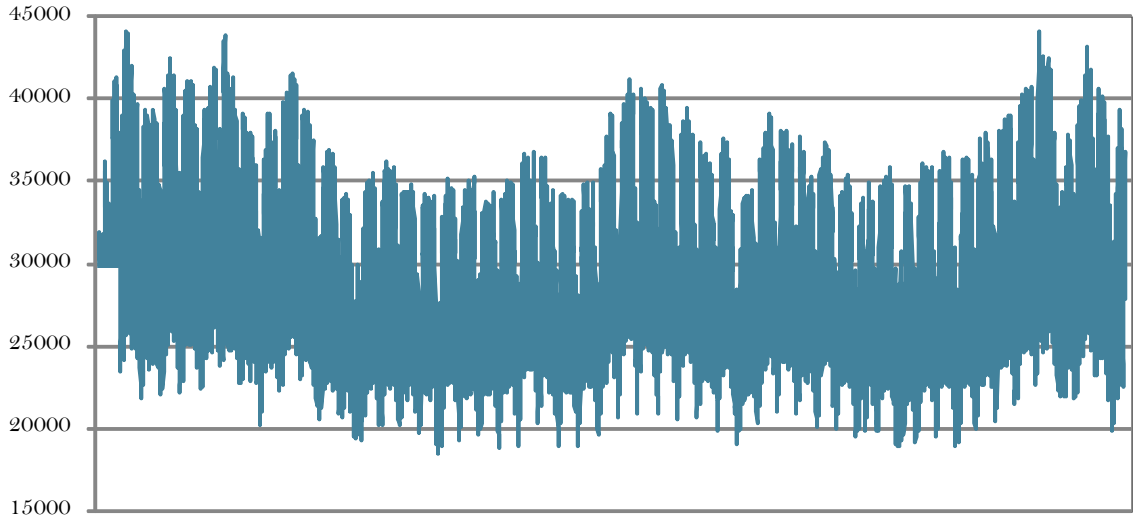


Figure 10. Electricity demand yearly pattern in the Spanish system (2010)

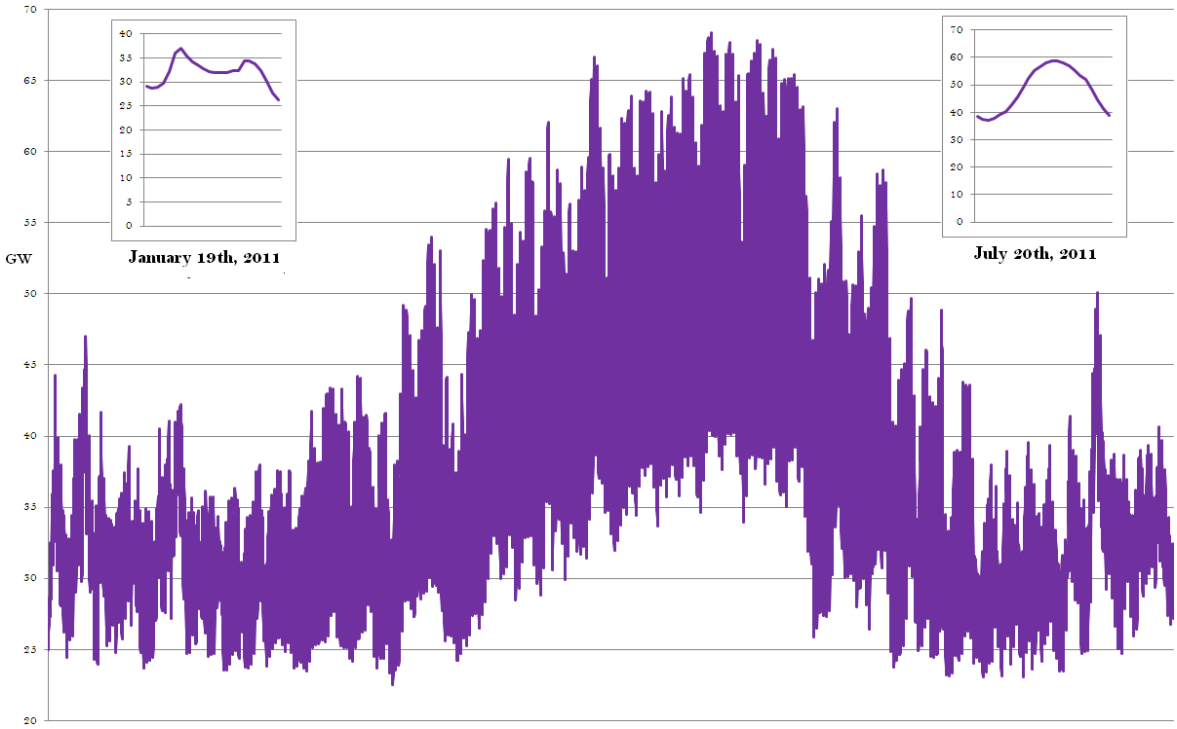


Figure 11. Electricity demand yearly and daily pattern in ERCOT (2011)

Demand forecasting is an essential problem to solve in anticipating the conditions under which the system will be operating in the short, medium and long term. The normal procedure is to base the prediction on historical data adjusted to take account of factors affecting the expected load. The most important of these factors include temperature, since many electrical devices are used for heating or cooling; number and dates of working days, to account for the difference in consumption on business days and holidays; and economic growth, in view of the above-mentioned close relationship between economic activity and electricity consumption. Therefore, consumption at any given time can be predicted reasonably well from time series data corrected for foreseeable variations in growth, working days and temperature, taking account as well of special events that may have a substantial effect on demand. Conversely, electricity consumption is a reliable and early indicator of economic crises and recoveries, as shown for instance in those countries affected by the world economic crisis that started in 2008.

Aggregate electricity consumption can also be represented as a monotonic load curve called the load duration curve, which is particularly useful in certain applications and studies. Such curves represent the length of time that demand exceeds a given load. The line in Figure 12 is the approximate monotonic load curve for the Spanish system in 2010: the abscissa values represent time in hours and the ordinate values demand in megawatts. Therefore, each point on the curve indicates the total hours during the year that demand exceeded a given value.

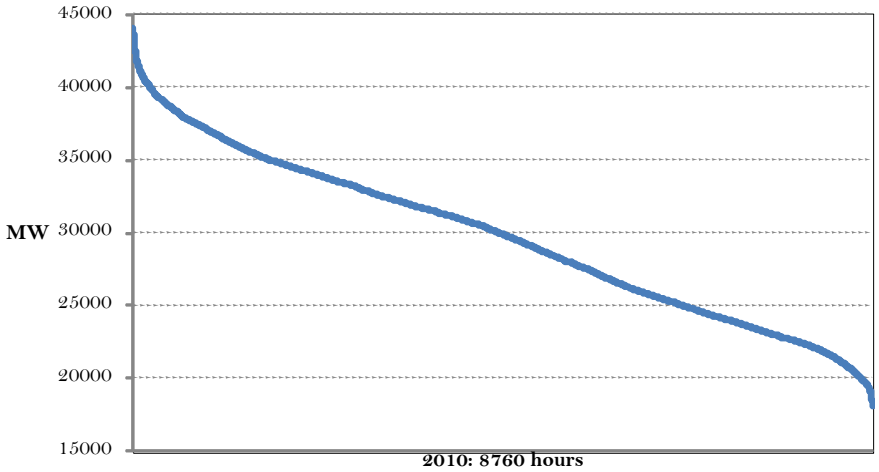


Figure 12. Load duration curve for the Spanish system in 2010

The load duration curve can be plotted directly from the chronological load curve by ranking demand in descending order, and therefore losing any chronological information. The integral of the load duration curve equals the energy consumed in the time frame considered. Note, however, that whereas a given load profile can have only one load duration curve, the opposite is not true.

Although the chronological information contained in load curves is lost in monotonic curves, the latter are widely used for their simplicity. Probabilistic monotonic curves are commonly applied in prospective studies, which are based on demand forecasts subject to some degree of uncertainty; in this case, the x-axis values represent the likelihood that demand will exceed a given value. As in the case of chronological demand profiles, monotonic load curves can be plotted for daily, weekly, monthly, seasonal, yearly or multi-yearly consumption.

In addition to the power/energy properties discussed at length in the foregoing paragraphs, consumption is characterised by other technical factors. Account must be taken, for instance, of the fact that while real power and energy are consumed in the system, reactive power is also either generated or consumed (usually the latter, since inductive motors, which consume reactive power, generally predominate). This gives rise to a power factor of less than one, which penalises consumption when this feature is included in the tariff, for it entails the circulation of non-productive current and with it ohmic losses and line capacity saturation. Moreover, consumption may depend on supply conditions such as voltage and frequency, may be static or dynamic and may vary with connection time due to heating or other effects. All of this must be taken into consideration in load modelling.

Quality of service

Electric power consumption may be very sensitive to the technical properties of the electricity supply. Many devices malfunction or simply do not operate at all unless the voltage wave is perfectly sinusoidal and its frequency and magnitude are constant and stable over time.

The performance of electrical devices depends on the quality of the current that powers them. Problems may also arise in almost any type of electrical device when the supply voltage is too low or too high (overvoltage). Computer, motor and household appliance

performance may suffer, or these devices may even fail altogether if the supply voltage swings up or down.

Most electrically-powered equipment, particularly expensive equipment or any regarded to be vital for the proper and safe operation of all kinds of processes, is equipped with fuses, circuit–breakers, switches or protection relays to prevent damage caused by voltage fluctuations outside an acceptable range. The motors that drive the cooling pumps in nuclear power plants, for instance, are fitted with under- and over-voltage protection that may even trip plant shutdown systems, given the vital role of these motors in safe plant operation.

Lastly, outages, whether short or long, are clearly detrimental to service quality. Who hasn't lost unsaved information representing hours of work on a PC because of an untimely power outage? But power failures can cause even greater harm in industries such as foundries or in chemical or mechanical processes whose interruption may entail huge losses.

In developed countries, where the universal supply of electricity is guaranteed, attention increasingly focuses on quality, as in any other commercial product. Consumption and consumers have become more demanding in this regard, and electricity industry regulation authorities assiduously include quality standards in laws and regulations. Designing the proper signals to combine efficiency with high-quality service is one of the major challenges facing the new regulatory system.

The basic factors that define electricity service quality are set out briefly below:

- Supply outages: supply interruptions may have serious consequences for consumers. The duration of such interruptions may be very short, in which case they are called micro-outages, often caused by the re-connection of switches after a short-circuit, or long. If they last more than a few minutes, they are known as sustained interruptions. Normally, the harm caused increases non-linearly with the duration of the interruption.
- Voltage drops: momentary dips in supply voltage caused by system short-circuits or failures, lasting only until the fault is cleared, or due to the start-up of nearby motors with high input demand when first switched on, occasioning voltage drops in the supply network. Some devices are especially sensitive to these drops, particularly motors whose electromagnetic torque varies with the square of the supply voltage.
- Voltage wave harmonics: deviations from the fundamental frequency of the voltage sine wave due to the saturation of ferromagnetic materials (in system transformers or generators, for instance) or to the loads themselves; these deviations may also have adverse effects on consumer appliances.
- Flicker: low-frequency fluctuations in voltage amplitude normally due to certain types of loads. Arc furnaces and electronic devices with thyristors usually cause flicker, which is detrimental to the proper operation of devices connected to the grid. The solution to this problem is complex, since it depends not on the supplier but on system loads.
- Overvoltage: voltage increases caused by short-circuits, faults, lightning or any other event, potentially resulting in severe damage to consumer appliances.

Collection of reliability data is poor in many African countries, but the available information shows that the key reliability indicators of frequency and duration of interruptions are high by international standards, with mixed performance across the sample of countries that have available information.[11] The latest World Bank Enterprise Surveys data suggests that customers across sub-Saharan Africa experienced an average of nine outages per month, each lasting an average of 5.7 hours.[12]

Overall, fewer than half of Africans enjoy a dependable supply of electricity from a national grid, with rural residents and poor people at a huge disadvantage. Instead, almost a quarter of Africans rely – either totally or as a backup – on other sources of electricity, mainly solar panels and generators.[13]

Lastly, it should be added that electric power consumption may vary widely with temperature or other circumstances. What must be borne in mind is, as mentioned earlier, that this demand must be met instantaneously; therefore, the electric power supply system, including power stations and transmission and distribution grids must be designed to detect and respond immediately to such variations. The system must be equipped with sophisticated measurement, control and monitoring equipment and must have reserve generating capacity able to come on stream at all times. Yet most users flipping switches in their homes or workplaces to turn on the lights or start up an appliance or tool are completely unaware of the host of systems, services and processes needed to provide that service.

3.2. Generation

The electricity required to meet these consumption needs is generated at production centres commonly called power plants or stations, where a source of primary energy is converted into electric power with clearly defined characteristics. Specifically, these facilities generate a three-phase, sinusoidal voltage system, with a strictly standardised and controlled wave frequency and amplitude. There are many generation technologies, usually associated with the fuel used. Conventional power stations are divided into hydroelectric, steam turbines –either fossil fuelled or nuclear plants– and combustion turbines, as described below.

The primary source of energy used in hydroelectric stations is water, which is expressed, energetically speaking, in terms of flow rate and height, or "head". Hydroelectric energy is converted by a hydraulic turbine into mechanical energy, characterised by the torque and speed of the shaft coupled to the electric generator. In other words, hydraulic energy is converted into electrical energy in the generator, producing voltage and current at the

[11] ESMAP-World Bank Group (2023), "Utility Performance and Behaviour in Africa Today (UPBEAT)". Update briefing. https://documents1.worldbank.org/curated/en/099092923144024459/pdf/P176468083bba20340a3520c1ffc74398ad.pdf

[12] World Bank Enterprise Surveys. https://www.enterprisesurveys.org/en/enterprisesurveys

[13] Afrobarometer. 2022. Still lacking reliable electricity from the grid, many Africans turn to other sources.

machine terminals. Because of the source of primary energy used, hydroelectric stations produce less atmospheric pollution than other conventional generation technologies. Another advantage of stations of this type, in addition to the cost of the fuel and lack of pollution, is their flexibility for connection, disconnection and output modification, making them highly suitable regulating stations for adjusting production to demand needs. Nonetheless, they are costly to build, and ensuring a steady supply of water normally involves flooding vast areas. Lastly, their operation is contingent upon a highly random factor typically: rainfall in the area where they are sited.

The many types of hydroelectric stations can be grouped under three main categories, which are distinguished by system operation.

- Conventional hydroelectric stations are the most common type. Their characteristics are as described in the preceding paragraph.
- Run-of-the-river plants have no storage capacity and consequently have to use water resources as they become available; for this reason, they cannot be used as regulating stations.
- Pumping power stations have a raised reservoir to which they can pump water when electric power is cheaper, and then dump it to a turbine when it is more cost-effective to do so. They can be regarded as an efficient means of storing energy, but not electricity per se.

Fossil fuelled steam thermal power stations**,** in which the primary energy is provided by coal, fuel oil or gas, are respectively termed coal-fired, oil-fired or gas-fired plants. The operating principle behind these stations is basically as follows:

- the fuel is burned in a boiler to produce high-pressure steam;
- high-pressure steam is converted into mechanical energy in the steam turbine;
- mechanical energy, as in hydroelectric plants, is converted into electric power by the generator.

The thermal efficiency of fossil-fuelled steam power stations, which convert chemical energy to thermal to mechanical to electrical energy, depends primarily on the calorific value of the fuel used. In any event, the highest efficiency reached is never over 45 %. Due to the heat inertia of the boiler, up to about seven hours depending on the type of plant, these stations cannot be readily connected and disconnected or made to follow steep ramps in their output, so they are less flexible in this respect than hydroelectric plants. In light of this circumstance, start/stop studies are conducted on steam power plants to establish operating orders, and the plants are sometimes placed in standby operation, without generating any power whatsoever. Although fuel may be subject to variations in price, in most countries a constant supply is assumed to be routinely available. Therefore, such stations can be used for load following or regulation, subject to their connection inertia and the flexibility in modifying their output.

Two basic types of conventional thermal plant technologies use gas as a fuel. One type is combustion gas turbine plants where, as in jet engines, gas combustion in high pressure air feeds a turbine that produces mechanical energy, in turn absorbed by an AC generator. The other, combined cycle or CCGT (combined cycle gas turbine) plants are

today's technology of choice and merit further comment. The operation of these stations, as may be inferred from their name, involves two types of cycles. In the primary cycle, a compressor attached to the shaft of a combustion gas turbine absorbs air at atmospheric pressure, compresses it and guides it to a combustion chamber where the gas that triggers combustion is likewise injected. The resulting gas expands through the turbine blades to produce mechanical energy. The exhaust gas expelled from the combustion gas turbine, which is still at a high temperature, is used to heat a water steam circuit so that the residual heat of the exhaust gas is exploited to run a classic steam cycle, as described above. Finally, electricity is produced by one or two AC generators, connected to a single common shaft or two separate shafts, one for each cycle. Thanks to the latest advances in ceramics –the materials used to provide thermal protection for the blades–, higher temperatures can be reached. Re-using very hot exhaust gases, in turn, results in substantially higher performance in these cycles than in open gas or conventional steam turbine cycles, with thermal efficiency values of up to 60 % in some facilities. This improved performance, together with a considerable reduction in polluting emissions, a high degree of modularity and reasonable investment costs, makes CCGT one of the most competitive generation technologies available.

Nuclear power plants, also known as atomic power plants, essentially consist of a nuclear reactor that produces vast amounts of heat through the atomic fission of uranium. This heat is transferred to a fluid (carbon dioxide, liquid sodium or water) and carried to a heat exchanger, where it is transferred to a water steam circuit. As in steam stations, the rest of the process involves transforming the steam produced into mechanical energy in a steam turbine and then into electric power with an AC generator. There are several drawbacks to the use of nuclear power plants, which make them socially controversial: the magnitude of the catastrophe in the event of an accident, no matter how low the risk, and the problem of eliminating radioactive waste. Another risk is related to nuclear proliferation, i.e., redirection of the technology toward nuclear weapon production or terrorist activities. Finally, these plants also entail a financial disadvantage: electric companies may have to become deeply indebted to defray the very large construction costs involved as well as the long construction time. In light of these difficulties, some countries have imposed a moratorium on the construction of new nuclear power plants. New smaller and modular nuclear power plants have been proposed and some prototypes are being built. From a system operation standpoint, nuclear power stations are base-load plants, rarely used for regulation because of their comparatively low variable production cost and their operational inflexibility, although this depends much on the plant design and may not represent a limitation. In liberalized electricity markets the typically high margin of electricity prices over nuclear plants variable costs induces companies to run these plants continuously at full capacity. This has changed with the strong presence in many power systems of highly variable generation with zero variable production cost, such as solar or wind. Inflexible plants and intermittent low-cost generators do not mix well in the absence of large and economically viable storage capacity.

In present electric power grids, most production currently takes place in so-called conventional stations, i.e., the sort described earlier. The share of other types of power stations in the generation mix has been gradually growing in some areas and countries, however, and has already reached very important penetration levels in some power systems. The main advantages of these technologies – wind, solar, biomass, geothermal

or wave power– are their limited environmental impact and the use of renewable sources of energy.

Wind farms may be fitted with synchronous AC generators, like the ones used in other types of power stations, or asynchronous machines, which accommodate small variations in speed when the torque fluctuates, to reduce equipment wear. In wind plants with asynchronous generators, capacitors are needed to generate the reactive power consumed by the induction machinery. These stations may be connected to the grid directly or indirectly, i.e., through a rectifier, inverter and filter. With the generation of direct current, plants can work at variable speeds. This comes at a cost, however, in addition to line loss and reliability issues, although the reactive power generated can be controlled by power electronics. Further development of this technology is expected with the implementation of off-shore wind generation.

Photovoltaic cells convert solar energy directly to DC current for storage in batteries or to be converted to AC current and injected to the grid. Electricity production with photovoltaic cells is basically indispensable in remote areas with difficult access to other sources of primary energy. The cost of electricity produced with photovoltaic (PV) cells has dropped dramatically during the last two decades and it is already the cheapest source of power at utility scale in many parts of Africa (IEA, 2022 Africa Energy Outlook). The cost of PV electricity is highly dependent on economies of scale, as it is now dominated by the balance of system, i.e. all the components of a photovoltaic system other than the photovoltaic panels, such as wiring, switches, inverters and the mounting system.

Conversely, in concentrated solar steam power stations solar radiation is used to heat a fluid and generate electricity thermodynamically. A variety of alternative solar thermal technologies are in place.

- Parabolic trough stations use parabolic reflectors to focus solar radiation on pipes and heat the receiver fluid they carry. This receiver then releases the heat to a steam turbine cycle, in stations using solar energy alone, or in a variety of cycles, in hybrid configurations.
- Central receiver or concentrated solar power tower stations have a field of heliostats (sun-tracking mirrors) that focus radiation on a receiver located on the top of a tower where the heat is stored, using a receiver fluid (liquid sodium or molten salts, for example), for subsequent use in any kind of power cycle. The main advantage is that higher temperatures can be reached than with parabolic troughs.
- The solar dish configuration is similar to the central receiver design but on a smaller scale, in which each module has its own "dishes" or parabolic disks and its own receiver. These plants, whose chief advantage is their modularity, generally use Stirling or gas turbine cycles.

Biomass generation, which involves obtaining energy from biological sources, such as energy crops (also called biomass feedstock), livestock waste or forestry residue, uses resources available in nearly any habitat and it is gaining popularity in rural areas of developing countries. This technology adopts one of two basic approaches.

- A direct combustion in specific furnaces to produce steam subsequently used in a turbine cycle, as in conventional steam power stations. This approach is often used in a CHP configuration (see next paragraph).
- An indirect process including a conversion that could be thermal or biological, transforming the organic matter into a combustible gas or liquid, generally used to feed an internal combustion engine or gas turbine coupled to an electric generator.

Finally, CHP (combined heat and power) or co-generation technology is based on the fact that many industrial plants have process heating requirements. The basic principle is to make industrial use of the surplus heat produced by some type of steam generation system instead of allowing it to simply dissipate as the return fluid cools.

The generation mix

The existence of a wide variety of technologies operating jointly in most countries can be justified in a number of ways.

Firstly, there is a purely economic justification resulting from the shape of the load curve. The range of fixed investment costs involved in building a power station and the operating costs of generating electricity vary widely from one technology to another. Nuclear power plants, for instance, call for very high investment, but have comparatively low operating costs, due to the low price of the fuel, in this case uranium, per unit of energy output. This factor makes nuclear power an attractive technology, from the standpoint discussed here, for the segment of the demand curve that reflects needs for 8760 hours in the year.

The other extreme is gas turbine technology, which has the highest operating but lowest investment costs, as well as a high level of operational flexibility, making it a very appealing type of generation to cover demand peaks, i.e., a relatively small number of hours per year, and to provide operating reserves to cope with imbalances of supply and demand in real time.

Conventional fossil-fired steam stations fall in between these two extremes. Obviously, the assumptions on which economic analyses are based and which justify the co-existence of different technologies always involve some degree of uncertainty in connection with factors such as the shape of the future demand curve, fuel costs, the specific operation of each generating station, capital costs, regulatory decisions and market prices (as appropriate).

Not only economic but also political and environmental considerations weigh heavily in the reasons for deploying a technology mix in electricity generation. Ensuring a supply of fuel as independent as possible from political and economic crises, be they international, such as more stringent decarbonisation objectives and natural gas price crisis, or domestic, such as a miners' strike, entails the implementation of a diversification strategy. The internalisation of environmental costs and medium- and long-term environmental sustainability objectives go hand-in-hand with regulatory measures to encourage the use of production technologies with a lower environmental impact. This is the case of generation from renewable energy sources, such as hydro, wind, solar, biomass, geothermal or a diversity of marine technologies. Most of these technologies have high investment costs but low or zero variable costs. Wind and solar photovoltaic plants have

a highly variable output, which can be estimated in advance quite accurately but which is barely dispatchable, except for cutting production.

Today, most electricity generation takes place in large production centres scattered around a country, often at long distances from the major consumption centres. Stations are logically built close to the source of fuel (mines and ports for coal, refineries for fuel oil, regasification plants and pipelines for gas-fired stations, rivers with a heavy flow or head for hydroelectric stations, sites endowed with high wind or solar resources) and on the coast or river banks, since water is a vital coolant in large steam plants. Efforts are usually made to site large power stations at a substantial distance from densely populated areas, due to such issues as pollution or the adverse social reaction to nuclear power plants.

The transmission grid is responsible for carrying the electricity generated in large power plants to the substations that feed the major consumption centres. The enormous size of modern electric power plants is a result of the lower unit costs obtained by increasing their dimensions. This effect, known as economies of scale, has been a factor in the decision to build nuclear plants with an installed capacity of up to 1500 MW, or 500-MW or even larger coal- or oil-fired steam stations, since they are more competitive than smaller plants using the same technologies. The advent of CCGT technology has reversed this trend; as such plants are much more modular, they can be a great deal smaller and still be competitive. Good wind and solar resources are frequently located far from the major load centres, therefore requiring important network investments. On the other hand, distributed generation is experiencing a dramatic rise, with generation units located much closer to consumers, even at their very premises, supported by regulatory measures encouraging diversification, energy savings, such as in CHP, and reduction of environmental impact. Traditional demand nodes in the transmission network may become generation nodes –permanently or occasionally– when the embedded distributed generation in the corresponding local area happens to exceed the local demand.

The generation of electric power in large plants calls for particularly large investments, amortised over the very long term (25 or 30 years) after several years of construction (five, ten or even more in the case of nuclear plants or large-scale hydroelectric stations). The high financial risk that this entails can be assumed by State-owned entities or private initiative if the government provides sufficient guarantees to ensure the recovery of investment and operating costs through regulated tariffs. CCGT technology has changed the economic context substantially by significantly reducing risk: these stations are more flexible, modular and competitive, smaller and therefore quicker to build. All of the foregoing has greatly facilitated private investment in many OECD countries, in the wake of the regulatory changes to introduce free competition in the electricity industry that have taken place worldwide since the early 1990s.

In Africa, the total installed power generation capacity is 245 GW of which 56 MW are renewable generation[14], representing an increase of approximately 50% since 2015. However, faster growth is needed to meet the continent's energy needs, as it was shown

[14] Annual Development Effectiveness Review 2023 / Chapter 1: Light up and power Africa. http://www.afdb.org/sites/default/files/news_documents/ader_2023_-_chapter_1.pdf

in Figures 4 and 5. Currently, more than 75% of electricity in Africa is generated by fossil fuels mostly from diesel backup or gasoline generators (Figure 13). Africa is home to 60% of the best solar resources globally, yet only 1% of installed solar PV capacity. The renewable source that has experienced the most impressive growth in recent years is wind energy – The Status of Wind in Africa report identifies 83 installed wind farms across Africa, providing 9 GW of clean power; CCGT, wind and, most recently, also solar technologies account for nearly all new generation plants in most countries.

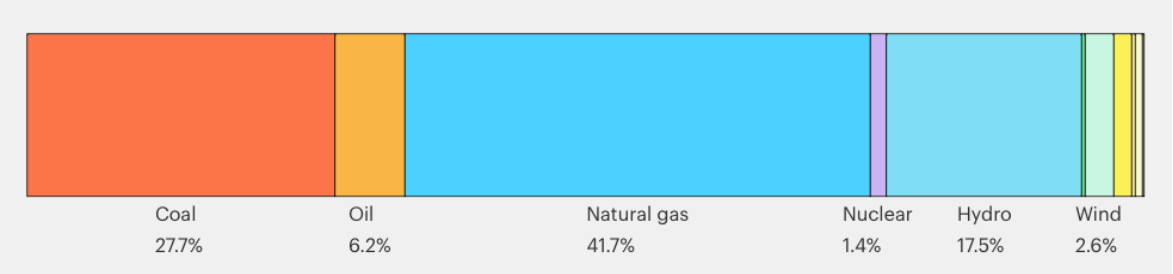


Figure 13. Electricity generation mix in Africa (2021). Source: IEA. https://www.iea.org/regions/africa

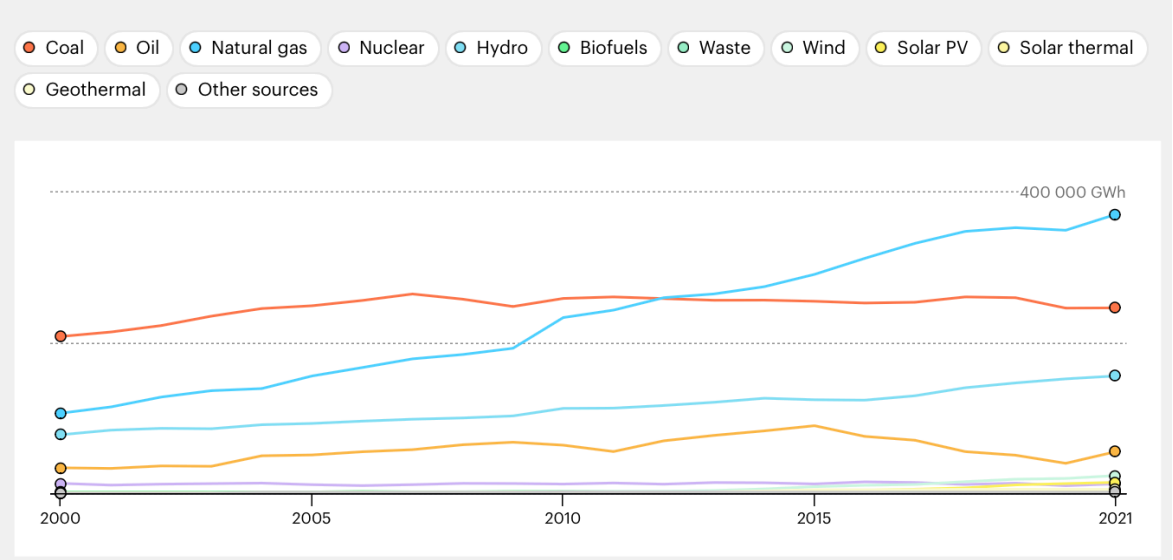


Figure 14. Evolution of electricity generation sources in Africa since 2000. Source IEA. https://www.iea.org/regions/africa

The total electricity production in Africa was 890 TWh in 2021, 3.1% of the world total. In Africa, power systems remain largely underdeveloped at wholesale level – with only 13 countries in the continent having power systems larger than 1 GW, while 27 have grid-connected systems smaller than 500 MW, and 14 have systems smaller than 100 MW.

The biggest producer of electricity in sub-Saharan Africa (SSA), South Africa, is in the midst of a supply crisis. Many of the existing generation plants are either coming to end-of-life or suffering from a lack of maintenance and excessive breakdowns. Across the remainder of SSA, installed capacity remains relatively low. After South Africa (58,095 MW of installed capacity), the countries with the highest installed capacity are Nigeria with 12,522 MW (although only around 3000 MW of this is dispatchable most days), Ghana with 5300 MW, Ethiopia at 4965.5 MW, Kenya with 2819 MW, DRC with 2844 MW, Zimbabwe with 2185 MW, Botswana with 890 MW and Senegal with 1555 MW.

On the other end of the scale Chad has 314 MW of installed capacity, Rwanda has 235.6 MW, and South Sudan generates 120 MW.

3.3. Transmission

The transmission grid connects large and geographically scattered production centres to demand hubs, generally located near cities and industrial areas, maintaining the electric power system fully interconnected and in synchronous operation.

The long-distance transmission of huge amounts of power involves operating at high voltages to cut down circulating currents, therefore reducing cable sizes, voltage drops and ohmic losses in power lines.

The transmission grid is the backbone of the electric power system, interconnecting all its hubs. Its key role in the dynamic equilibrium between production and consumption determines its typically web-like structure, in which every station on the grid is backed up by all the others, to prevent the consequences of possible failures. Ideally, the system should operate as though all generation and all demand were connected to a single bus or network node. It is fitted with sophisticated measurement, protection and control equipment so overall system operation is not endangered by faults, i.e., short-circuits, lightning, dispatch errors or equipment failure.

The transmission grid has acquired particular importance in the new regulatory context that encourages competition, since it is the wholesale market facilitator, the meeting point for market players, as discussed below. The growth of transmission grid capacity, together with the development of connectivity between transmission grids, both within and across national borders, has paved the way for regional- or international-scale electricity markets.

Investment in electricity transmission infrastructure in Africa has relied mainly on public funding, and this trend continues. Looking at key parameters such as the number of kilometres of transmission lines per capita in sub-Saharan Africa, with the exception of South Africa, these countries rank among the lowest in the world. For instance, Brazil has more kilometres of transmission lines than the entire African continent. Improvements are therefore urgently needed, in particular by promoting cross-border interconnections between countries and the participation of private investment.

Power lines

Transmission grid lines consist of steel-cored aluminium conductors supported by towers. Line design is based both on mechanical and electrical considerations. The towers must be sturdy enough to bear the weight of the conductors while maintaining the minimum safety distance between them—and from them to the tower and to the ground as well—imposed by the voltage. The conductors are attached to the towers by a very conspicuous assembly of insulators. Since each insulator can accommodate a voltage ranging from 12 to 18 kV, a typical 400-kV line may need from 20 to 25 such links in the insulation chain. Sometimes two lines run along a parallel route, sharing the same towers; this is known as a double circuit, an example of which is illustrated in Figure 15.

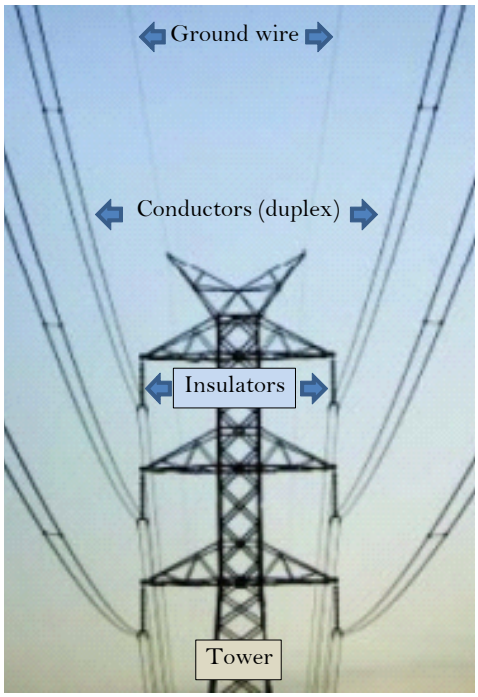


Figure 15. Double circuit line

Electrically, the cross-section of the conductors determines the maximum current they can transmit and therefore the line transmission capacity. The greater the current, the greater are the line energy losses due to the Joule effect. Higher conductor temperature leads to increased conductor expansion and lengthening, resulting in a shorter distance to the ground and greater risk of discharge.

In order to reduce so-called corona discharge (rupture of the insulation capacity of the air around the conductors due to high electrical fields, occasioning line losses and electromagnetic disturbance that may cause interference in communications systems) each phase of the line is generally divided into two, three or more conductors, giving rise to duplex or triplex configurations.

One of the most important line parameters, inductance, depends largely on the relative geometric position of the three phases on the tower. Moreover, the lines induce a capacitive effect with the earth and among the conductors that establishes their capacitance to ground. The inductive effect predominates in lines under heavy loads, which consume reactive energy, whereas the capacitive effect prevails during light load periods, typically at night, when the lines generate reactive energy.

Some transmission lines run underground, mostly in urban areas where the operating voltage is lower and only rarely in the case of very high-voltage circuits. High-voltage underground systems involve the deployment of rather expensive cable technology, since the very short distance between the line and the ground requires the installation of heavy-duty insulators. These lines have a much more pronounced capacitive effect than overhead lines. Submarine cables connect island power systems to the mainland and also other power systems separated by moderate water distances.

In a meshed system like the transmission grid, energy flows are distributed across the lines according to their impedance, pursuant to Kirchhoff's laws. The long distances and the large scale of the power transmitted may reduce the grid's ability to maintain system

operation, favouring the appearance of instability, detrimental to the dynamic equilibrium between generation and demand. This may reduce line transmission capacity to less than its natural thermal limit.

In some cases DC is used instead of AC technology. DC line technology requires expensive converter stations—based on power electronic technology—at both ends of the line to connect it to the prevalent AC system (any required voltage level transformation will also require expensive power electronic devices since the classical transformer device cannot operate in DC). However, this technology presents some advantages—no reactive power flows, higher transmission capacity, lower losses and lower voltage drops for the same voltage and size of the conductors, controllability of the flow, no frequency dependence, reduced stability problems—that has turned it into the chosen alternative in some specific applications such as:

- Long distance lines. The resulting costs may be reduced using DC technology since the price of the converter stations may be largely compensated by the higher transmission capacity of a DC line and the need of additional devices required to control the stability problems that may appear for such long distance in AC lines. The longer the distance the smaller the proportion of the costs of the converter stations referred to the total cost of the line.

- Submarine cables and medium-distance underground cables. The configuration of submarine cables—the conductors should be isolated from the water surrounding them—and in a lower extent the underground cables, induce an extremely high capacity effect that result in a high reactive power generation and a high associated current, that significantly reduces the available transmission capacity of the line. DC technology eliminates reactive power associated problems. Only short distances (like the Strait of Gibraltar) make sense for AC submarine cables.

- Interconnections between power systems with large different security standards. AC interconnections force a joint exposure to disturbances at both ends. DC interconnections allow uncoupling both systems from a security point of view.

- Interconnections between power systems with different frequency values. An AC interconnection is not technically feasible between two systems that operate with different frequency values—for instance Uruguay (50Hz) and Brazil (60Hz)—.

As noted above, environmental considerations have made it increasingly difficult to expand and reinforce the transmission system, resulting in a growing need to make optimum use of existing facilities. This represents an important challenge, since it entails narrowing security margins and perfecting protection, measurement and control logic. With the development of power electronics, new devices have become available that are designed to increase actual line capacity and steer current flow toward the lines with the smallest load flows. Such devices are known as flexible alternating current transmission systems or FACTS.

Substations

Substations, which constitute the second fundamental component of the transmission grid, serve three chief purposes. They are line interconnection buses, transformation

nodes that feed the distribution grids that reach consumers, and centres where system measurement, protection, interruption and dispatch equipment is sited.

Typically, several high-voltage lines feed into the substation, which steps the voltage down and sends the resulting current over the outgoing lower voltage transmission or distribution lines. Conversely, generation substations receive the input power from power plants, raise its voltage and inject it to the transmission grid.

Materially, the substation is structured around thick bars to which the various lines connect. Circuit-breakers –opening and closing devices– ensure the connection and disconnection operations needed for dispatch, configuration changes or the isolation of failed lines or other elements.

A wide variety of substation configurations is used. The number and arrangement of busbars (single, split, double or triple-bar or ring-shaped substations, with or without transfer bars) and the number of circuit-breaker and dispatch devices per outgoing or incoming line determine the configuration type. Increasing the number of such devices raises substation costs but enhances safety, preventing such anomalies as momentary downstream outages due to simple connection operations.

The most representative facility in substations is the power transformer, which raises or lowers the voltage. Transformation is performed electromagnetically through two sets of coils, one at high and the other at low voltage, wound around a ferromagnetic core. The entire assembly is immersed in a vat of oil to ensure optimum conductor insulation. These are very large-scale, expensive, heavy, high-performance facilities, with a very low failure rate.

Many power transformers are involved in system voltage control. In these, the windings are fitted with taps that allow for slight modifications in the turns ratio and therefore voltage step-up or step-down. In some transformers, regulation can be performed during operation, while in others it may not. The photograph in Figure 16 depicts several substation transformers.



Figure 16. Substation voltage transformers

Other substation components include line breaker and switching devices. As noted earlier, substations are the interconnection buses on the grid, where the connections between the various elements are made or severed. This function, which is natural and foreseeable in normal operation, is crucial in the event of failures. Indeed, the system must necessarily be protected from short-circuits occurring in lines or substation bars, since they trigger the circulation of very strong currents that could damage cables and equipment. A fault must then be cleared, i.e., the overcurrent cancelled, as soon as possible and isolated to repair the damaged component; otherwise, the system as a whole may be endangered.

The most sophisticated line breakers are automatic circuit-breakers, which are able to open a circuit when overcurrents occur. The protection devices detect overcurrents and, applying appropriate logic, decide which lines must be opened to clear the fault. Many types of such breakers have been designed, ranging from compressed air (or pneumatic) or magnetic blow-out breakers, for low power and voltage, to oil-immersed circuit-breakers or sulphur hexafluoride (SF_6) devices, for systems with very high voltage and capacity. One special feature of these mechanisms is their ability to open twice in immediate succession. Since many faults have a very short duration, because the cause of the outage disappears spontaneously (where due to a faulty contact or a contact that is burnt out by the current flow, for instance), the system usually attempts to reconnect the circuit-breaker automatically, in case the cause of the fault has in fact been eliminated. If not, the breaker will re-open. Breaker design is such, however, that their position (open or closed) cannot be ascertained by mere visual inspection.

Once the fault is cleared and identified, the damaged area must be electrically isolated to reconnect the rest of the elements initially shut down by the circuit-breaker. This is done with local disconnectors, used to open or close a line when the current is negligible. Their function, therefore, is not to cut off the current, but simply to visibly isolate a section of line or a device, machine, substation bar or any other element so it can be handled for repair or maintenance in full confidence that it is not live. The operator opens the circuit manually after confirming that the circuit-breaker has worked properly and removed voltage from the entire area in question. Several types of disconnectors can be used: rotary, sliding, column rotary and pantographic.

Lastly, the line breakers used in grid dispatching have a break capacity on the order of the nominal intensity of the current in the circuit or line they are designed to open or close. Consequently, they do not open in the event of a short-circuit. Air-break switches, automatic air switches, automatic gas circuit-breakers, magnetic blow-out switches and oil or hexafluoride switches are some of the protection devices used for this purpose.

Today some substations are entirely immersed in hexafluoride. Although more expensive, this arrangement considerably shortens the distance between bars, conductors and cables, and this is particularly attractive for urban environments where square footage is costly. Such substations are, moreover, extremely safe. Most are sited underground.

3.4. Distribution

On-grid distribution.

Lower-voltage networks branch off the high-voltage grid from the substations in multiple directions to carry electric power to even the most secluded areas. The structure of this system, generically called the distribution grid or network, is very different from the transmission grid structure.

The upper or regional level, which actually forms part of the transmission grid, has an open web or loop configuration and operates at somewhat lower but still very high voltages, typically 132, 66 and 45 kV. The substations fed by this part of the grid step the voltage down to 20, 15 or 6.6 kV, splitting power off into the distribution grid per se, which is the part of the system that supplies power to the end consumer.

The structure of this medium-voltage network may vary, but its operation is always radial. Substations normally house circuit breakers that protect the so-called feeders, i.e., lines running to other transformer stations where the voltage is stepped down again to supply low-voltage power. The low-voltage lines, which may be 400, 230, 130 or 110 V, depending on the country, supply residential customers, wholesalers and retailers and the like. Consumers connect into the system at the voltage level best suited to the scale of their consumption.

Distribution grids in urban areas, where high load densities are concentrated in small areas, generally run underground. While it is more costly to lay and repair underground cables, the distances involved are much shorter than in rural networks. Urban systems usually have a meshed structure for greater reliability, but by and large these networks operate radially, with circuit-breakers normally open for ease of operation and to reduce eventual short-circuit currents. The reliability level is typically high, due to the short distances, the undergrounding and the meshed network configuration that provides redundancy.

In rural areas, distribution networks are generally radial and consist of less expensive overhead lines because load density is not high and space is not an issue. There is less redundancy in the supply to any given load and the reliability levels are typically lower than in urban networks. One problem encountered is that reliability declines as the distance from the substation increases. For this reason, rural networks are sometimes designed to provide downstream emergency supply in the event of failures. The voltage drop problems that also arise in these networks are solved by placing taps on the transformers and installing capacitor banks that supply reactive power.

Distribution networks, which comprise thousands of kilometres of wires, are subject to more frequent failure than the transmission grid and their structure is less redundant; this means that most of the supply outages that affect the end consumer originate in the distribution network. In terms of investment plus operation and maintenance costs, distribution accounts for a large share of total system costs, which normally is several times higher than the share of the transmission grid.

The global performance of electric utilities in Africa, and distribution in particular, is tracked by the Energy Sector Management Assistance Program (ESMAP) of the World Bank Group in the program "Utility Performance and Behavior in Africa Today"

(UPBEAT)[15], to facilitate greater understanding of the status quo of the utilities from the financial, operational, transparency and accountability viewpoints. Operational performance was already commented in the section of quality of service (reliability) and network losses (energy efficiency). The UPBEAT program concludes that the financial performance of most utilities is precarious, with a widening mismatch between the operating and debt service costs and the revenues from the tariffs. About one in three utilities recover their operating and debt-service costs. If subsidies are excluded, the ratio is one in four. Of the 27 utilities that recover operating costs and debt service, 8 require operating subsidies to do so. Of the 45 utilities that do not recover operating and debt service costs, 35 utilities do not recover costs even with subsidies included. These utilities are loss-making and many have negative equity. Most utilities have significant room for improving transparency of their reporting and communication with their customers and stakeholders.

Off-grid distribution.

More than 80% of Africans without electricity access live today in rural areas. It is widely acknowledged that the current electrification pace is woefully slow to achieve universal access by 2030, as stipulated in the SDG7. Without additional measures, 565 million people will still be without access to electricity in 2030,[16] with very different projections for individual countries.

Many countries, in Africa and elsewhere, have created rigorous techno-economic geospatial electrification plans, which show in great detail the least-cost path to universal electricity access for prespecified levels of demand and reliability of supply.[17] The majority of these plans show that the solution of minimum cost typically consists of a fraction of customers[18] to be supplied by extending the main grid, while others must be connected to minigrids or supplied with standalone systems.

For sub-Saharan Africa it has been estimated that more than 200,000 minigrids will be necessary to supply approximately 32% of the people that will be gaining access until 2030 assuming that universal access is achieved, with a cost of about 127 billion (10^9) US dollars.[19] In general, electricity supply with minigrids is the least expensive solution for

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[15] https://blogs.worldbank.org/en/energy/new-tool-measure-and-help-improve-performance-africas-electric-utilities-upbeat-data

[16] International Energy Agency (IEA), "Africa Energy Outlook", 2022. https://www.iea.org/reports/africa-energy-outlook-2022

[17] Ibid. See also the MIT/Comillas Universal Energy Access Lab https://universalaccess.mit.edu/#/main for the electrification planning approach.

[18] The term "customers" is used instead of the more common "consumers", since a rapidly increasing number of agents that are connected to the grid can generate and store energy, in addition to consuming it.

[19] International Energy Agency (IEA), "Africa Energy Outlook", 2022. https://www.iea.org/reports/africa-energy-outlook-2022, as well as Mattson, B., Sinha, M. and Brent, W. "Scaling solar hybrid minigrids: An industry roadmap", 2022. Husk Power.

clusters of population with the right combination of low aggregated potential demand and sufficient distance to the existing distribution grid. Even for population clusters close to the grid or already connected to it, minigrids are the only workable solution when the incumbent distribution company lacks the resources or the incentives to connect more customers and to provide a reliable supply.

The added value of minigrids must not be underestimated. Minigrids can be deployed quickly, basically anywhere. If properly designed, minigrids can be integrated in the main grid if it happens to arrive to their location. Minigrids can provide reliable power 24 hours per day not only for residential demand, but also for productive and community uses. Minigrid developers are usually more inclined than the incumbent distributors to engage with end customers in promoting demand growth for productive and community uses, as their income critically depends on the volume of demand and the economic situation of their customers.

On the other hand, the Off-Grid-Standalone Solar (OGS) industry is increasingly recognised as vital to achieving global energy access, given that OGS products can be deployed faster than main grids and can also service small and disperse loads more cost-effectively, as well as provide backup support to individual customers with unreliable supply from the main network. This is evidenced by the growing number of countries that have incorporated and continue to integrate OGS systems into their electrification plans.

By 2030, OGS systems are projected to account for 41% of the necessary electricity access, based on geospatial least-cost modelling of universal energy access scenarios. In some regions such as Central Africa, OGS products are projected to be the least cost solution for 81% of new connections between 2020 to 2025 because grid infrastructure is underdeveloped and unlikely to scale up fast enough in the next few years.[20]

Whereas the figures of public and private investment in OGS indicate some progress in funding for this critical sector, they are far below the massive investment required to increase electricity access, particularly if SDG7 is to be achieved. It is estimated that the OGS sector requires almost $26 billion in financing.[21] The financing channels are not acting fast enough to address the funding gaps in the OGS market, largely because of a mismatch between the structure of these instruments and the underlying business models of the companies in the sector.

It is desirable that a significant proportion of the funding required by the OGS sector comes from private investors, who will also be involved in customer service. This will

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https://huskpowersystems.com/new-roadmap-says-minigrid-industry-needs-10-companies-with-10-times-current-scale-to-achieve-universal-energy-access-and-sdg7-2/

[20] Lighting Global/ESMAP, GOGLA, Efficiency for Access, Open Capital Advisors (2022), Off-Grid Solar Market Trends Report 2022: State of the Sector https://www.esmap.org/Off-grid_Solar_Market_Trends_Report_2022

[21] ESMAP. 2020. Funding the Sun: New Paradigms for Financing Off-Grid Solar Companies. Washington, DC: World Bank. https://documents1.worldbank.org/curated/en/447971581689878643/pdf/Funding-the-Sun-New-Paradigms-for-Financing-Off-Grid-Solar-Companies.pdf

only be possible if business models for off-grid solar systems can be defined that are financially viable and can maintain this condition permanently, i.e., if the business models are sustainable. In addition, it is vital that these business models can be scaled up to the necessary dimension, both in terms of the required financing and the technical and managerial capability of the off-grid solar companies to deploy all the off-grid solar systems identified in integrated electrification plans.

Off-grid solar companies encounter obstacles in their businesses that could be mitigated by a more adequate regulatory environment. Off-grid solar systems could replace most of the existing diesel back-up generators if the correct regulatory measures would be implemented. Off-grid solar companies cannot reach all the populations they should and provide a truly sustainable service without a sound regulation framework for OGS systems able to attract the necessary investment and that also considers the other modes of electrification.

4. ELECTRIC POWER SYSTEM MANAGEMENT

Electric power system management is an extremely complex undertaking, due to the breadth of the task, which covers technical, economic, regulatory, social, business and environmental factors. It broadly encompasses investment planning and system operation, both closely conditioned by the technological characteristics of the power system.

The planning and operation of electric power systems are the result of a complex chain of decisions. The first link comprises long-term provisioning (capacity expansion, long-term fuel contracts); the second, medium-term planning (hydroelectric management, facility maintenance scheduling, shorter-term fuel contracts); the third, short-term unit commitment (generating unit connection, reserve operating capacity); and the fourth, actual system operation (generating unit dispatching, frequency regulation, response to possible emergency situations). This decision-making process is supported by computer models, fed by highly sophisticated data acquisition and communications systems. Today's computational resources make it possible, for instance, to precisely calculate the marginal cost of meeting demand (i.e., the cost of one additional kWh) at any given point in the system at a given time, taking into account the chain of decisions outlined above.

Decisions affecting electric power system expansion and operation should be guided by criteria of economic efficiency, in order to minimise the cost of delivering an acceptable quality of supply to end consumers. Nonetheless, constant account must be taken of technical considerations to ensure the material feasibility of supplying electric power, which is arguably much more vital to this industry than to any other one, given its specific characteristics. As discussed below, the importance of such considerations grows as the time lapsing between decision-making and implementation narrows down to real time, when the distinction between economic and technical factors blurs and no sharp line can be drawn between them.

Given the size, dimension and complexity of the problem, the entire decision chain must be rationalised and organised. This is achieved by ranking expansion and operating functions chronologically. In longer-term decisions, for example, where future uncertainty and economic criteria carry considerable weight, a rough approximation of system technological behaviour suffices. Such decisions successively guide shorter-term

decision-making, in which the technical specifics carry much greater weight, culminating in real-time operation, where system dynamics must be analysed in full detail, millisecond by millisecond[22].

The criterion underlying the entire decision-making process is the maximisation of social welfare in the production and consumption of electric power. This involves two fundamental concerns. The first is the effort to minimise the entire chain of costs incurred in providing the service, including both investment and operating costs. The attainment of an inexpensive service is not the only factor used to measure social utility, however. The quality of supply must also be satisfactory. Social utility would be low for both industrial and residential consumers if service were cheap but plagued by constant outages. Due to a number of uncertainties, including rainfall, real demand growth, generating, transmission and distribution equipment failures or lack of wind or solar input, outage-free service cannot be guaranteed in future scenarios. In other words, some likelihood will always exist of failure to service all of the demand at all times, which is a measure of system reliability. It is equally clear, however, that such likelihood of failure can be reduced by investing in more facilities and operating more conservatively. Increased reliability entails higher costs.

For this reason, the first criterion referred to above, cost minimisation, must be qualified to accommodate the second criterion, which reflects system reliability. This can be built into the decision-making process in a variety of ways. One is to set a minimum reliability threshold based on past experience and social perception of the concept, measured in terms of the likelihood of an interruption of electric power supply or some other similar indicator. A more soundly based method consists of attempting to quantify the financial harm caused by service interruptions on the basis of consumer utility. Building this factor into the cost minimisation process as one more expense to be taken into account is actually a way of maximising the social utility of the service. The inherent difficulty in this second approach lies in quantifying "utility", which may vary from one consumer or individual to another, and which cannot be clearly measured, although efforts have been made in this respect by conducting systematic consumer surveys specifically designed for this purpose.

Reliability is a factor that involves the entire decision-making process, from long- to short-term. Service interruptions may be due to investment-related issues, for example, if system installed capacity is insufficient to meet demand, perhaps because demand growth has been unexpectedly steep, hydrological conditions particularly adverse, transmission capacity lacking or the implementation of new investment delayed. They may also be caused by operating inefficiencies, such as poor reservoir management, lack of immediate response to failures in units or lines due to a shortage of reserve capacity, or by real-time system stability problems. Therefore, in nearly all the decision-making scenarios reviewed below, cost and reliability factors must be brought into balance in the decision

[22] The anticipated –sometimes already existing– massive presence of intermittent generation, demand response, electric vehicles or distributed storage, creates a significant impact of the sort-term behaviour of the power system on capacity expansion planning. On-going research tries to introduce short-term modelling capabilities into long-term capacity expansion or strategic analysis.

reached. The term adequacy is generally used to describe long-term reliability, while security refers to short-term operations.

There is no standard way to organise electric power system planning and operation. The solution to such a complex problem nearly always involves breaking it down into simpler parts and all the approaches taken to date involve, in one way or another, time-scaled hierarchical decomposition. Decision-making is ranked by time frame, and the respective functions are scaled accordingly. The highest level comprises the longest-term decisions, which tend to address strategic problems. The solutions adopted are then passed on to the lower levels, delimiting their scope of action. At successively lower levels of the scale, as functions approach real time, the optimum solution must be sought within the restrictions imposed by the problem and by the guidelines handed down from the higher levels. This structure, abstractly defined in this section, is described in greater detail in the items below[23].

4.1. Two power system management paradigms: centralized planning versus decentralized market-based

All of the functions outlined above need to be addressed within the regulatory and legal context of each country, which affects how these activities are carried out and who the decision makers are. With the profound regulatory changes undergone in the power industry in most of the world, any attempt to describe the economic environment should cover both the traditional scenario, still in place in many countries, as well as more liberalised situations. Each country handles the organization of its power system according to its own characteristics, but, in general terms, two major regulatory approaches to maximize the social welfare can be distinguished. They are described with a variety of terms: traditional vs. liberalized, centralized vs. decentralized, centrally planned vs. free-market oriented or regulated vs. deregulated[24], among others.

In order to provide a first pass at how decision making happens in a power system and how it depends on the underlying regulatory regime, the discussion in the next sections will be first based on the general assumption of a single decision-maker in a vertically integrated utility under the traditional regulatory framework of a regulated monopoly with cost of service remuneration: the traditional centrally-managed approach. Then, at the end of each section, the most salient differences that restructuring and liberalization have introduced in the decision making process of electricity companies will be succinctly described: the market-based decentralized approach.

Let us start by briefly describing the main general characteristics of both approaches.

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[23] As mentioned before, this classical viewpoint is becoming increasingly challenged by the new developments in power systems: distributed generation, active demand response, distributed storage or electric vehicles.

[24] The term "deregulated" is a misnomer, since restructured and liberalized power systems are typically subject to a very detailed and complex regulation. The regulatory change that has taken place in the power sector of many countries during the last three decades is more a restructuring and re-regulation than a deregulation. The term "deregulation" is used to mean a departure from the heavily regulated monopolies under traditional regulation.

The traditional centrally-managed approach

Under the traditional regulation scheme, electric utilities are awarded territorial franchises or concessions where they supply electricity with a regulated monopoly business model. The utilities are vertically integrated, i.e. they own and operate all the generation and network assets in their franchised territories, they have the obligation to supply any requested demand by the consumers in their respective areas; and they plan and implement the expansion of production and network capacity under the guidelines and authorization of the regulatory authority. Centralized planning of operation and investment must seek the minimization of costs—which in principle must include the consumer costs of loss of electricity supply—and a satisfactory reliability level (sometimes capacity expansion planners or system operators impose reliability-based constraints) and environmental impact. These utilities may reach voluntary agreements to exchange electricity with the neighbouring ones. In many countries a single publicly owned utility has supplied the entire demand within the national territory[25].

Under traditional regulation the consumers are mandatorily assigned to the utility serving the area where they are located. Since the consumers have no option to choose supplier, they are protected by the regulator, which may establish minimum standards of quality of service and also determines the remuneration of the utilities. The remuneration is based on the incurred cost of service, which includes a reasonably attractive rate of return on the invested capital. Diverse efficiency incentives have been used in some cases.

The market-based decentralized approach

Electricity industry restructuring has brought profound change to electric power system operating and planning. Industry liberalisation has gone hand-in-hand with the dramatic decentralisation of these two tasks. The electricity industry's new structure is based on the introduction of competition and the institution of electricity markets (Joskow and Schmalensee, 1984; Schweppe et al., 1988; Sioshansi and Pfaffenberger, 2006; Hunt and Shuttleworth, 1996). Wholesale markets for electric power open to all generators, both incumbents and new entrants, as well as to all large consumers and consumer-serving entities, have been established in countries adopting the new model. The core of this wholesale market is typically a spot market for electricity, which serves as a reference for medium- and long-term contracts of different types, and even for organised markets for electricity derivatives. The agents trading on such markets are generators, eligible consumers (i.e., those consumers allowed to choose supplier and with sufficient size to participate in the wholesale market) and different categories of supplier companies, acting on behalf of non-eligible consumer groups or eligible consumers, or simply as strict intermediaries.

Liberalisation can be also extended to the retail level, with all consumers, regardless their size, being free to choose a retailer (also termed "supplier") on the basis of the available commercial offers. This requires separating or "unbundling" the activities of *distribution* (in charge of developing, maintaining and operating the network infrastructure that

[25] In Europe, for instance, prior to the 1990s' liberalization process, most major countries (except for Germany and Spain) had just a single publicly-owned electric utility.

connects all customers to the main grid) and *retail* (consisting of purchasing energy at wholesale level and selling it to the end customers), since the former must be regulated as a monopoly and the second is performed under unregulated competitive conditions. A basic tenet of orthodox regulation is not to mix regulated monopolies with commercial – and therefore risky – activities. In Africa, most of the American continent and many other countries retail competition does not exist and both activities – distribution and retail – are jointly performed by a single company, the "disco" or distribution company, or the distribution segment of the vertically integrated utility. Unbundling distribution and retail is mandatory in the countries of the European Union.

With the exception of the supply of electricity with off-grid solutions – i.e., minigrids and standalone systems – distribution and transmission networks are necessary to get the electricity generated in the power plants to the end customers. From a regulatory perspective electricity networks are natural monopolies whose remuneration and performance objectives must be established by a regulatory authority. These networks do not have the technical and economic characteristics that would permit them to provide their services under a market-based regulatory regime. Consequently, under a market-based regime transmission and distribution of electricity must be unbundled from the competitive activities that they relate with, namely, transmission from large generation and distribution from retail. Because of this reason, the organisation and the ownership structure of the power sector nearly always have to be modified (via an unbundling process) before competition mechanisms can be implemented.

Under this decentralized approach, system operation and expansion are the result of individual company decisions based on the maximisation of business earnings, either under organised tendering or through private electric power supply contracts. Economic and financial risk and anticipated returns on investment, instead of the traditional cost minimisation criteria, drive decision-making. The challenge for administrative and regulatory authorities is to design liberalised market rules that ensure that the strictly entrepreneurial behaviour of each market player leads to maximization of social welfare – i.e., overall minimisation of system costs while respecting reliability and environmental objectives and constraints–, reflected in the prices charged to final consumers.

Real-time system operation, however, continues to be a centralised task. A centralised organisation, usually called the System Operator, oversees system safety. Ensuring real-time technical viability of the system calls for highly sophisticated co-ordination of all the available resources. This in turn requires absolute independence from the various actors' individual interests.

Under this regulatory approach the electric power system operation is viewed, therefore, from a wholly different viewpoint. New functions, responsibilities and ways to address the decision-making process have arisen, along with changes in the roles played by each of the agents involved.

4.2. Planning and investment

Traditional centrally-managed approach

The first-level of decision-making takes a long-term approach, projecting anywhere from 2 or 3 to 10, 15 or more years into the future, to define generating plant and

transmission/distribution grid investments. The process involves determining the type, dimensions and timing of new generation and network facilities to be installed, based on several factors. These include demand growth forecasts, technical alternatives and costs, estimated fuel availability and price trends, reliability criteria adopted, environmental impact constraints, diversification policies and objectives relating to dependence on the foreign sector. Such distant horizons are necessary because the (very large) investments involved are justified on the grounds of the earnings over the service life of such facilities, which may be up to 20 or 25 years for solar photovoltaic plants, from 25 to 40 years in the case of steam power stations and much longer for hydroelectric plants.

With such distant horizons, uncertainty is obviously a key determining factor. A whole suite of scenarios must be addressed, the respective probabilistic assessments conducted and the most suitable criteria adopted, such as minimisation of expected average costs, minimisation of regret or minimisation of risk, taken as the variance of the cost distribution function.

For the same reason, it makes no sense in this type of studies to evaluate the technical behaviour of system operation in detail, since it is neither feasible nor sensible to seek accuracy in the assessment of operating costs when the process involves much greater levels of financial uncertainty.

One of the chief requisites for the process is a good database, which must contain information such as updated data on technologies as well as historical series on demand, hydrology (rainfall), equipment failure rates and so on. The long-term demand forecast built from these data adopts the form of a probability curve that determines system expansion needs. As indicated above, the hourly demand profile is as important as total demand in this regard, since the choice of technologies largely depends on this information. The next step is to determine the generating plant expansion required to meet demand under terms that seek to minimise the anticipated costs over the entire period considered while taking the aforementioned strategic criteria into consideration. Such costs include the fixed investment outlays plus operating costs throughout the entire period, which obviously depend on the type of investments made. Simulation and optimisation models are often deployed as an aid in such estimates. Because of the scale of the problem posed, decomposition analysis techniques are generally used that run iteratively and alternatively between two modules, one specialising in expansion cost calculations and the other in operating costs, exchanging information between the two as necessary until the results converge.

Decisions to enlarge the transmission grid have traditionally depended on new generation plant investment needs and demand growth. This is because considerably less investment and time were needed to build grid facilities than generating stations. The situation has reversed now, with the short installation times of wind, solar and CCGT plants, while transmission facilities have to face increasing siting difficulties. Ideally, once the new plant sites and the consumption and production growth rates are estimated, grid expansion is determined, comparing the necessary investment costs with the benefits accruing to the system: lower operating costs, smaller system losses and greater reliability in meeting demand. The decision process is also affected by security criteria that ensure that supply will not be subject to interruptions due to grid reinforcements or other technical aspects, such as voltage or stability issues. In reality transmission planners sometimes have to initiate the construction process based on their best estimates

of generation and demand growth. Expansion decisions are, naturally, dynamic over time, since they must be periodically adjusted when real data on demand growth, technological innovations or fuel purchase terms modify the assumptions underlying the initial expansion plans.

Distribution network planning has the primary objective of connecting all consumers and distributed generators to the grid, while meeting prescribed reliability targets. The remuneration of this network activity is typically determined by the regulator, on the basis of the estimated cost of service, plus incentives related to reduction of network losses and achievement of quality of service objectives. Both the planning and regulation tasks will become more difficult with the increasing presence of distributed generation, local distributed storage, electric vehicles and demand response.

Most African countries have not achieved universal electricity access yet and many are far from meeting this goal soon. Thus, electrification planning takes a new dimension and it is necessary to determine the combination of the three modes of electrification – grid extension, minigrids and standalone systems – and the path of deployment that can meet the objective of universal electrification at least cost by a prescribed time.[26]

Market-based decentralized approach

Restructuring and liberalisation have completely revolutionised generation expansion planning, since it is now left up to each potential investor the evaluation and the final decision on the advisability of investing in new generating facilities, based on individual cost-benefit analysis.

Each new investment is studied from the perspective of its estimated net profit over its lifetime, although in practice the evaluation is realised over a period not exceeding ten years. The outcome of the study strongly depends on the behaviour of the wholesale electricity market: fuel prices, demand levels, other new investments, market prices and the like. Financial risk assessment plays a crucial role in such reviews because it is the key to obtaining adequate financing. Risk management and the formulation of contracts to supply power and to hedge against uncertainties, along with access to futures markets and options, are elements of great importance in this new context.

Whilst transmission grid planning continues to be centralised, the perspective has changed and today's decisions are subject to much greater uncertainty. The basic planning criterion, namely optimisation of the social utility of electricity production and consumption, remains unvaried. But such utility no longer necessarily adopts the form of minimisation of production costs, but is based, rather, on the maximisation of the aggregated benefits (surpluses) of all the individual actors: the utility of electricity consumption less the acquisition cost, for consumers; and the revenues from the sale of electricity less generating costs, for producers.

Moreover, the uncertainty surrounding the transmission planner's decisions has risen dramatically. Traditionally, the grid was planned on the basis of prior results of the expansion of generating capacity, information which in an environment of free

[26] MIT/Comillas Universal Energy Access Lab https://universalaccess.mit.edu/#/main

competition is not compiled centrally or *a priori*, but rather is the result of business decisions made individually by the different players at any given time.

Consequently, neither the amount nor the location of new generating units is known for certain when the grid is being planned. Furthermore, the time that may lapse from when the decision to build a line is made until it becomes operational is growing longer, due in particular to difficulties in permitting regarding environmental impacts and territorial organisation. Together, these two factors render transmission network investment planning very complex. In addition, new generation plants should be carefully sited, taking current network capacity into consideration because construction lead times are often longer for the transmission grid than for the power stations themselves.

Transmission investment has an impact on both generation plant competitiveness and market power. The former complicates decision-making. Because of the trend to create supra-national markets and the appearance of large-scale renewable production facilities, transmission planning has become a critical issue whose geographic scope has been substantially enlarged.

Distributed generation, electric vehicles, storage and demand response may take place within both the traditional and liberalized frameworks. Therefore, no significant changes are expected in the activity of distribution planning because of the choice of regulatory paradigm.

Electrification planning and the means to enforce the plan are also needed under a market-based approach, because without a regulated approach under cost-of-service regulation universal electricity access will never be achieved. The incumbent distribution companies will not extend the grids in rural areas as required by the national electrification plan. Communities that cannot afford the cost of supply of minigrids will be left behind, as well as those customers separate enough from clusters – so that the least cost solution for them is not a minigrid but an individual system – who cannot pay the cost of that individual system. The principle of remuneration based on the cost of service must be the bedrock upon which to build viable business models for the incumbent disco, the minigrid developers, and the providers of solar home systems.[27]

4.3. Operation planning

Traditional centrally-managed approach

Once the installed capacity of generation and network is defined, the medium and long-term operating plans for the production facilities must be established. For a one- to three-year horizon, depending on the system in question, such planning involves determining the best unit and grid maintenance cycle programme, the most beneficial fuel purchase policy and the most efficient use of power plants, subject to primary energy limitations –

[27] The proof of this statement can be found in those countries – many of them in Latin America, with a medium low income per capita – that for many years have stayed with a percentage of unelectrified population (poorer than the country's average and in faraway places) – of 5% or lower.

hydroelectric stations in particular–, to the availability of wind and solar resources or to yearly production restrictions for environmental reasons.

Electricity generating plants are sophisticated systems with thousands of components that must be checked periodically to prevent major and sometimes hazardous failure and ensure plant efficiency from a technical standpoint. Operation of conventional steam plants is usually interrupted around twenty days a year for this purpose. Nuclear plants need to have their fuel (uranium bars) recharged once every year and a half approximately, so maintenance tasks are programmed to concur with such plant shut-downs. Electric power lines and transmission and distribution grid components located in substations also need upkeep, such as the replacement of faulty insulators or their cleaning to prevent loss of insulation power. Although the technology to perform these tasks on live lines is becoming more widely available, most of these operations are conducted on de-energised facilities for obvious safety reasons, which involves disconnecting particular substation lines or areas. This, in turn, requires careful maintenance planning to interfere as little as possible with system operation.

Fuel management also calls for careful planning, sometimes far in advance. Once input needs are defined, fuel purchases, often on international markets, must be planned to buy at the most advantageous price, make shipping and storage arrangements and take any necessary logistical steps to ensure that stations do not run out of fuel.

Finally, the use of water in hydroelectric plants must also be planned as if it, too, were a fuel. In fact, water can be regarded as a cost-free fuel in limited supply. Therefore, its use must be scheduled in the most beneficial manner. Run-of-the-river stations require no planning, but decisions are imperative when there is an option to either generate energy or store water for production at a later time; therefore, while ideally free, water actually has an opportunity cost. Depending on the size of the reservoir, such decisions may cover time frames ranging anywhere from a single day to several weeks, months or even years for the largest reservoirs. The operation of stations whose management and regulation extend over several months should be planned on a yearly or multi-yearly basis. Since the logical aim of such planning is to attempt to replace the most expensive thermal production, this type of planning is usually termed hydro-thermal coordination. A similar approach is taken for any other technology subject to restrictions on use that limit production in a given time frame, typically seasonal or annual. One example would be the existence of mandatory national fuel consumption quotas or yearly pollution limits.

Market-based decentralized approach

Under market conditions the objective of the plant's owner is to maximise the margin of revenues over production costs. Not surprisingly, the two considered regulatory frameworks ideally lead to the same operation schedule for the generating plants. The various agents –producers and consumers– participating in the electricity market must attempt, under the liberalised scheme, to optimise their medium- and short-term individual operational decisions. Generators, in particular, must perform the following tasks:

- To formulate medium-term economic forecasts: revenue projections and yearly budgets.

- To provide support for the aforementioned long-term functions: contract management and determination of long-term business strategies.
- To provide support for short-term functions, in particular the formulation of bids in the daily and ancillary services markets, by making explicit the boundary conditions for these short-term decisions: available hydro resources or fuel quotas for the considered period, environmental restrictions, fuel costs and scheduled availability status of conventional plants.

The decision support models for generators competing in electricity markets must seek the maximisation of the net profit of each agent. This requires making use of theoretical microeconomic and game theory-based concepts into the model. In the former case, markets are seen as dynamic elements that reach certain points of equilibrium characterised by the various agents' production structures. In the latter, markets are viewed as the result of a game in which the established rules ultimately impose a strategy to be followed by each agent in response to the reactions of all the others.

4.4. Unit commitment and dispatch

Traditional centrally-managed approach

Short-term decision-making typically refers to a weekly horizon, at most, i.e., from one or a few days up to one week. It involves determining the production plan for hydroelectric and steam power stations on an hourly basis for each day of the week. This plan must also abide by the instructions received from the immediately higher decision level described in the preceding section, in connection with factors such as maintenance work, weekly hydroelectric management, emissions plans or fuel quota management.

At this level, system details are extremely important, and account must be taken of aspects such as steam plant generating unit start-up and shut-down processes and costs, wind and solar forecasts (since quick and significant changes in wind and solar output create ramps in production that the rest of the plants have to meet), hydrological constraints in river basins, stations in tandem arrangement, demand chronology profiles (which call for accurate production monitoring) and generating capacity to be held in reserve to respond immediately to fortuitous equipment failure.

The ability to vary steam power station output is limited by the technical characteristics of the respective generating units. It takes an inactive station a certain minimum amount of time to recover operational status, which is primarily determined by the time needed to heat the boiler to a suitable temperature. Therefore, this minimum lead time depends on how cold the boiler is, or in other words, the amount of time it has been turned off. Conventional coal fuelled steam power plants may need from eight to ten hours if the boiler is completely cold. Gas fuelled plants are more flexible, with lead times of a few hours for CCGTs or even only a few minutes for single cycle gas turbines. In addition to this, one must include the impact on the maintenance costs of each start-up process, a value that is typically specified in the maintenance contracts for each individual plant. As a result, the cost of starting up a steam power station may be significant and can be quantified as the price of the fuel that must be unproductively burnt to heat the boiler to the appropriate temperature plus any associated effect on the maintenance costs. For this reason, even if demand declines substantially, it may not be cost-effective to disconnect

certain steam stations at night, but rather to maintain a minimum production level. This level, known as the plant's minimum load, is generally relatively high due to boiler combustion stability requirements, on the order of 30 to 40 % of the station's maximum output. Depending on the findings of cost-effectiveness studies, a decision must be made on whether it is more economically sound to start and stop the station every day (daily start-up cycle) or to shut it down on the weekends only (weekly cycle), or simply never shut it down, as in the case of nuclear stations. Sometimes it may be more efficient to keep the boiler hot but unproductive. Boiler thermal constants and their limits likewise impose constraints on how quickly steam plant output rates can be modified, which are known as upward or downward ramp constraints. Therefore, careful planning of unit start-ups and shut-downs is required, a problem known as unit commitment.

This decision is also strongly influenced by daily or weekly hydroelectric management, as well as system reserve capacity requirements. Hydroelectric stations are much more flexible than thermal power plants, with practically zero lead time, no significant start-up costs and virtually no real limits on modulating generating capacity. The optimal scheduling of hydroelectric production to meet variations in demand takes a number of considerations into account: higher-level decisions on the amount of water resources to be used in the day or week, the most cost-effective hourly distribution (weekly or monthly hydro-thermal coordination) and technical constraints on steam plant units. Hydroelectric generation and its use of water in reservoirs must likewise comply with possible restrictions imposed by water management for other purposes, including irrigation, fauna, and minimum reservoir and river flow levels, as well as other conditioning factors typical of water works and their configuration: canals, pipelines, reservoir limits and reservoirs operated in tandem.

Here also, reliability criteria play a role in decision-making. Provision must be made for the immediate replacement of any plant in the system that may reasonably be expected to fail or for the ability to respond to transmission grid failures. This translates into the start-up and connection of new units; although these may be unnecessary under normal conditions, the system would not otherwise be able to generate power for several hours if needed to cover emergencies.

Market-based decentralized approach

Although electricity markets may be organised in a variety of ways, a series of short-term organised markets usually coexist with private bilateral agreements between producers and consumers. Generating stations' short-term output is determined from both market clearing and bilateral arrangements. Organised markets, typically including a day-ahead market, several intraday markets, a balancing market and an ancillary service market, play a central role as they provide a transparent and publicly available price reference for energy and reserve services.

The day-ahead market is usually the most important market in terms of trading volume. Consequently, a substantial share of a company's short-term operations tends to revolve around the preparation of daily bids. This process is governed by higher level and longer term strategic decisions. As such, it is informed by output guidelines deriving from analyses covering longer terms and its role consists of setting market prices on a day-to-day basis. In some power systems (those using what is called "complex bids") all costs are declared in the bids. Other markets use "simple bids", just specifying quantity and price;

in this case the generators need to estimate the future short-term prices and the dispatch pattern of their plants, as a guide for decisions on the internalisation of steam generating unit costs and the utilization of their hydro resources. These are complex decisions that are generally supported by sophisticated market simulation and optimization models.

4.5. Real-time operation

Traditional centrally-managed approach

Security criteria acquire an increasing importance, even dominating economic criteria, in the design and implementation of real-time operating functions. The economic component of these processes is defined by higher-level decisions, where the economic aspects of reliability should always be kept in mind. Supervision, control and monitoring ensure the technical viability of the immense and dynamic electric power system, as described above. The concerned functions and facilities are organised by levels or layers.

On the first level, the components that comprise the system backbone, i.e., generating stations, high-voltage grids and large substations, are centrally monitored and controlled from a control centre that supervises system status in real time; the generating plant, line flows, voltage levels, system frequency and the like are checked by remotely transmitted and duly processed measurements.

This supervisory and control system goes by the name of SCADA, acronym for supervisory control and data acquisition. These control centres, of which there may be one for the entire country, or several, scaled by order of importance and coordinated, are intended to ensure system security and may transmit instructions to generating stations to produce real or reactive power, order grid dispatching operations, change transformer taps or connect capacitor banks. Such instructions are based on system data, interpreted by operators on the grounds of their experience or with the support of sophisticated models that analyse operating conditions and determine line flows or bus voltages under various hypothetical system contingencies.

The control systems installed in production plants constitute the second level of operation. The two most important such systems are speed and voltage regulators.

Speed regulators maintain the instantaneous balance between generation and consumption in the system as a whole. The generating plant must respond immediately to any increase or decrease in demand. Similarly, the accidental tripping of a unit in operation at any given time (where nuclear power is involved, this may mean up to 1500 MW) induces an instantaneous imbalance between power generated and consumed that must be compensated for by immediately replacing the failed unit. When the power generated differs from the system load, any surplus power is stored or any shortage is drawn from the kinetic energy stored in rotating machines. Speeding up or slowing down these facilities changes the revolutions per minute in the AC generators or the frequency of the generated voltage wave. Such parameter changes automatically activate the respective steam-, water- or gas-driven valve to modify plant generation accordingly. This is called *primary regulation* or *load-frequency control.*

A power shortage caused by a power station failure, for instance, prompts a joint response across the entire inter-connected system, i.e., all the independently dispatched power

systems, synchronously connected to the power system where the shortage occurred, are involved. This arrangement prevents system frequency from falling further but is unable to re-establish it exactly to the nominal value. Nor are the predetermined values of power exchanges with neighbouring systems sustained, due to the flows required to maintain the frequency. A second control loop, known as *AGC or automatic generation control*, re-establishes frequency to the nominal value and the exchange flows to their initial levels. This constitutes what is known as *secondary regulation*, which is also usually automatic, and does not involve all generators, in particular none located in neighbouring systems. The extra generation required is redistributed among the stations chosen for this purpose according to pre-computed factors resulting from economic considerations. This also regenerates the primary reserve capacity, to ensure continued operation and prevent system standstill resulting from units reaching their capacity limit.

Lastly, *tertiary regulation* may also be implemented. At this level, in which supervision is not automatic, the control centre may change long-term dispatching instructions to enhance economic efficiency and restore the so-called secondary reserve capacity, in much the same way that secondary control restores the primary reserve capacity. Secondary and tertiary regulation form part of the higher control level referred to earlier, but they have been described here for greater clarity[28].

In a centralised environment, the economic aspects at this level are mainly taken into account by economic dispatch according to the variable costs of the scheduled units and recomputed every few minutes. The system operator, taking into account the technical and economic characteristics of the available plants, schedules the provision of operating reserves to maintain system security. No special payments are necessary to obtain these services from generators under a cost-of-service remuneration that covers their fixed and variable costs.

Power stations are equipped with a second control loop relating to system voltage. System voltage must be kept within certain allowable margins to ensure system security and guarantee that the power delivered is of reasonable quality. The voltage level of an electric power system is closely related to the balance of reactive power. High reactive consumption, either by live lines or inductive motors, tends to depress system voltages, whereas a supply of reactive power, from non-live lines or capacitor banks, for instance, tends to raise system voltages. For these reasons, power stations, which are able to produce or consume reactive power at will with their (synchronous) AC generators, are ideal candidates to monitor and correct dangerous voltage fluctuations. The voltage regulator measures voltages at generator terminals or selected points of the system, compares the measurement to a reference value and adjusts the AC generator excitation current accordingly, which controls the reactive power supplied or absorbed by the unit.

Power stations are naturally fitted with protection systems that prevent potential damage. The AC generator, pumps, turbines, and all other vital components are equipped with the respective measuring systems, tripping relays and alarms. The approach is as discussed above for substations: the protection relays must detect and locate faults, the

[28] The terminology that is used to classify frequency-related reserves varies much among power systems because of legacy reasons and also because of the diversity of generation mixes and reserve requirements.

automatic circuit-breakers clear them, and the disconnectors isolate the failure so that service can be re-established in the rest of the system while the fault is repaired. Protection relays must be sensitive enough to detect the fault, selective to minimise the impact of clearance, able to respond quickly for protection to be effective, and reliable, i.e., neither tripping facilities unnecessarily nor failing to act in critical situations. They must also be robust, since they operate under widely varying adverse circumstances, and able to operate independently and automatically, even in the absence of electricity.

Market-based decentralized approach

As under the traditional organisational approach, real-time operation is strongly influenced by security considerations and has a similar structure, although considerable effort is generally made to differentiate and clearly value the various types of so-called ancillary services provided by each agent in this respect.

Economic dispatch is covered by the outcome of the day-ahead market, backed by shorter-term markets (intra-day and balance markets). Deregulation has also caused several ancillary services to surface. These services are needed to ensure security, quality and efficiency of supply and were traditionally rendered by generation, but involve more than mere power production. Under competitive market conditions, ancillary services can be only provided if they are paid for or mandated. Whenever possible, the System Operator, as the entity responsible for ensuring system security, uses market mechanisms to competitively decide who provides what service and at what price. Substantial efforts have been made to define the ancillary services and the corresponding markets. Typical ancillary services include load-frequency regulation, i.e., secondary and tertiary regulation and load shedding, but also voltage control and even black-start capability (from blackouts). Primary load-frequency control is normally considered a basic mandatory service, at the disposal of the System Operator as a key element to guarantee system security.

In this competitive framework, companies must offer their services on the grounds of the costs incurred in their power stations to provide them, as well as of other considerations such as market opportunities.

5. ENVIRONMENTAL IMPACT

Environmental concerns have become a factor of equivalent weight as security and economic considerations in the planning and operation processes of the electric power industry. There is widespread belief that one of the major challenges facing humanity today is the design of a model for sustainable development, defined as development that meets the needs of the present without compromising the ability of future generations to meet their own needs. Besides such weighty issues as the enormous social and economic inequalities between peoples or the existence of a growth model that can hardly be extended to the entire world population, other issues directly related to electric power systems, such as the intense use of known energy resources and their adverse impact on the environment, also come under the umbrella of sustainable development. For these reasons, environmental impact is a factor of increasing importance that conditions the present operation and development of these systems and will indisputably have an even more pronounced effect on the industry in the future.

Generation is arguably the line of business in electric power systems that produces the greatest environmental impact, in particular with regard to thermal plant emissions and the production of moderately and highly radioactive waste. As far as combustion is concerned, coal- and oil-fired steam plants compete with the transport industry for first place in the emission of carbon dioxide (CO_2) associated with greenhouse gas-induced climate change, nitrous oxides (NO_x) and sulphur dioxide (SO_2), the former related to the formation of tropospheric ozone and both responsible for acid rain.

Other environmental effects of conventional steam power stations include the emission of particles and heavy metals, the generation of solid waste such as fly ash and slag, the heating of river, reservoir or sea water to meet the cooling needs of the steam cycle and, indirectly, the impact of mining. As no combustion is involved in the operation of nuclear power plants, they produce no CO_2 emissions and are not directly contributing to global warming[29]. Leaving aside the possibility of an accidental catastrophe, the inevitable accumulation of radioactive waste is, presently, an unsolved problem that affects coming generations so severely that nuclear power as it is known today cannot be regarded to be a sustainable source of energy.

In any event, even generation facilities that use renewable energy and are considered to be the most environmentally friendly technologies, have an adverse impact, in particular when the entire life cycle of the plants is contemplated. The most numerous of such facilities, namely hydroelectric power plants, which have existed ever since electric power was first industrialised, change the surroundings radically, flooding vast areas, altering rainfall, disturbing habitats or even transforming microclimates, not to mention the risk of accidents that can spell vast ecological and human disaster.

Other more recent technologies also have adverse consequences. Wind energy involves the disturbance of natural habitats and noise; solar energy, land occupancy and the pollution inherent in the manufacture of the components required for the cells, and more specifically the heavy metals present in their waste products; and biomass, the use of the land for this purpose and, potentially, an adverse CO_2 emissions life-cycle balance, depending on the biomass management approach. In fact, all electricity generation activities have one feature in common: visual impact due to land occupation, but the area involved and the (not necessarily proportional) extent of social rejection vary considerably with the technology and specific local conditions.

In a similar vein, the huge overhead lines that carry electric power across plains, mountain ranges, valleys and coasts and circle large cities have at least a visual impact on the environment, which is being taken more and more seriously. Less visible but indubitably present are the electromagnetic fields whose potential effects on people are still being evaluated. Such considerations have important consequences, since environmental permits and rights of way constitute strong constraints on the expansion of the transmission grid. As a result, the grid is operating more and more closely to its maximum capacity, occasioning new technical problems, for instance with respect to its

[29] For nuclear, as well as for any other technology, the entire life cycle must be considered, and not only the operation phase. Under this correct perspective no technology is free from emitting greenhouse gases or other environmental negative impacts, although significant differences exist among them.

dynamic behaviour, which logically have economic and reliability impacts. In some cases alternative solutions are available, albeit at a higher cost, such as running underground lines in densely populated areas.

The question, however, is not solely the establishment of the magnitude of the environmental impact of the electricity industry or of the awareness that minimising this impact generally entails increased system costs. The question, rather, is whether or not this impact should be considered when deciding how to best allocate society's scant resources. In a free market, the tool for resource allocation is product price, in this case, of the various power options. Nonetheless, the general opinion, of both the public at large and governmental authorities at the various levels, is that energy prices do not cover all the types of impact discussed above. This is what is known as a market failure or externality, defined as the consequences of production or consumption processes for other economic agents that are not fully accounted for by their costs.

The existence of such externalities, also called external costs, therefore leads to an improper resource distribution in the economy, preventing the market from suitable and efficient allocation of the resources on the basis of their price. Indeed, since account is not taken of these external costs, the price of energy is lower, and therefore consumption and environmental impact are higher than they would be if the true costs of resources were accounted for. The existence of externalities, if not taken into consideration, also leads to the choice of more highly polluting power technologies than if allocation were optimum. In order to correct this market failure and achieve optimum allocation, such costs must be internalised and built into the price in such a way that the economic agents can include them in their decision-making and ensure the best possible outcome for society as a whole. In the meantime, command-and-control type of regulatory measures can be adopted to create a more level playing field among more and less clean technologies.

Climate change.

CO2 accounts for about 76 percent of total greenhouse gas emissions. Methane, primarily from agriculture, contributes 16 percent of greenhouse gas emissions and nitrous oxide, mostly from industry and agriculture, contributes 6 percent to global emissions. All figures below are expressed in CO2-equivalents.

Energy is responsible for the majority of climate change-causing greenhouse gas emissions, mostly from the burning of fossil fuels.[30] 44% of total CO2 emissions come from the burning of fossil fuels in power plants to produce electricity and heat. Transport is responsible for 23%, industry for 18% and residential for 6%, mostly from burning fossil fuels for heating.

Africa, with 18% of the world population, is responsible for 3.1% of the total greenhouse emissions and for 3.6% of global CO2 emissions, of which power plants that generate

[30] See https://www.iea.org/world/emissions Note that numbers shown above refer to CO2 emissions from fuel combustion in the energy sector. They do not include other important sources of energy-related greenhouse gas emissions such as methane leaks from oil and gas operations, which are more difficult to measure.

electricity and heat are responsible for 56%, transport 22%, industry 10% and residential 6%.

Despite efforts to reduce these emissions, the trajectory of greenhouse emissions and the share of CO2 emissions globally remains far higher than what is needed to avoid the worst effects of climate change.

6. THE CONTRIBUTION OF REGULATION TO MEETING THE CHALLENGES OF THE POWER SECTOR IN AFRICAN COUNTRIES.

The path to a sustainable energy model in Africa – including universal access and climate change mitigation and adaptation, as well as the growing presence of decentralised energy resources in the midst of a much-needed industrialisation process – requires new approaches to policy, regulation, technology, innovation and skills to achieve this goal. Sound regulation stands out as an indispensable component of any strategy to guide African countries in designing and implementing this transition, as established in the Agenda 2063 for sustainable development on the continent.

The power sector in African countries should be the main driver of this transition, but its progress is being held back by regulatory barriers that could be overcome if good regulatory practices that already exist – elsewhere in the world, but in some cases also in Africa – could be adapted to the context of African countries, laying the groundwork for designing and implementing the necessary reforms. In most cases, the significant potential for change lies in getting the interactions between technology, economics and regulation right. A few examples stand out.

Electricity access.

"Affordable energy for all Africans is the immediate and absolute priority for the African energy sector.[31] Achieving universal electricity access requires a geospatial techno-economic plan to determine the least cost mix of electrification technologies – grid extemsion, minigrids and standalone systems – so that no consumer is left behind. Sustainable and scalable business models must be defined to determine the agents who will be responsible for the implementation of the plan. In addition, a viable financial plan is needed to attract the various kinds of investment that are most adequate to carry out the electrification plan, considered in an integrated way.

The electrification plan must be enabled by financially viable and performant distribution utilities, sustainable and scalable business models for off-grid electrification with minigrids and standalone systems, and a system of tariffs and subsidies compatible with the financial plan.

In addition, to supply the hundreds of millions of new customers and the industrialisation processes that most African countries need to develop their economies it will be needed the massive deployment of renewable generation supported by flexible technologies to cope with the variability of wind and solar, as well as a well-developed transmission

[31] IEA (2022) "2022 Africa Energy Outlook". https://www.iea.org/reports/africa-energy-outlook-2022

network making possible the complementarity of the diverse generation technologies and the effective and efficient integration of distributed energy resources (DERs) to go together with the traditional centralised supply system

Electricity distribution.

Most distribution companies – or the distribution arm of vertically integrated utilities – in sub-Saharan Africa are loss-making and underperforming. Many are unable to cover their operating costs, let alone their capital costs. However, regulatory instruments such as long-term concession contracts can transform these bankrupt utilities into financially viable companies with satisfactory performance. These regulatory approaches have been successful outside Africa and have been tried in some African countries, with mixed results. However, much has been learned from past experience and these regulatory approaches are ready to be applied, with the necessary adaptation to the context of each country.

Off-grid electrification.

Even if all distribution companies in sub-Saharan Africa were financially sound, it would not be wise to rely solely on extending their grids to provide electricity to the 650 million people without it, mostly in rural areas far from the existing grid, often in small and dispersed communities with limited economic resources. From a technical and economic perspective, the best approach to achieving universal access to electricity is to use three modes of electrification: grid extension, minigrids and standalone systems. Numerous studies indicate that each of these three electrification modes must be used to electrify about one-third of the remaining population without access. However, the regulatory and business models currently employed to deploy off-grid solutions – minigrids and standalone systems – are neither scalable nor sustainable and therefore unable to attract the massive investment required. Regulation can help kick-start the necessary mass deployment of mini-grids and off-grid solar systems by ensuring that business models are sustainable and scalable.

Regulation is also needed to incentivise last-mile electricity providers – on-grid and off-grid – to promote the human and economic development that access to electricity makes possible. This can be facilitated if the last-mile electricity providers also engage in microfinancing activities and sell efficient appliances for domestic, community and productive uses.

Investment and deployment of renewable generation.

Africa has immense potential for solar energy, but only about 1% of the world's installed PV generation capacity. Several African countries have announced ambitious decarbonisation and clean energy transition targets, but these commitments are wishful thinking unless accompanied by enabling regulatory frameworks to facilitate private sector investment. Regulation can increase the appetite for investment in renewable energy generation in Africa – both utility-scale and off-grid solutions – through a three-pronged approach. First, by removing barriers created by regulation itself, such as eliminating fossil fuel subsidies or streamlining complex permitting, licensing, grid connection and procurement processes. Second, through positive measures to accelerate the deployment of renewables, such as well-designed competitive auctions and contracts,

ensuring that adequate grid infrastructure is in place, or facilitating the participation of variable renewables in wholesale electricity trade. Finally, by avoiding counterproductive policies and regulations, such as adopting unsustainable off-grid business models, introducing ill-designed subsidies or banning all investment in fossil-fuelled generation, which may be transitorily necessary for industrialisation and to combine with variable renewable generation.

Although renewable (green) hydrogen is presently two to three times more expensive to produce than oil and gas[32] and now has a limited market and limited infrastructure, it is likely to further disrupt energy value chains in the coming decade.

The transmission network.

Africa needs massive investment in transmission, on a scale that far exceeds what can be built with public funds. However, private investment in transmission is virtually non-existent in Africa, while it is common around the world. A major factor contributing to the lack of private investment is the current regulatory regime, which in some countries either directly prohibits private investment for no good reason, or creates unnecessary financial risks that deter investors. Sound transmission regulation – as used elsewhere in the world – could help attract the private investment that is urgently needed to strengthen national grids and build the cross-border transmission links that are essential for electricity trading and the creation of the African Single Electricity Market (AfSEM).

Distributed energy resources.

Distributed generation – typically in the form of rooftop solar panels and diesel generators – and other devices – batteries, advanced meters, thermostats, electric vehicles and all kinds of smart appliances – commonly referred to as "distributed energy resources" or DERs – are increasingly being connected to the electricity grid at the customer level. Well-designed regulation can guide the deployment of socially beneficial DERs embedded in the main grid that meet the interests of individual owners – better reliability, lower costs, independence – while also being socially beneficial. Unfortunately, this is not currently the case, and the rapidly growing presence of DERs is largely taking place in the absence of regulation, or under regulation designed for a different type of electricity system.

Methods of remuneration of the distribution activity must be adapted to the presence of DERs and the availability of digital technologies. These methods, enhanced with incentive-based regulation, can be used to reduce losses and improve the reliability of supply.

Tariff design.

Tariff design is a key regulatory task, closely related to, but distinct from, the determination of the regulated remuneration of each of the activities involved in the supply of electricity to end users. Tariff design brings together most of the previous topics and the current approach needs to be rapidly reviewed in the light of the growing

[32] IRENA, https://www.irena.org/Energy-Transition/Technology/Hydrogen

presence of DERs. Regulated subsidies are the necessary consequence of policy decisions that accept a difference between the amount expected to be recovered through customer tariffs and the cost-reflective revenue requirement to cover the costs of all activities in the electricity supply chain. Tariff design is critical to the financial viability of electricity supply activities and has a high visibility and socio-political impact.

Regional power trade.

In Africa the capacity of interconnection between neighbouring countries is very low in general. This situation makes impossible to exploit economies of scale in the deployment of generation plants, and impedes the efficiency and reliability gains derived from coordinating the operation of the power system from a regional perspective.

Current rules for electricity trading need to evolve from the original physical bilateral contracts to more efficient and flexible arrangements that can draw on best international practices, including the allocation of access to limited cross-border transmission capacity.

In order to overcome these challenges, African countries collaborate by establishing power pools for electricity trade between neighbouring countries and to attract investment in generation plants and transmission lines with a regional perspective. Reaping the benefits of a power pool requires careful market design based on sound technical, economic, and institutional analysis of the systems as they exist today and will likely evolve in the future. An even more ambitious initiative contemplates the creation of an African Single Electricity Market (AfSEM). The specific regulatory and business model solutions to the challenges of regional integration in Africa also require an attentive consideration of political economy aspects at country, regional and continental level.

The future generation mix.

Regulation can also help to steer a country's generation mix in line with policy guidelines to meet the objectives of electrification, industrialisation and climate change mitigation. The interaction, complementarity and competition between electricity and gas at different levels need to be considered.

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