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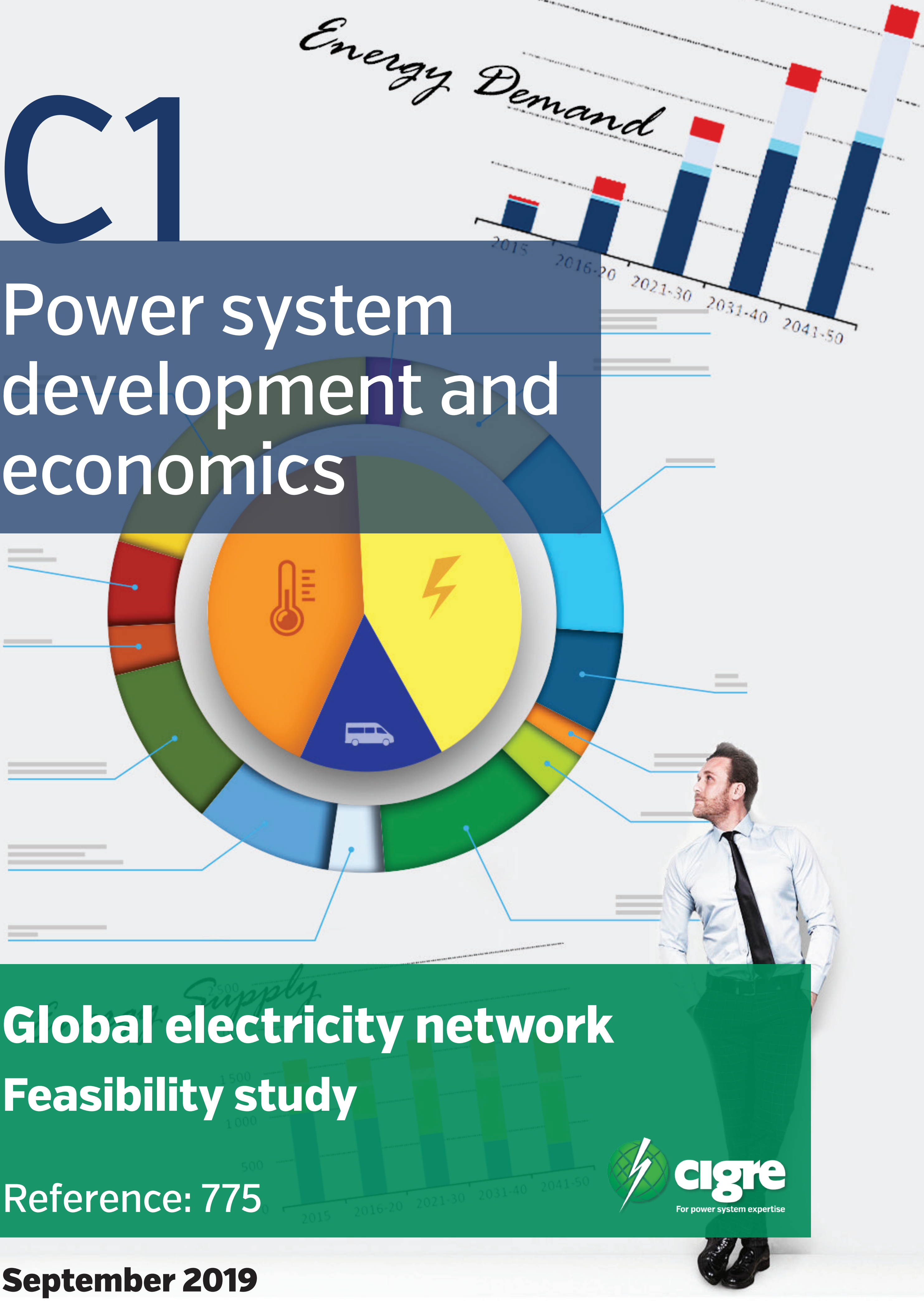
Power system development and economics



Global electricity network
Feasibility study

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Global electricity network
Feasibility study

WG C1.35

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Executive summary

Over the past decades, global electricity consumption has steadily increased, and this trend is expected to continue in the future, with consumption forecasted to grow from 22000 TWh in 2017 to 40000 TWh by 2050 [1]. Moreover, in 2016, over 65% of global electricity supply came from power plants burning fossil fuels [2]. As a result, if the same means of electricity production are maintained, carbon dioxide emissions are bound to increase substantially over the next decades. However, carbon dioxide has been recognized for its role as a potent greenhouse gas and primary driver of climate change [3]. In recent years, numerous states and organizations have therefore pledged to drastically curb their greenhouse gas emissions [4, 5]. In particular, the electricity and heat generation sector, which contributed approximately 42% of global greenhouse gas emissions in 2016 [6], has been identified as a key target of climate policies, many of which aim at replacing fossil fuel-based power generation technologies with renewable ones.

Even though an exhaustive list of potential benefits of renewable generation can be easily drawn, the vast majority of studies on the topic remain qualitative in nature and thus fail to quantitatively assess what it would take for the vision to materialize. The current study aims at filling this gap by offering a model-based, quantitative analysis of the costs and benefits the development of a global electricity network may entail. More precisely, an optimization-based framework is leveraged to identify the combination of generation and transmission assets minimizing the cost of satisfying electricity demands across pre-specified geographical regions under a set of technical constraints. In addition, the analysis is supported by a global assessment of variable renewable resource potential, as well as a careful examination of hourly-sampled electricity demand patterns across all regions considered in the model, which are both reported on in this report.

Overall, the results associated with the set of proposed case studies and senstivities suggest significant improvements of all key indicators (e.g., electricity cost, RES share, CO2 emission levels) compared to the base case assuming no interconnection capacities between regions. First, the existence of interconnection capacity between regions enables massive wind and solar PV deployments that replace a significant share of fossil-based generation capacity. This results into substantial increases of RES shares in the electricity mix and drastic reductions of CO2 emission levels. In terms of costs, the electricity mix shift towards V-RES technologies sharply decreases the operational expenses of fossil-based power plants, thus leading to overall system cost reductions from 54 to a minimum of 48 €/MWh.

One interesting outcome of all considered scenarios is represented by the large interconnection capacities built around Central Asia, a result supported by i) very good local wind resource, with an average capacity factor of 40%, ii) very good solar PV potential in adjacent regions, such as South Asia and the Middle East, and iii) its geographic role as transmission hub linking superior Variable-RES locations to massive demand centers (e.g., East and South Asia). Also, given the very long distances assumed between neighboring regions, DC is preferred as interconnection technology, while OHL AC lines are used only to connect regions whose connection points are located in close geographical proximity (e.g., Central and South Asia or East and South-East Asia).

To test results robustness, various sensitivity analyses are performed on selected parameters, with respect to the case study including intercontinental interconnections. Firstly, the impact of V-RES resource quality on the outcome of the model is investigated. In particular, altering wind capacity factor values in Central and East Asia, by a 10% decrease and a 3% increase, respectively, results in the replacement of more than 500 GW of wind turbines previously sited in Central Asia by additional V-RES capacities in neighboring regions, i.e. South, South-East and East Asia. In addition, the South-East to East Asian tie is reinforced in order to facilitate the integration of large shares of solar PV and wind generation, as well as the exchange between these two major demand centers. While an electricity cost increase of 1 €/MWh is observed, little change in RES share and CO_2 emissions level is recorded. Next, the impact of active power losses in interconnections and higher technology costs is studied. On the one hand, assuming zero losses across interconnections naturally leads to increased transmission capacities at similar costs, which in turn results in higher V-RES capacities deployed in regions gifted with superior resource quality. On the other hand, increasing transmission costs leads to lower interconnection capacities, with longer or submarine routes most affected, and corresponding increase in local V-RES as well as natural gas-fired generation capacity deployment. Because of the emergence of fossil fuel-based electricity production, the cost of electricity and CO_2 emissions soar, by 3 €/MWh and 100 Mt/year, respectively.

Moreover, the impact the availability of storage systems may have is also assessed using generic storage models. When daily storage is made available, PV deployments are favored over wind and gas-fired installed capacities, especially in regions with superior solar potential. As expected, the availability of storage leads to less interconnection capacity worldwide, yet the interconnections between South, South-East and East Asia are reinforced in order to enable the supply of massive amounts of solar PV to demand centers in the area. When seasonal storage is considered, wind and solar PV capacities increase, making gas-fired generation less attractive globally. Regardless of the sub-case considered, storage addition leads to decreased system costs and CO_2 emissions levels, due to increased RES shares.

In addition, the impact a change in the topology of the proposed network may have on results is also investigated. More specifically, the North America – UPS link, which is consistently built across scenarios and thus constitutes a key transmission corridor, is removed from the list of potential interconnections. In this setup, the Europe – North Atlantic – North America corridor, which did not emerge previously, appears. Owing to the high costs of laying submarine cables, the associated transmission capacity is relatively small. In addition, as the only direct link between the American continent and Eurasia is no longer an option, renewable-based energy flows into North America decrease significantly, which in turn leads to a noticeable increase in gas-fired power plant capacity deployed in this region.

Finally, the system design which would allow to supply the global electricity solely though V-RES and interconnections is probed. Clearly, the resulting system configuration features massively oversized wind, solar PV power plants and interconnection capacities, leading to enormous curtailment volumes (22000 TWh annually for the case deploying both wind and solar PV) and relatively high electricity prices (58 €/MWh, considering the same set-up).

Though sensitive to interconnection costs or transmission corridor choices, results consistently show that if a high carbon price can be agreed upon on a global level, the construction of interconnections allows to decrease both the cost of supplying global electricity demand and greenhouse gas emissions. Hence, as the number and size of interconnections keeps growing across the world, a global electricity grid may be envisaged as a valuable asset eventually connecting regions and continents to form a unique, cost-effective, low-carbon power system. This report essentially focussed on the techno-economic aspects of such a project. However, for the vision to materialize, challenges of a non-technical or economic nature will need to be overcome. In particular, in addition to issues pertaining to political will formation, social acceptance as well as long-term engagement and close cooperation between numerous international stakeholders, it is clear that designing proper legislation, regulatory frameworks and processes enabling or facilitating the construction, ownership and operation of such strategic infrastructure as well as the establishment of appropriate market structures will be key to the success of the project. In summary, the results of this study indicate that a global grid may constitute a cost-effective means of supplying global electricity demand and mitigating climate risk. This report therefore paves the way for further investigations, contributes to the debate on climate and energy policies in the context of the energy transition, and informs policy and decision-makers.

Contents

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1. Introduction

Over the past decades, global electricity consumption has steadily increased, and this trend is expected to continue in the future, with consumption forecasted to grow from 22000 TWh in 2017 to 40000 TWh by 2050 [1]. Moreover, in 2016, over 65% of global electricity supply came from power plants burning fossil fuels [2]. As a result, if the same means of electricity production are maintained, carbon dioxide emissions are bound to increase substantially over the next decades. However, carbon dioxide has been recognized for its role as a potent greenhouse gas and primary driver of climate change [3]. In recent years, numerous states and organizations have therefore pledged to drastically curb their greenhouse gas emissions [4, 5]. In particular, the electricity and heat generation sector, which contributed approximately 42% of global greenhouse gas emissions in 2016 [6], has been identified as a key target of climate policies, many of which aim at replacing fossil fuel-based power generation technologies with renewable ones.

Despite the envisioned benefits, notably in terms of carbon dioxide emissions reductions, the large-scale deployment of renewable-based generation technologies has brought about formidable challenges for power system operators and planners. More precisely, managing the intermittent and unpredictable production patterns of technologies exploiting abundantly-available renewable resources such as solar irradiance and wind has proven particularly challenging. Several solutions aiming at providing flexibility to the power system and reducing operating costs have been proposed, including the deployment or reinforcement of storage capacities [7], the tight integration of multiple energy carriers [8] or the development of interconnections between adjacent power systems [9, 10, 11]. The global grid concept, which has been recently proposed [12, 13] as a natural extension of the latter option and consists in integrating power systems on spatial scales ranging from country to intercontinental level.

The development of an intercontinental large-scale electricity transmission backbone, which is the topic of the present report, may unlock numerous benefits [12, 13]. On the one hand, it may enable harnessing renewable energy sources in vast quantities in resource-rich, isolated areas to feed energy-intensive demand centers with poor or limited local resource. On the other hand, tapping into renewable resources across continents and hemispheres would allow to exploit the inherent spatiotemporal complementarity between renewable production and load patterns, thereby smoothing out variability and easing system operation [14, 15]. In addition, potential socioeconomic benefits may include the development of regional power markets, strengthening of commercial exchanges between regions, the pooling of generation and reserve assets, and, owing to the sheer scale of such a project, the creation of jobs and economic activity.

Even though an exhaustive list of potential benefits can be easily drawn, the vast majority of studies on the topic remain qualitative in nature and thus fail to quantitatively assess what it would take for the vision to materialize, e.g. in economic terms, and whether it can actually deliver on its promise [16]. The current study aims at filling this gap by offering a model-based, quantitative analysis of the costs and benefits the development of a global electricity network may entail. More precisely, an optimization-based framework is leveraged to identify the combination of generation and transmission assets minimizing the cost of satisfying electricity demands across pre-specified geographical regions under a set of technical constraints. In addition, the analysis is supported by a global assessment of variable renewable resource potential, as well as a careful examination of hourly-sampled electricity demand patterns across all regions considered in the model, which are both reported on in this report.

This report is structured as follows. Chapter 2 provides a literature survey, which encompasses both academic studies and a comprehensive review of past, current, future and envisaged large-scale interconnection projects across the world. Chapter 3 introduces the methodology and the main assumptions applied. Chapter 4 details the scope of this work and the main data sources before the selection of regions and interconnection corridors is motivated. Chapter 5 reports on electricity generation and demand data acquisition and processing, before a detailed description of power grid technologies suitable for large-scale, long-haul electricity transmission is provided in Chapter 6. Next, generation and transmission costs used in the optimization process are summarized in Chapter 7. Chapter 8 details the optimization framework, its underlying assumptions and introduces the various case studies and sensitivity analyses, the results of which are presented in Chapter 9. Subsequently, Chapter 10 lists a series of potential non-technical challenges likely to arise in the development process of such a large-scale project, while the report is concluded and future work topics are proposed in Chapter 11.

2. Literature survey

The development of large-scale interconnections within or between regional electrical power systems, e.g. encompassing no more than a few neighboring countries or states, has become standard practice to strengthen network infrastructure as well as improve system reliability and security, whilst promoting commercial exchanges between subsystems [17, 18, 10, 19]. Building on this trend, the concept of a global grid has recently been proposed as a means of extending the benefits resulting from the interconnection of electrical power systems well beyond the regional scale and facilitating the integration of massive amounts of low-carbon electricity generated from renewable sources into power grids [12]. In order to further motivate the global grid concept, this chapter surveys some recent literature on large-scale interconnection development and the benefits it brings about. By considering systems of progressively-increasing geographical scope, this chapter provides a comprehensive account of past, current, future and envisaged large-scale interconnection development projects across the globe, whilst emphasizing how these developments can contribute to the emergence of a global electricity system.

2.1 Existing regional projects

In Europe, the development of electricity interconnections within and between countries has been actively pursued in recent years [11]. Such projects are envisioned as a way of achieving greater integration of European electricity markets and key enablers of European energy and climate policies [10, 20]. To further support those objectives, a regional body named ENTSO-E was established in 2009 and given appropriate legal mandates. This platform gathers 43 members operating transmission systems across 5 different synchronous areas and 36 different countries. The performance and weaknesses of the European electrical infrastructure are monitored and evaluated on a continuous basis, and future development plans addressing these shortcomings are published in ENTSO-E's Ten-Year Network Development Plan (TYNDP). Figure 2.1 summarizes European network expansions envisaged in a recent TYNDP [11].

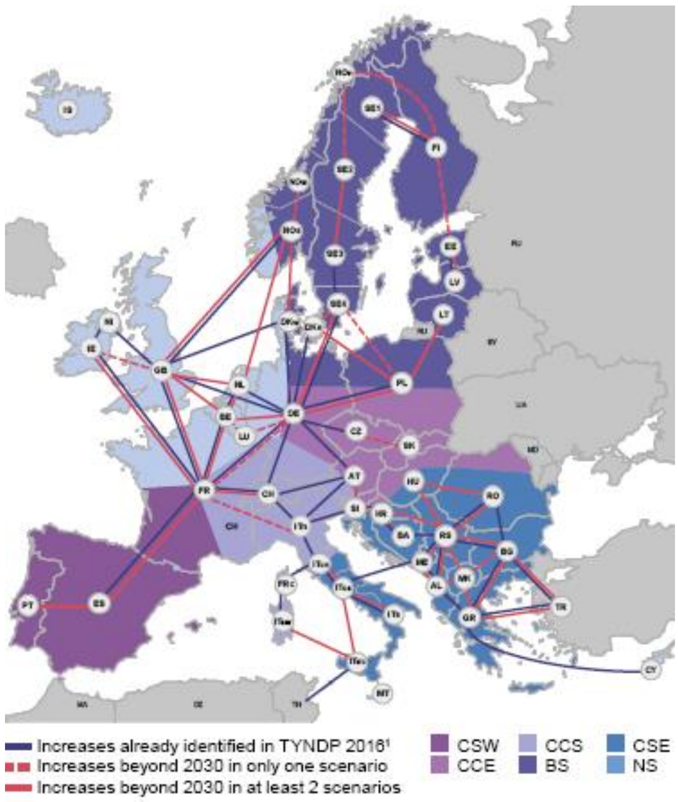


Figure 2-1. Proposed capacity increase in the European interconnected system by 2040 [11]

In the United States, as of late 2017, 66 different balancing authorities operate the transmission infrastructure in their respective balancing areas across three major synchronous zones spanning the contiguous United States and parts of Canada [21]. Some larger balancing authorities called Independent System Operators (ISO) resort to market-based processes rather than centralized generation scheduling such as unit commitment or economic dispatch to ensure both day-ahead and real-time adequacy. Within the synchronous areas, substantial interconnection capacity is already in operation across the U.S. - Canada border, enabling a tight coupling between electricity systems and power markets of the two countries and resulting in enhanced electric reliability and security as well as increased economic benefits [22]. Still, the need to strengthen and better integrate electricity grids both on a regional and a national scale to shore up power system resiliency, robustness and sustainability had been recognized as early as 2003 [23]. Projects to integrate the U.S. synchronous areas have been proposed [24], but, as of early 2019, their implementation appears to have stalled [25]. Nevertheless, recent studies reaffirmed that better regional and national electricity system integration would allow to exploit local variable renewable energy source (V-RES) potential more efficiently, and cost-effective upgrades to the U.S. electrical infrastructure serving those objectives have also been identified [26, 27]. Still on the North American continent, a project called the SIEPAC interconnection aims at unlocking benefits comparable to those discussed above by interconnecting several central American countries and further integrating their electricity systems [28, 9] The first interconnection was completed in 2014 [29], and funding for a second line was secured from the Inter-American Investment Corporation in late 2018 [30].

By contrast, as of early 2019, the African continent is split in five different power pools with very little interconnection capacity between them, and which essentially serve as platforms for regional electricity infrastructure planning and development [31]. Despite sustained integration efforts and growth in generation and transmission capacity within each power pool since 2010, the degrees of infrastructure and market integration effectively achieved vary widely between pools [32, 33]. Further developments in intra-pool and inter-pool interconnection capacity are envisaged and supported by the Programme for Infrastructure Development in Africa [34].

In the Arabian Peninsula, regional electricity system integration efforts have been underway since the formation of the Gulf Cooperation Council (GCC) in 1981 [35]. Following positive techno-economic feasibility studies, an Interconnection Authority was set up in 2001 under the aegis of the GCC and its member states, with the purpose of building an interconnector linking all countries in the region over the next few years as well as operating it. Operation started in 2009 and cross-border energy trading commenced in 2010. The next stages involve the launch of a spot market for electricity trading, expansion plans and connection to neighboring regions [36].

In Central Asia, most countries are linked by electricity transmission lines inherited from the Soviet era [37], even though the infrastructure was never designed to cater to the needs of each independent country. Efforts to remedy this and integrate electricity systems more efficiently have been made under the auspices of the Central Asia Regional Economic Cooperation Program [38, 39]. Further south, interconnecting the electricity systems of South Asian countries has been considered since at least 2004. It has been recognized that achieving an effective coupling of electricity infrastructure across the region would bring numerous benefits, but as of 2018, this prospect remained elusive [40]. It is worth mentioning analogous initiatives in South-East Asia [41, 42, 43], where varying degrees of infrastructure and market integration have been achieved.

In fact, well-integrated regional electricity systems can be viewed as essential building blocks conducive to the emergence of a global grid. Such regional clusters can either be progressively connected to each other or to remote areas boasting very high renewable resource potential, for instance via high-voltage direct current (HVDC) links [44], thereby expanding the scope of system integration beyond the regional scale and sharing the benefits that come along between regions. The next subsections focus on projects and studies exploring the potential of such interconnectors.

2.2 Beyond regional initiatives

Several large-scale interconnectors linking the European cluster to other regions have been considered in the literature. Among early studies on the topic, it is worth mentioning the Desertec initiative and MEDGRID which gathered numerous stakeholders, including research institutes, universities, consultancies, development agencies, NGOs, as well as partners from the industrial and finance sectors. The purpose of the project was to harness the V-RES potential of the sun-rich Middle East and North Africa (MENA) region and build the necessary power transmission infrastructure, notably relying on HVDC technology, to supply both MENA and European demand centers. [45, 46, 47, 48, 49, 50, 51]. In particular, comprehensive techno-economic analyses have highlighted the substantial economic benefits that may result from the large-scale deployment of renewables-based generation capacity across Europe and the MENA region along with the effective integration of both power systems, which is key to achieve deep decarbonisation objectives [52, 53, 54, 55]. Instead of focusing on high-quality solar or wind resources available in the MENA region, other studies have contemplated the prospect of harvesting renewable resources readily available in North-Western Europe, in the North Atlantic and in Greenland and transporting renewables-based power back to Europe. More precisely, such interconnections that would enable tapping into the very rich wind, geothermal or hydro electricity generation potential of these regions have been studied in [59, 60, 61, 62, 15] Rather than the transport of electricity from renewable resource-rich areas with little demand to the European cluster, the integration of the latter with other large clusters located in other regions of the world through large-scale interconnections has been investigated by the Joint Research Centre (JRC) of the European Commission [56, 57]. In [56], a market model is leveraged to assess the potential of a submarine HVDC connection from Europe to North America through Iceland and Greenland. By contrast, in [57], potential routes that would link China to Europe are evaluated, and the economic and regulatory aspects of such projects are briefly reviewed. In fact, studies comparable to those reviewed above and focusing on Asia rather than Europe have also been carried out. In particular, the prospect of producing renewable electricity in the remote, resource-rich Gobi Desert and Mongolia to supply North-East Asian load centers has been considered in [58]. Other studies have been conducted to assess whether high-quality wind and solar resources harvested in Australia could supply Asian load centers [59, 60]. Finally, the integration of clusters within Asia via large-scale interconnections, e.g. linking China, Eastern Russia, Japan and South Korea, has also been studied [61, 62, 63]. Finally, the power flows and exchanges that would occur in transmission systems within nine independent macro-regions spanning the globe and powered by an electricity mix incorporating extremely high shares of renewables are estimated in [62, 64].

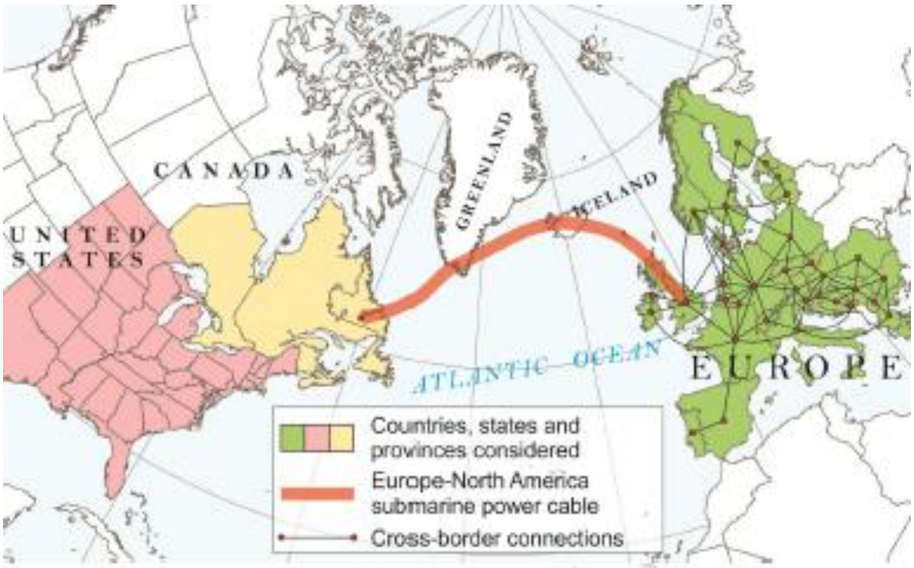


Figure 2-2 Submarine HVDC interconnection between Europe and the North American [61]

2.3 Towards a global grid set-up

The vast majority of studies reviewed so far in this chapter consider either a single interconnection corridor or interconnectors linking a small number of clusters and resource-rich areas. By contrast, several authors, including the members of this Working Group, have opted for a holistic approach to the study and assessment of the benefits and challenges of large-scale interconnections, by focusing on electricity transmission infrastructure spanning the globe and connecting all major clusters. An early contribution on the topic can be found in [12], which suggests the construction of large-scale intercontinental interconnectors to form a so-called global grid and facilitate the integration of massive amounts of V-RES power generation into power systems. Potential investment schemes and operational challenges are also discussed. A more detailed analysis of this project is given in a follow-up paper [65], where the economics of remote V-RES generation assets connected to major load centers via HVDC links are studied. A comprehensive treatment of the global grid concept is made in [13]. In particular, the global V-RES generation potential is evaluated (on a regional basis) and potential routes for long-haul transmission systems connecting load centers as well as resource-rich areas are proposed, as shown in Figure 2.3. The technical requirements and innovation needed for a successful implementation of this project are discussed, along with its far-reaching, global, socioeconomic and environmental implications. In complement to the aforementioned reference, a strategic framework for the implementation of this project is put forward in [66], where associated challenges and priorities are also analyzed and listed. Then, a white paper by the IEC [17] further expands on various aspects of the global energy interconnection concept. More precisely, it examines the maturity and market readiness of key enabling technologies and briefly discusses the economic feasibility of such a project from a high-level perspective. The paper also highlights that significant standardization efforts would be needed for the vision to materialize. In [67], the authors propose a quantitative analysis of intercontinental interconnectors as part of the greater global grid. The case study selected suggests a 5 GW tie between Europe and North America under a set of assumptions corresponding to a 2050 time horizon. The problem is formulated as an economic dispatch model seeking to minimize generation costs for a given power plant fleet to meet electricity demand under a set of techno-economic constraints. Finally, in [68], a set of United Nations scenarios about global population growth, primary energy supply and final energy consumption evolutions in the 21st century is used as a starting point for a study exploring the global power generation needs and generation capacity deployment patterns required to satisfy the evolving global electricity demand. Power flows which may occur between load and generation centers in such a context are then mapped, and interconnectors that would enable the aforementioned power exchanges are suggested.

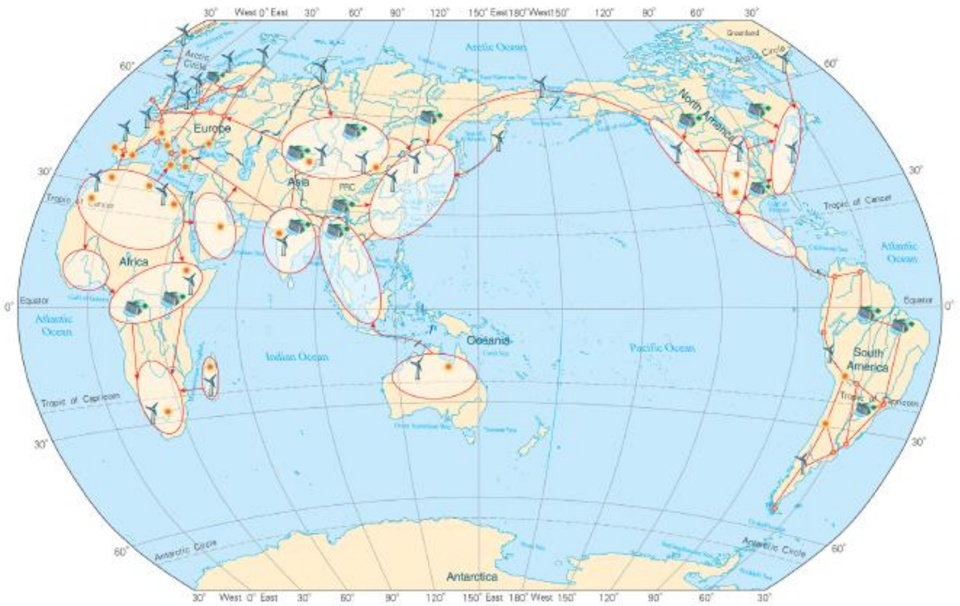


Figure 2-3. Schematic representation of the backbone electricity interconnection [13]

To conclude, the development of several projects reinforcing regional electricity transmission systems across the world is already underway or completed and well-documented (see Figure 2.4). Likewise, numerous studies have considered extensions to such projects as well as the prospect of connecting demand centers to each other or else to resource-rich areas via large-scale interconnectors. However, comparatively few papers adopt a holistic, global approach to the study of interconnection development and its potential for integrating renewable resources into electricity grids on a massive scale. In fact, to the best of the authors' knowledge, no study has so far provided a detailed quantitative analysis identifying the cost-optimal generation mix and intercontinental transmission capacities that would be needed in and between a set of predefined clusters and resource-rich areas spanning the globe in order to achieve a low-carbon, globally interconnected power system. This is precisely what this study aims to accomplish, focusing exclusively on a detailed techno-economic pre-feasibility analysis and leaving apart geopolitical and political will formation issues, as well as other non-technical and economic aspects the development of a global grid may entail.

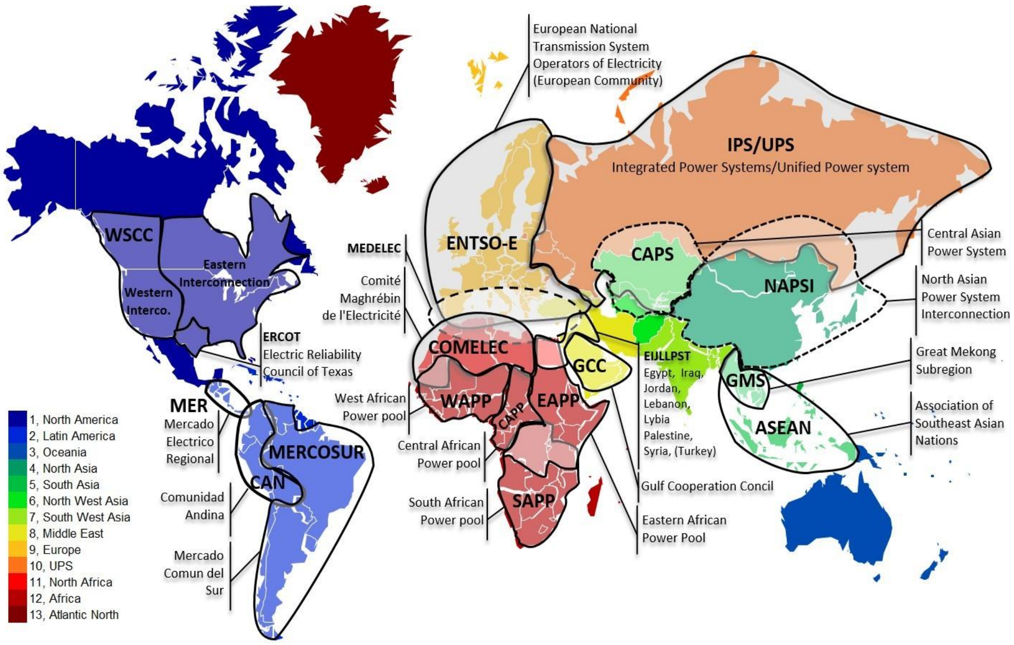


Figure 2-4. Identification of regional initiatives for the development of the grid at regional level

3. Methodology and main hypotheses

3.1 Scope and limitations

The central scope of this study, as defined in the terms of reference (ToR) of C1.35, is to carry out the first known feasibility study of a global electricity interconnection, by addressing the technical challenges, the potential benefits, the economic viability and environmental impact of such a project. More punctual information regarding the scope of this study and the associated building blocks can be found in the appendix B.

The present study is based on a set of assumptions encompassing predicted techno-economic developments on a global scale. In the upcoming sections, these assumptions (e.g., the evolution of the electricity demand and the construction of associated time series, the clustering of regions and the selection of corresponding transmission corridors, the estimation of renewable energy potential) will be introduced and discussed.

From the very beginning, a series of limitations inherent to this approach should be mentioned. First, as the current work focuses solely on the assessment of interconnectors and the associated inter-regional power flows, transmission systems within regions are not modelled, thus potential grid reinforcements that may be necessary to accommodate incoming flows are not considered. Second, the estimated variable renewable energy potential within each macro-region may differ from the empirical values associated with locations within it, but it rather corresponds to optimistic visions of solar PV and wind potentials in each region. Also, the process of demand time series projection to 2050 builds on the premise that there will be no changes in the daily/seasonal consumption patterns, an assumption that may not hold with the electrification of other demands (e.g., residential heating via heat pumps or transportation through electric vehicles).

3.2 Sources of data

The data collection process for this study targets information for different areas of the world from energy outlooks of international organizations (i.e., IEA, WEC), previous regional studies on the similar topics (e.g., e-Highway 2050 [10]), reanalysis datasets and internal surveys among the WG members. Collected data includes figures for energy supply and demand volumes, load and renewable generation demand time series, technology costs and technical constraints for generation and transmission equipment.

Taking into account these considerations, the WG C1.35 selected two major sources of techno-economic data: the International Energy Agency (IEA) and the World Energy Council (WEC). In this respect, the WEC published a relevant study in 2013 [69], which was updated in 2016 [1]. These two reports, with some amendments (explained in the following chapters), lay out the basic working assumptions in this feasibility study (e.g., electricity demand growth, electricity mix predictions). In addition to this source, the IEA report on projected costs of electricity generation [70] sets the main economic assumptions. Furthermore, the MERRA2 reanalysis dataset is used for V-RES potential estimation [71], while hourly electricity demand time series are obtained via an internal survey among WG members.

A set of inputs is required to describe any simulation instance. Such a collection of inputs (i.e., a scenario) is neither a prediction nor a forecast, but rather a possible vision of how worldwide electricity supply and demand patterns may evolve over the next decades.

In its 2013 report [69], the WEC developed two scenarios presenting a description of how some areas of the world could have evolved by 2050. The first of these two scenarios (the “Symphony” scenario) assumes sustained cooperation among global stakeholders in order to achieve environmental sustainability, while the second one (the “Jazz” scenario) relies more on decentralized solutions and market-based outcomes, while prioritizing energy access and affordability. These scenarios are designed to help a range of stakeholders address the energy trilemma: achieving environmental sustainability, energy security, and energy equity [69].

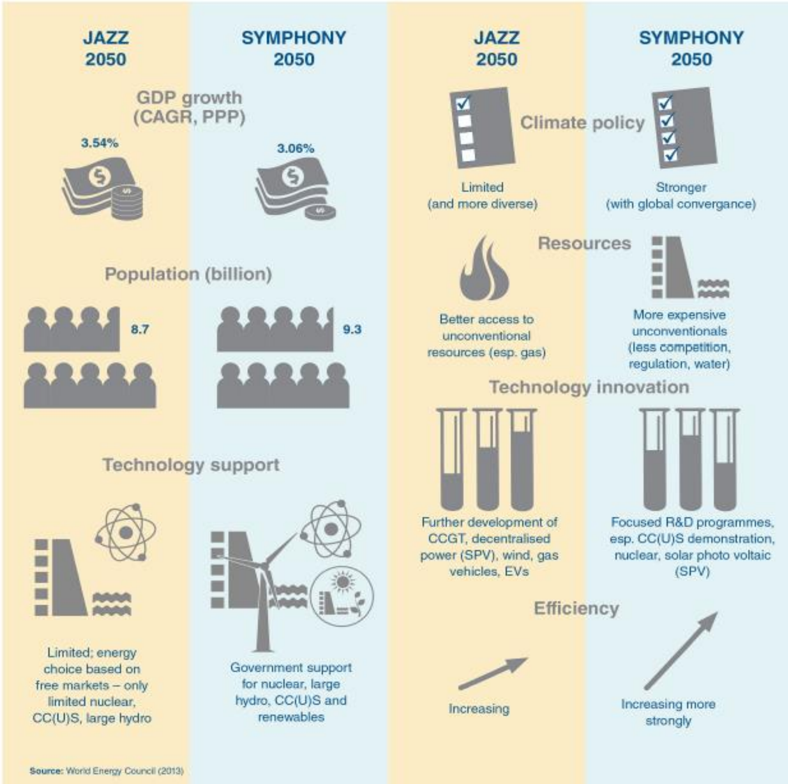


Figure 3-1: description of WEC scenarios – origin WEC study [62]

These two scenarios are built from a set of assumptions about socio-economic indicators, such as expected economic development, forecasts of population growth, environmental aspects or political decisions. In essence, the “Jazz” scenario considers moderate economic growth accompanied by population relocation from rural areas to urban centers, with private companies as main investors in power system assets, competitive markets as the main driver behind technological development and relaxed (electricity) trading frameworks between countries. The “Symphony” scenario considers weaker economic growth, the public sector (e.g., governments, municipalities, etc.) joining private companies as main investors in power system assets, markets being replaced by enhanced regulation as main driver in the technological selection process and stricter trading conditions between countries, still compensated by improved low-carbon frameworks promoted at country level. The comprehensive lists of characteristics of these two scenarios are detailed in the WEC report [69]. Regarding the electricity production, Figure 3.2 shows the origin of electricity production according to each technology.

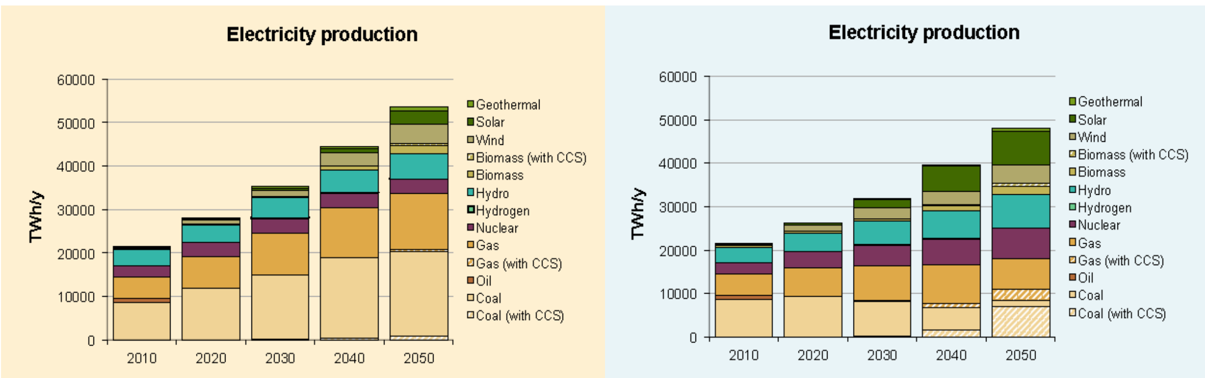


Figure 3-2: Electricity production of “Jazz” scenario (left), and of “Symphony” scenario (right), [75].

According to the “Jazz” scenario, the total electricity production in 2050 amounts to 53600 TWh, while the demand per capita reaches 5.4 MWh/year. Under the “Symphony” scenario, 47900 TWh are generated to supply a 4.6 MWh/year specific demand. The same study reports a total electricity production of 21500 TWh in 2010, with an associated demand per capita of 2.6 MWh/year. Under these assumptions regarding the electricity production by 2050, the associated installed capacities for electricity generation amount to 11700 GW according to the “Jazz” scenario, and 13900 GW according to the “Symphony” scenario, compared to 5100 GW in 2010. From an environmental impact standpoint, the two scenarios have a few differences. According to the "Symphony" scenario, a target of greenhouse gas (GHG) emissions limitation at 2 tons CO2 emissions per capita and year is reached by 2050, while such a target is not reached in the "Jazz" scenario. As a consequence, and considering the ToR of the present study, the "Symphony" scenario has been selected as a basis for the upcoming analyses.

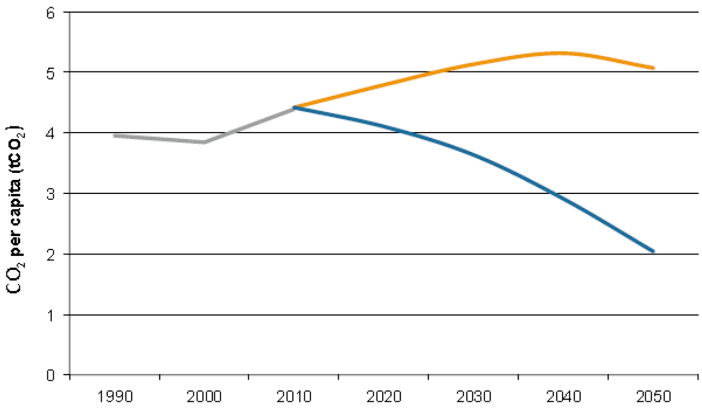


Figure 3-3: The specific CO2 (in tons per capita) emission targets, for the "Jazz" and "Symphony" scenarios [74].

In its 2016 follow-up report [1], the WEC updated the reference study taking into account electricity demand reductions, in line with updated forecasts. Thus, the "Symphony" scenario of the WEC was eventually replaced by the "Unfinished Symphony" (which assumes 40000 TWh generated electricity are enough to cover the global electricity demand by 2050) as the reference scenario for the C1.35 feasibility study.

3.3 Region selection

In the WEC reports, a model of the world divided into 8 regions is used.

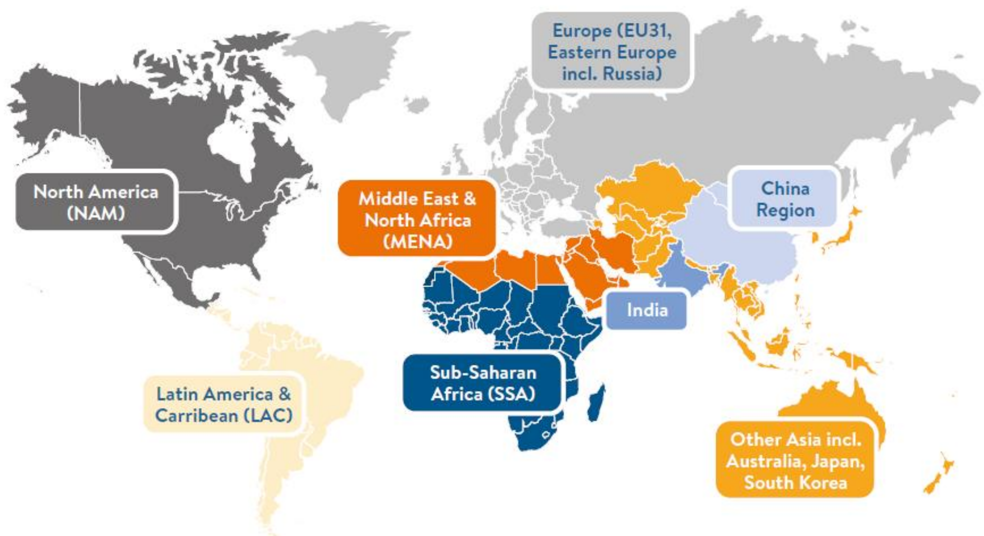


Figure 3-4: The 8 world regions selected by the WEC studies [74].

These regions, as shown in Figure 3-4, served as a basis for the regional clustering used in the present work. However, a number of modifications in the delineation of these regions was introduced by the WG C1.35 in order to better address the scope of this taskforce, bearing in mind its particular focus on interconnecting different land masses. More precisely, the region corresponding (in Figure 3-4) to Greenland, Europe, Turkey, and Russia, has been split in this study as follows: Greenland and Iceland form a single separate region, with characteristically high wind potential. Most of Europe has been assigned to a single region, while Turkey is included in the Middle East region. Furthermore, Belarus, Ukraine and Russia form a separate region. These modifications yield a thirteen-region model, whose nodes are positioned by taking into consideration the location of potential main substations belonging to existing transmission structures in each region considered. Otherwise, nodes are roughly located at the barycenter of the economic activity of each dedicated zone. Figure 3-5 illustrates the final regions and nodes used in the present study.

Figure 3-5: The thirteen regions as selected by the C1.35 workgroup.

3.4 Interconnections selection

The present feasibility study has limited the grid architecture to only one electrical node per region/continent. This coarse granularity is enough to provide a first quantitative assessment of prospective interconnection capacities and inter-regional power flows. Priority is given to the identification of major electric transmission corridors, including (i) the development of non-existent interconnectors and (ii) large capacity reinforcements (higher than 2 GW) for already existent connections. Other required reinforcements are disregarded. Although in the present feasibility study an interconnection between two regions is represented by only one corridor, such a corridor must be understood as several lines connecting the two regions. Hence, the capacity of any single corridor between two regions corresponds to the sum of the capacities of all lines connecting these two regions.

The technologies considered in this study include HVAC/HVDC overhead lines (OHL) as well as HVDC submarine cables (SC). Moreover, only a selection of interconnections between the different nodes have been analyzed by the C1.35 group, considering, for each connection, the most appropriate technologies. Finally, to limit the number of simulation cases, 20 interconnections have been selected (see Figure 3-6). The interconnections selected use preferential paths, accounting for the topography, the current grid, and the RES potential. A specific section of this report's appendix is dedicated to providing details regarding each of these 20 interconnections.

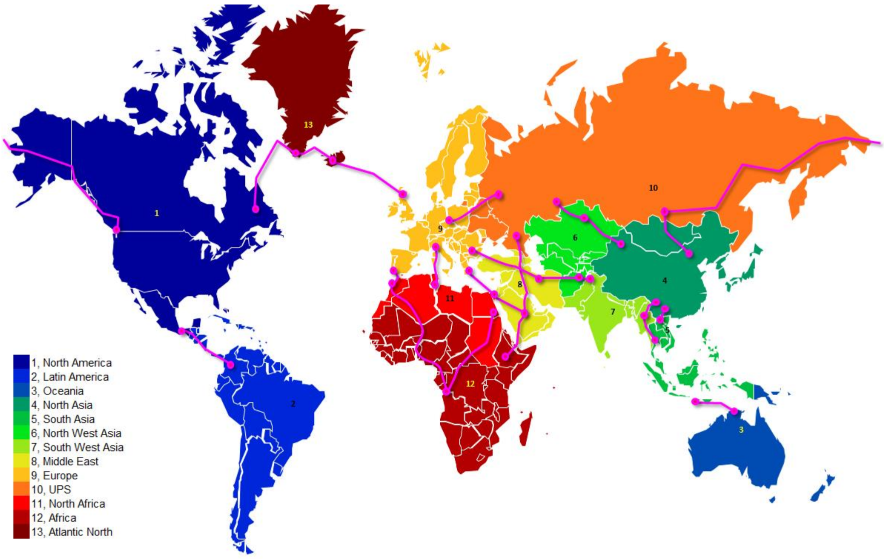


Figure 3-6: The 20 interconnections selected for the Global Grid assessment

4. Data collection and analysis

4.1 Conventional electricity generation

The amount of electricity generation per technology, as provided in the "Unfinished Symphony" scenario of WEC [1], is detailed in Table 4-1.

Table 4-1: Global electricity generation per technology [74].

	WEC 2013		WEC 2016			
Electricity fuel source (TWh)	2010 (TWh)	% source 2010	2014 (TWh)	% source 2014	2050 unfinished symphony (TWh)	% source 2050
Hydro	3500	16%	3895	16%	6448	16%
Wind (& other)	500	2%	732	3%	7524	19%
Solar	100	0%	198	1%	5802	15%
Geothermal	50	0%	78	0%	735	2%
Biomass	100	0%	493	2%	2227	6%
coal	8650	40%	9697	41%	1528	4%
oil	1000	5%	1033	4%	133	0%
nuclear	2800	13%	2535	11%	6546	16%
gas	4800	22%	5155	22%	8900	22%
total	**21500**	100%	**23816**	100%	**39843**	100%

The "Unfinished Symphony" scenario assumes the large-scale deployment of renewable-based power generation capacities. The share of these technologies is projected to reach 58% of the total electricity production by 2050, compared to 18% in 2010, mainly due to the sustained deployment of technologies harnessing wind (19%) and solar (15%) resources. Regarding conventional energy sources, the amount of electricity generated from nuclear and gas-fired technologies is estimated to double from 2014 to 2050, according to the "Unfinished Symphony" scenario. However, the share of conventional generation is expected to halve between 2014 and 2050 (42% compared to 78% in 2014).

As detailed in Chapter 7, in the model, the capacities of some technologies, namely wind, solar PV and gas-fired power plants, are optimally-sized whereas the capacities of all remaining technologies, that is, nuclear, coal, hydro and biomass, are kept fixed. Moreover, some pre-existing capacities are also assumed for wind, solar PV and natural gas-fired power plants, such that the total capacity for those technologies is obtained as the sum of pre-existing and optimised capacity values. As a result, installed (initial) capacities are needed for all technologies and serve as inputs to the model.

The "Unfinished Symphony" scenario [1], proposing an annual electricity generation of 39850 TWh, also suggests the distribution of this amount between different technologies (e.g., coal with CCS, nuclear, hydro, biomass, gas, wind, solar PV, etc.). However, it does not include explicit information about installed capacities of generation technologies on a regional basis. Therefore, the following procedure was adopted to derive the required inputs:

- The regional distribution is done using the regional shares of electricity generation proposed in the "Symphony" scenario [69];
- Since eight regions are used in [69, 1] and this study relies on a thirteen-region model, further processing of regional data is required. In particular, when a WEC region corresponds to multiple C1.35 regions (e.g., the MENA region employed in [69] is split into the Middle East and North Africa regions in this study), the projected production volume for the region is distributed among sub-regions (the Middle East and North Africa) as a function of the projected annual electricity demand per sub-region, which is computed from ENERDATA consumption figures. In other words, if a sub-region represents 30% of the regional annual electricity demand, 30% of the projected production volume will be assigned to it. In the case at hand, 80% of the initial generation is attributed to the Middle East, while the remainder is assigned to North Africa;
- For each region, the monotonic residual load curve (i.e., demand minus solar PV, wind, hydro generation – orange curve in Figure 4-1) is calculated;
- For each region, the installed capacity of each imposed technology is obtained by computing the height of the slice underneath the residual load curve having a surface area equal to the total generation reported for this technology in [69, 1], as illustrated in Figure 4-1 for nuclear power plants capacity in Region 1 – North America.

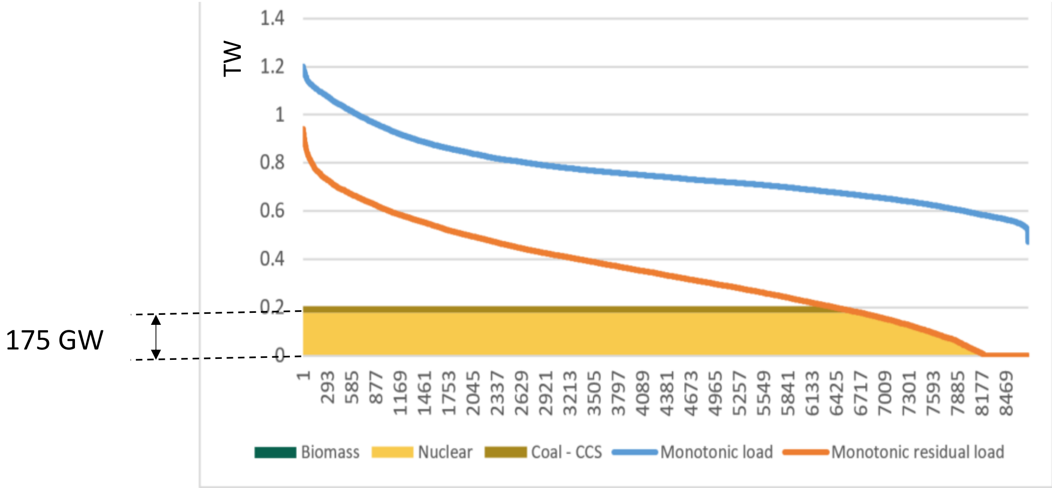


Figure 4-1. Region 1 - North America monotonic load in 2050.

Eventually, this procedure leads to over 3100 GW of non-sizeable, conventional electricity generation technologies. A large share of this amount corresponds to hydro and nuclear power plants, with 1826 and 889 GW installed, respectively. Regional information on this topic can be observed in Table 4-2.

Table 4-2. Installed capacities of conventional technologies per region.

GW	1 North America	2 Latin America	3 Oceania	4 North-East Asia	5 South-East Asia	6 Central Asia	7 South Asia	8 Middle East	9 Europe	10 UPS	11 North Africa	12 Africa	13 North Atlantic	**Total**
Hydro	295	268	45	420	78	21	127	5	300	166	2	99	0	**1 826**
Biomass	3	74	3	17	7	3	27	25	50	23	6	32	0	**269**
Nuclear	175	17	8	318	15	5	45	30	180	80	8	8	0	**889**
Coal CCS	28	3	4	32	8	2	20	3	30	13	1	7	0	**152**

4.2 Renewable energy sources potential

4.2.1 Sources and methodology

Later in Chapter 7, variable renewable energy generation (e.g., wind and solar PV) is a free variable in the proposed model, in which the optimization tool selects technologies (e.g., V-RES generation, natural gas-fired power plants, transmission capacity) that allow to serve the electricity demand at minimum system cost, while accounting for a set of technical constraints, as well as for investment and operational technology costs. In this context, accurately estimating the potential (i.e., the maximum amount of electricity which may be produced at any given location and for a unit capacity of a technology of choice) of weather-driven variable renewable energy resources (V-RES) is critical for delivering meaningful results.

In this study, the potential of V-RES is assessed from climatological data sampled at high spatial and temporal resolutions. Such features are defining characteristics of meteorological reanalysis datasets, in which results from a numerical model emulating the dynamics of global weather systems are calibrated by a set of historical observations (from satellites, weather stations or other measurement devices) in both space and time. The physical variables stored in such datasets are available over structured grids with fine spatial resolutions (e.g. less than one-degree longitude/latitude) and usually cover several decades. A well-known instance of such data sources is the MERRA-2 database, which is at the core of the proposed methodology for estimating V-RES potential. Developed and maintained by the Global Modelling and Assimilation Office (GMAO) of NASA, MERRA-2 provides modelled climatological data at a 0.5°x0.625° (latitude x longitude) spatial resolution, starting from 1980 [71]. For the purpose of this work, various reanalysis database variables representing physical quantities such as wind speed, air density, pressure, temperature at certain altitudes or solar insolation are processed to obtain capacity factor time series (as detailed in the upcoming section) quantifying the V-RES potential at each grid point.

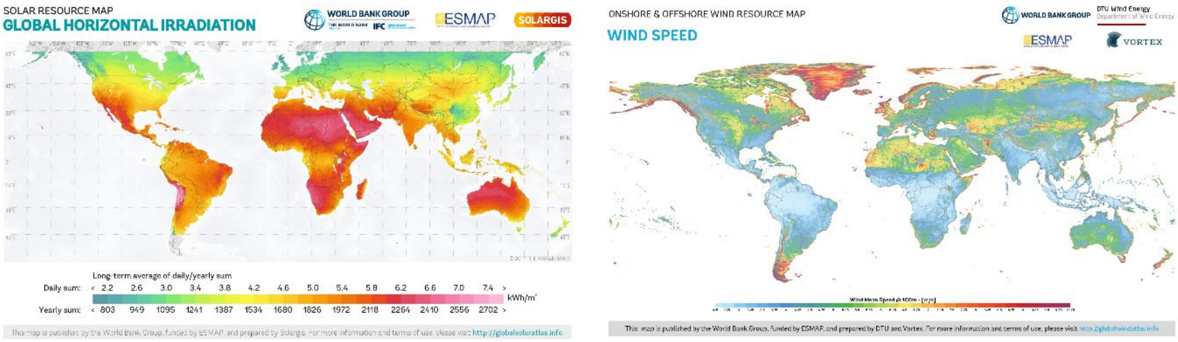


Figure 4-2 Global Atlas – left, Global Wind Atlas – right, used in the screening process of interest areas. Source: [72, 73].

The availability of data at high spatial and temporal resolutions is one of the key advantages of reanalysis databases in power system studies. Nevertheless, evaluating the V-RES potential of a very large number of locations spanning the entire globe over several decades rapidly proves impractical due to the massive size of the underlying data.[1] Therefore, the estimation of the V-RES capacity factors within the thirteen regions of interest is done based on a set of simplifying assumptions. The first assumption relates to the spatial boundaries of the assessed areas. Within each region of interest, an area defined as a rectangle completely enclosed in the region is selected for further analysis through visual inspection of publicly available resource atlases (see Figure 4-2) [72, 73]. The size of these areas was established such that every region is represented by at least one hundred nodes, as displayed on the geodesic map of MERRA-2. Figure 4-3 displays the geographical locations of the areas used in the estimation of the V-RES potential. The second assumption concerns the time horizon selected for the data retrieval. In this respect, the last three complete years (i.e., 2015-2017) were selected. Finally, an average of all locations within a region is used as V-RES input to the optimization tool.

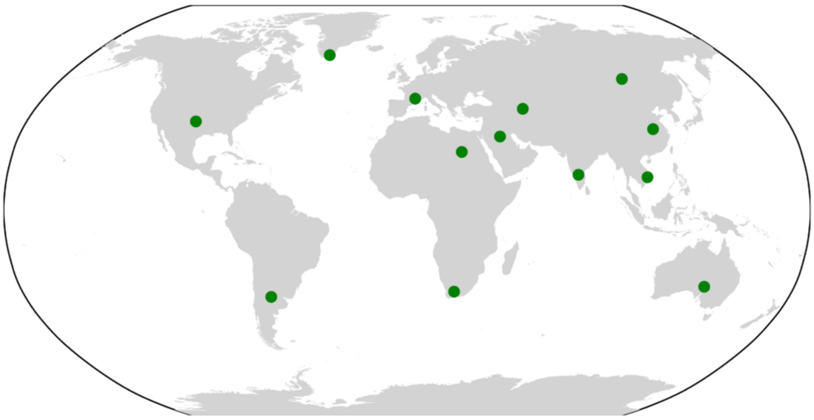


Figure 4-3 Selected areas for variable RES assessment within the regions of interest.

4.2.2 Results

Solar PV generation potential

The proposed reanalysis database (MERRA-2) provides incident solar radiation data at the surface and at the top of the atmosphere. Still, the electrical output of a PV module is determined based on global radiation components, therefore a data preprocessing stage was required for determining these components. Following the approach proposed in [74], direct, indirect and reflected fractions of solar radiation were computed from characteristic solar times and angles. In addition to that, the estimation of solar PV capacity factors depends on the choice of a given PV module technology, the technical specifications of which (e.g. nominal cell operating temperature, reference temperature, module efficiency at operating temperature, rated power of the module) directly impact the estimated potential.

[1]The challenge here is not only related to the CPU time required to process data, but also to the data download process itself. This results in a time-consuming process that is expected to provide marginal added value to the final outcome, when compared to the proposed simplified approach.

For the sake of accuracy and robustness, a state-of-the-art utility-scale PV module technology has been considered as reference [75].

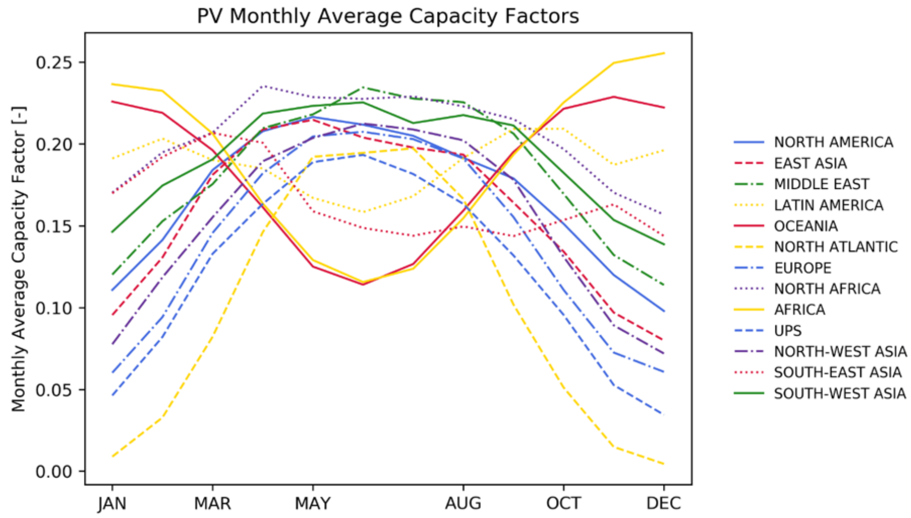


Figure 4-4 Monthly average solar PV capacity factors over a full year for the considered regions.

The results of this processing step are displayed in Figure 4-4 and Figure 4-5. The former shows the computed monthly average capacity factors over an entire year, for all thirteen regions considered. Firstly, in this plot, one can see the different seasonal patterns of PV production for locations situated in opposite latitudinal hemispheres. In particular, monthly-average PV capacity factors in Oceania and Africa (in the Southern Hemisphere) reach their maximum values in the first and last months of the calendar year. A similar pattern, though less obvious, can be observed for Latin America and even for South-East Asia. By contrast, in the Northern Hemisphere, one can observe year-round high-quality solar PV potential in North Africa, the Middle East and South-West Asia, while current major load centers (e.g., East Asia, North America or Europe) benefit from slightly poorer solar conditions throughout the year.

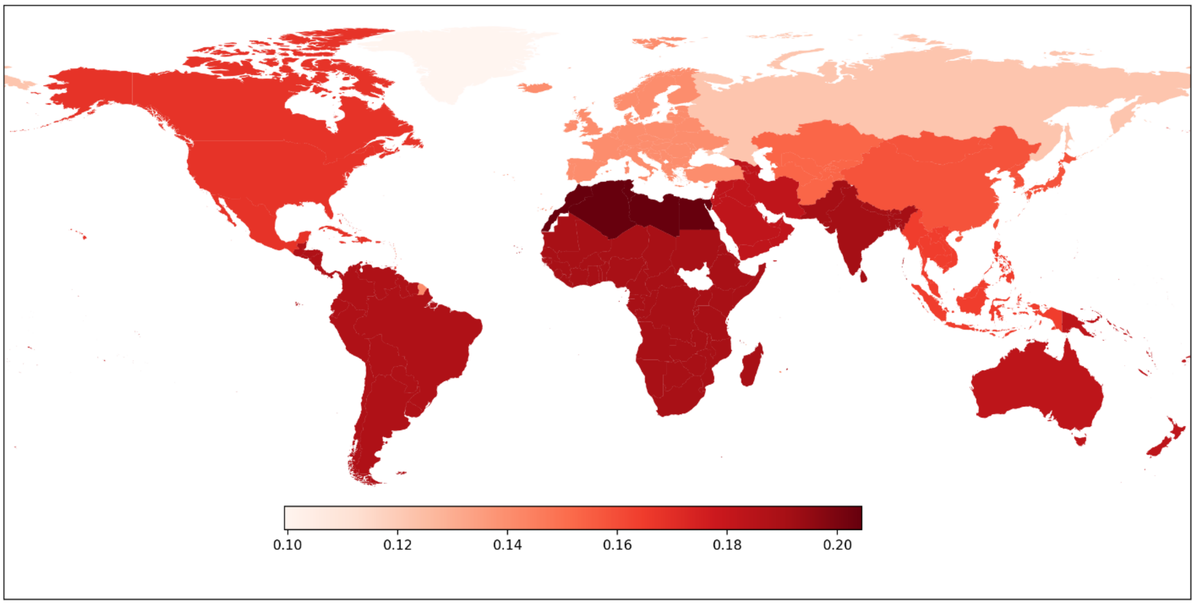


Figure 4-5 Choropleth map of average solar PV capacity factors over the considered regions.

The plot in Figure 4-5 displays the average (over the entire time period studied) solar PV capacity factors across the regions considered (comprising several countries). First, this plot confirms the observations resulting from the analysis of the previous figure. Indeed, the regions with the strongest overall solar PV potentials are North Africa, the Middle East and South-West Asia. Up next, Southern Hemisphere regions display very good solar resource, with average capacity factors above 18% over the entire simulated time frame. As one goes north, average capacity factors decrease rapidly to a 9% capacity factor value recorded in the North Atlantic region. It is worth mentioning that as a result of the selection method introduced in Section 4.2.1, a fairly high solar PV capacity factor value is assigned to the (entire) North/South American regions (even across the northern-/southernmost areas), providing a relatively optimistic account of resource potential in those regions.

Wind generation potential

For this study, wind speed data obtained from the aforementioned reanalysis database consists in the magnitudes of wind velocities at heights of 10 and 50 meters above ground, respectively. Hence, wind speed values at those heights must be extrapolated to obtain time series of wind speed values at wind turbine hub height (4.2 MW Enercon E126). This extrapolation is performed via a power law profile [76]. In addition, air temperature is adjusted to the hub height assuming a linear temperature gradient, while air density is calibrated by means of the ideal gas law [77]. In order to estimate the wind generation potential (i.e., the associated capacity factor time series) at all desired locations, the actual power output of the selected wind energy converter is estimated by mapping the constructed wind speed time series to power output levels obtained from the power curve of the turbine (as provided by the producer) [77].

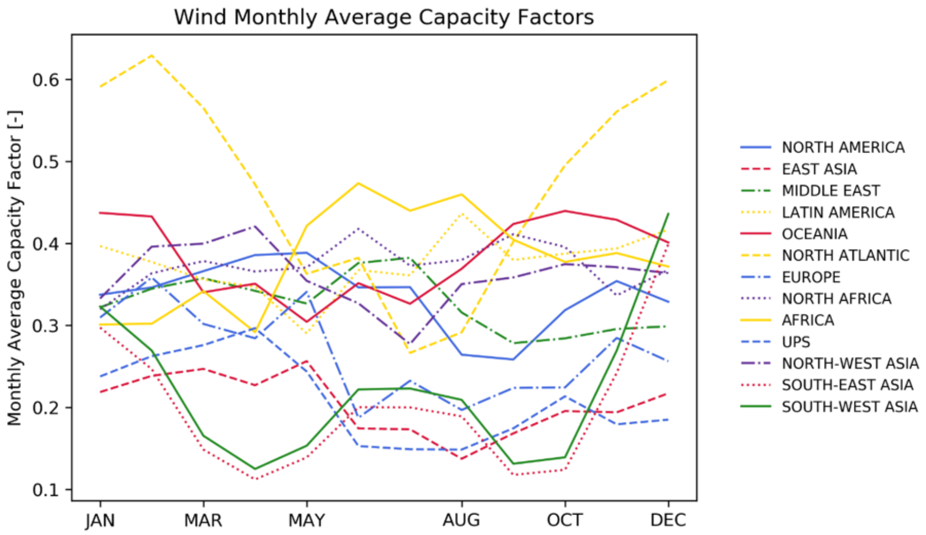


Figure 4-6 Monthly average wind capacity factors over a full year for the considered regions.

The wind generation potential across all considered regions can be observed in Figure 4-6 and Figure 4-7. The former shows the monthly average wind capacity factor values over a full year, which display increased intra-seasonal variability compared to solar PV patterns observed in the same regions in Figure 4-4. The North Atlantic region is by far the most productive in terms of wind generation, especially so in the winter months during which the monthly average capacity factor values in this area reach 60%. Furthermore, Oceania and Africa show strong and uncorrelated wind generation potential on a seasonal basis. North America also displays good resource quality anytime except in autumn, while at monthly time resolution North Africa is characterized by a quasi-constant wind generation profile across the year. On the other hand, modelled wind generation potential in most Asian regions (East, South-East, South-West Asia and UPS) is low, especially during seasons other than winter.

The following plot (Figure 4-7) shows a choropleth map of average wind capacity factors over the entire time frame considered and for all studied regions. As shown in the previous figure, the North Atlantic region possesses the highest wind generation potential. In addition, very good wind generation potential (over 35% average capacity factor) is displayed in Latin America, Africa, North-West Asia and Oceania. On the other hand, fairly poor wind resource is found in the vicinity of major demand centers (e.g., East, South-East and South-West Asia), where average capacity factors are close to 20%.

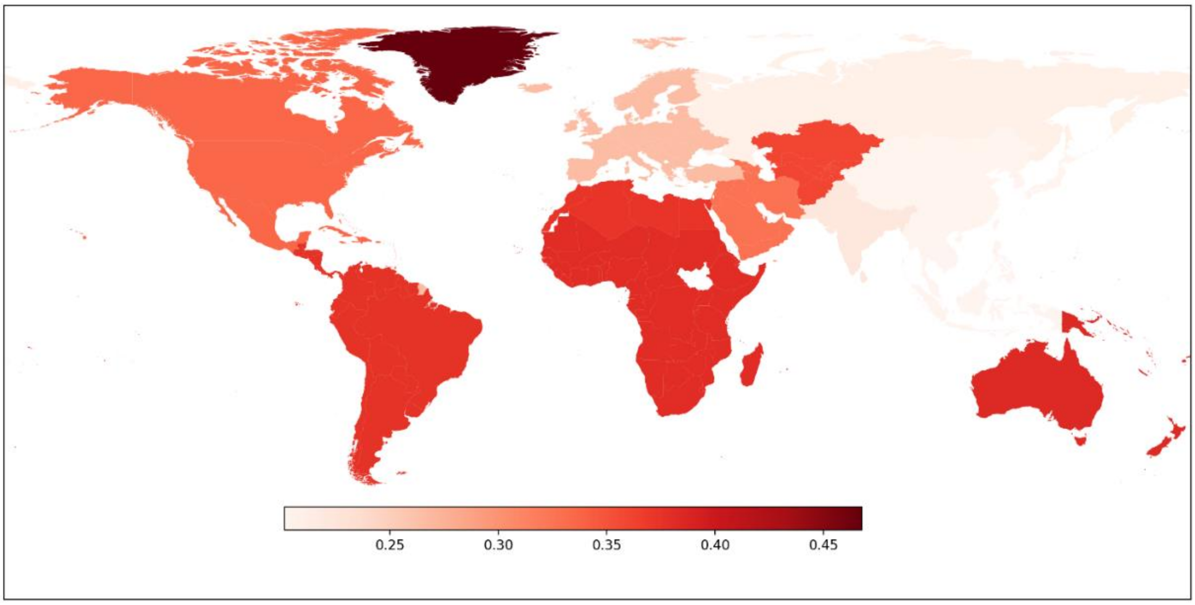


Figure 4-7 Choropleth map of average wind capacity factors over the considered regions.

Figure 4-8 summarizes yearly average capacity factor values for both V-RES technologies (i.e., wind and solar PV) for all thirteen regions considered.

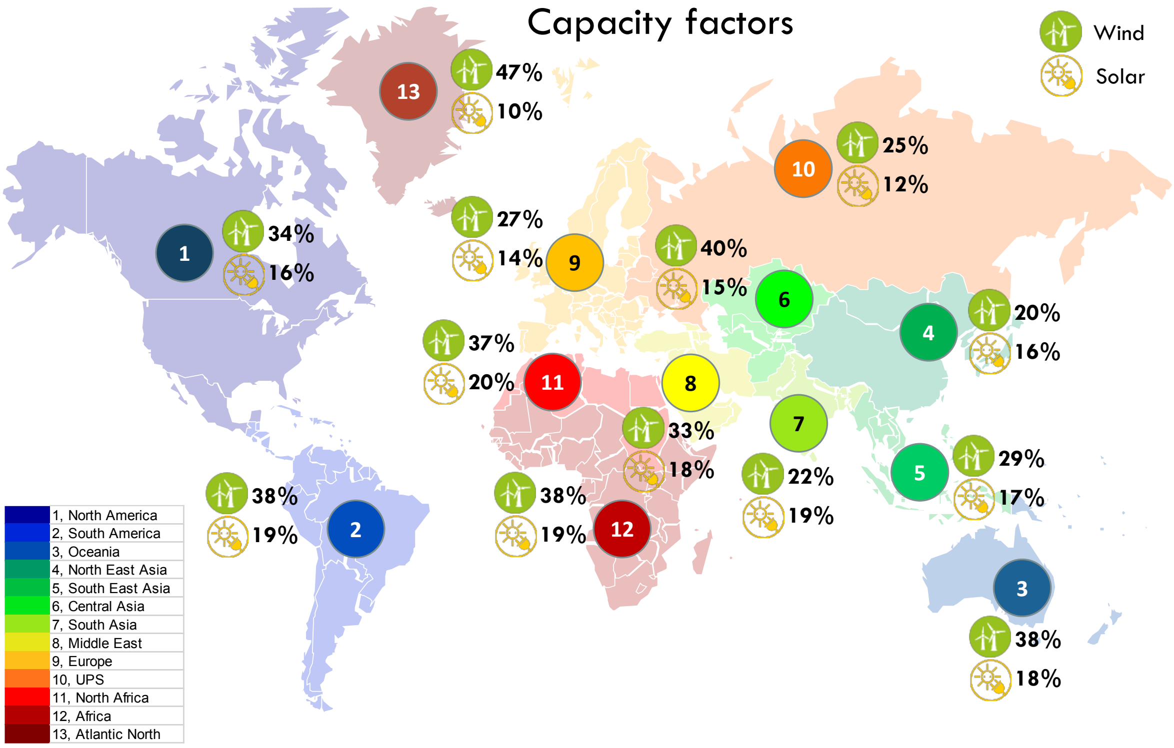


Figure 4-8. Capacity factors of variable renewable generation technologies per region.

4.3 Electricity demand

The WEC studies provide data for generation, installed capacities and overall electricity demand for each region. However, they do not provide electricity demand profiles (e.g., at hourly resolution), which are required for computing simplified power flows across the interconnections. Thus, additional input data was required.

An internal survey within the working group was conducted in order to acquire the missing piece of information, i.e. the hourly-sampled electricity demand profiles for one complete year, at country/regional level. Subsequently, the load curve of every region was obtained by aggregating the profiles (when available) of all countries belonging to that region. All required demand curves were not available, but around 90% of the total worldwide electricity demand of 2016 was covered. For example, Figure 4-9 shows the typical daily load curve of Region 9 - Europe 1.

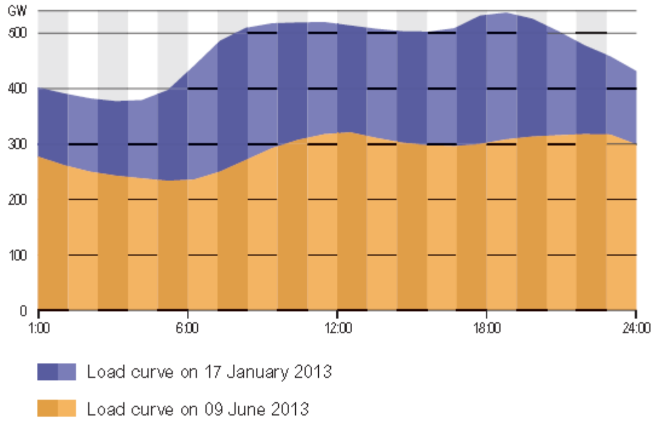


Figure 4-9: The daily load pattern in Europe, winter & summer 2013. Source [83].

Additional assumptions are required to estimate hourly demand profiles for the target year of the study (i.e., 2050). Concretely, the 2050 load curves are derived from the available 2016 data via homothetic transformations, with a scaling factor for each region given by the ratio between the electricity demand projected in 2050 [69] and the annual load in 2016. This transformation method was preferred over the translation method after discussions within the WG. As for the shape of the future hourly profiles, it is assumed that behavioral changes in the use of electricity (e.g., integration of electric vehicles or heat pumps) will cancel each other out, thus leading to similar patterns as the ones we currently observe, yet with a scaling effect due to the increased overall demand. Plots in Figure 4.10 reveal the results of the homothetic transformation proposed above.

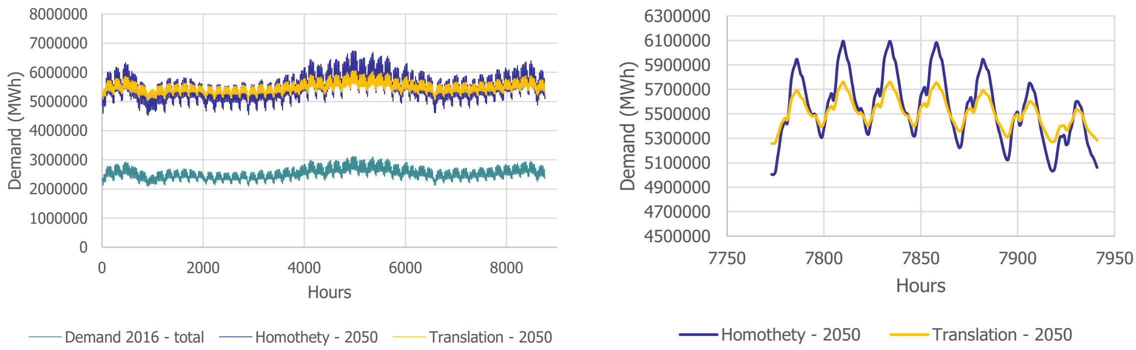


Figure 4-10. The annual load profiles for 2016 and 2050, with homothetic and translation assumptions (left). Detail emphasizing one week of data (right).

In order to properly account for the shifted consumption patterns across regions in the model, as induced by the dispersed geographical positioning of the consumers at different longitudes, the time reference for all demand data is set to Universal Time Coordinated (UTC) time. The collected and processed hourly load profiles (Figure 4-11) provide useful information about currently existing patterns in the use of electricity around the world, with seasonal variations easily observable in some regions. Further investigation of seasonality in load time series is conducted via the equation below, where $\max(2016)$ (resp. $\min(2016)$) represent the 2016 peak load (resp. minimum load) for each region. On this basis, seasonal patterns are considered as being strong when the seasonal effect ratio reaches values above 25%.

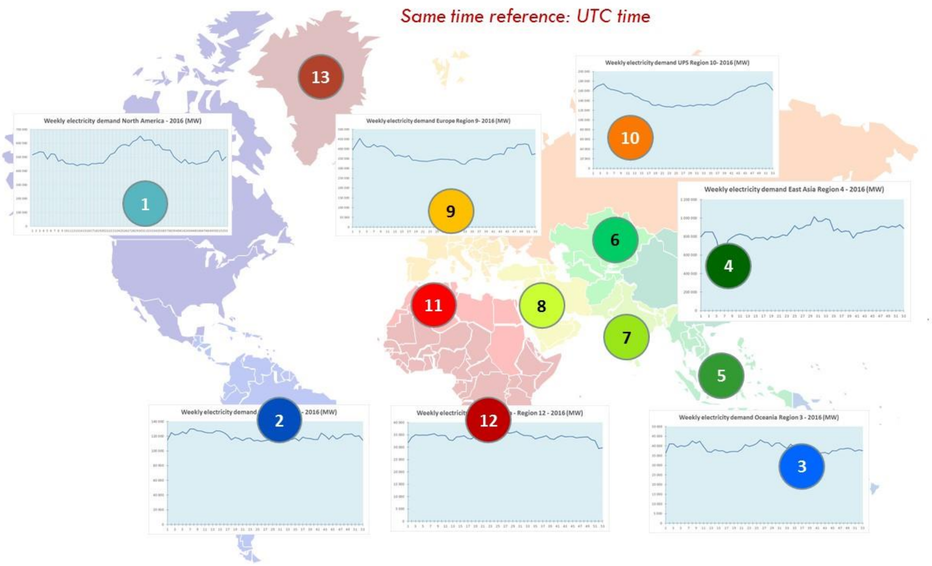


Figure 4-11: Selection of electricity demand profiles for 2016.

$$seasonal_{effect} = \frac{\max(2016) - \min(2016)}{\min(2016)}$$

Figure 4-12 shows that significant seasonal effects can be identified for all but one region in the Northern Hemisphere (with the exception of Region 6, North-West Asia). Region 8 (Middle East) tops this chart, with 62% score, mostly driven by steep electricity demand increase due to cooling requirements over summer time. Several other regions share the same seasonal behavior biased towards summer peaks for similar reasons (e.g., Region 1 – North America, Region 4 – East Asia, Region 11 - North Africa). On the other side, one can observe relatively high seasonal scores for Regions 9 and 10 (i.e., Europe and UPS), which feature their peak demand during winter time, when domestic demand (e.g., for heating or lighting) increases.

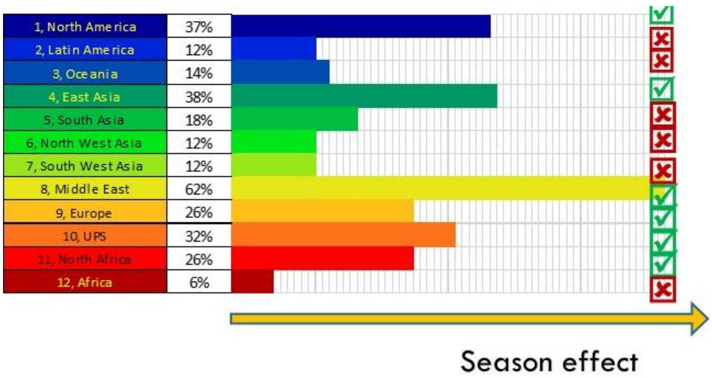
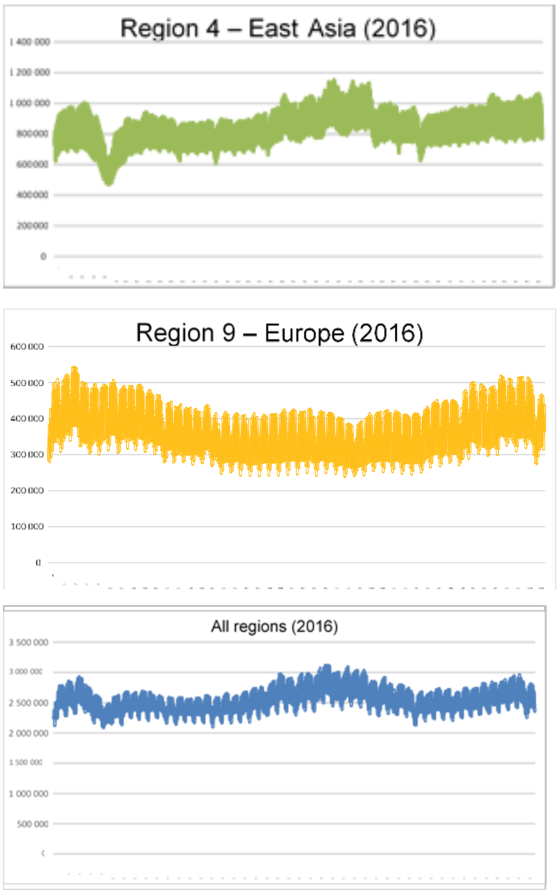


Figure 4-12. Quantification of demand time series seasonality.

The plots and the associated table in Figure 4-13 provide basic information with respect to the yearly amplitude of electricity demand in Regions 4 and 9 (i.e., East Asia and Europe), as well as regarding the potential smoothing effect that may result from the aggregation of all regions via unlimited transmission capacity. For instance, Region 4 is characterized by a peak load which is 36% higher than the average year-round demand (850 GW), while the minimum demand amounts to a 45% decrease from the same average value. In Region 9, a similar situation is observed. Peak load is 45% higher than the average demand over the year (375 GW), while the consumption nadir represents a 36% drop compared to the mean demand. Finally, the aggregation of all demand time series indeed results in a flatter profile throughout the year. In this case, a peak load of 23% above a 2500 GW average demand is recorded, whilst a 17% drop corresponds to the minimum demand year-round.



	Region 4	Region 9	All Regions
Mean (GW)	850	375	2500
Min (%)	- 45	- 36	- 17
Max (%)	36	45	23

Figure 4-13. Statistical properties (e.g., minimum, maximum, mean) of 2016 demand time series for Region 4 – East Asia, Region 9 – Europe and for the aggregation of all regions.

An insightful way to assess the electricity demand variations over different time horizons (e.g., daily or weekly) is to compute heat maps. Figure 4-14 below displays the 2016 electricity demand resulting from the aggregation of all considered regions. In this plot, yellow areas represent the time where electricity load is around the average of the yearly value (i.e., 2500 GW), green areas represent instances when demand is relatively low, while red areas signify time instances when demand is higher than average. It can be observed in this plot that the aggregation of all regions still yields a yearly profile reaching its peak during summer time (due to the influence of high-demand areas, such as Region 1 – North America or Region 4 – East Asia), while preserving the weekly cyclicity currently seen in most of the regions.

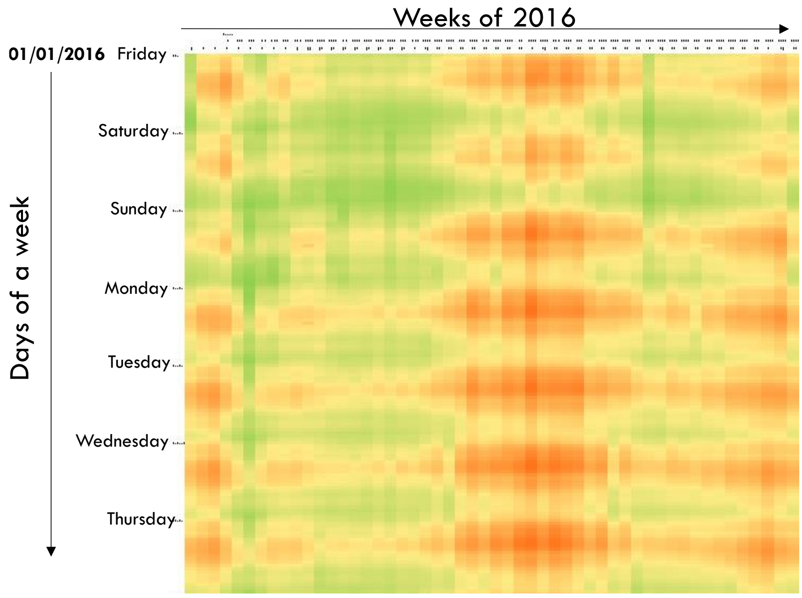


Figure 4-14. Hourly-resolution heat map of electricity demand resulting from the aggregation of all regions during 2016.

This type of visual representation proves useful when trying to identify (on a more qualitative basis) the interconnection potential between the regions included in this study. In this regard, it might be of interest (from a pure signal complementarity standpoint, without considering any other exogenous factors, e.g. the cost of interconnection) to link regions with opposite colors (e.g., green and red) displayed at similar time references. The following figure 4-15 centralizes the heat maps of all regions of interest (with the exception of Region 13 – North Atlantic, given by the assumption of no demand in this area) and provides a first glance on which groups of regions would complement each other from a demand aggregation perspective. For example, the signal in Region 1 (North America) is complementary to the ones in Region 9 (Europe) or Region 10 (UPS), but it is rather correlated with the demand profiles in Region 4 (East Asia) and Region 11 (North Africa). Furthermore, one might say that connecting Region 4 (East Asia) with Regions 5 (South-East Asia), 9 (Europe) or 10 (UPS) is justifiable, but not with Regions 7 (South Asia), 8 (Middle East), or even 3 (Oceania).

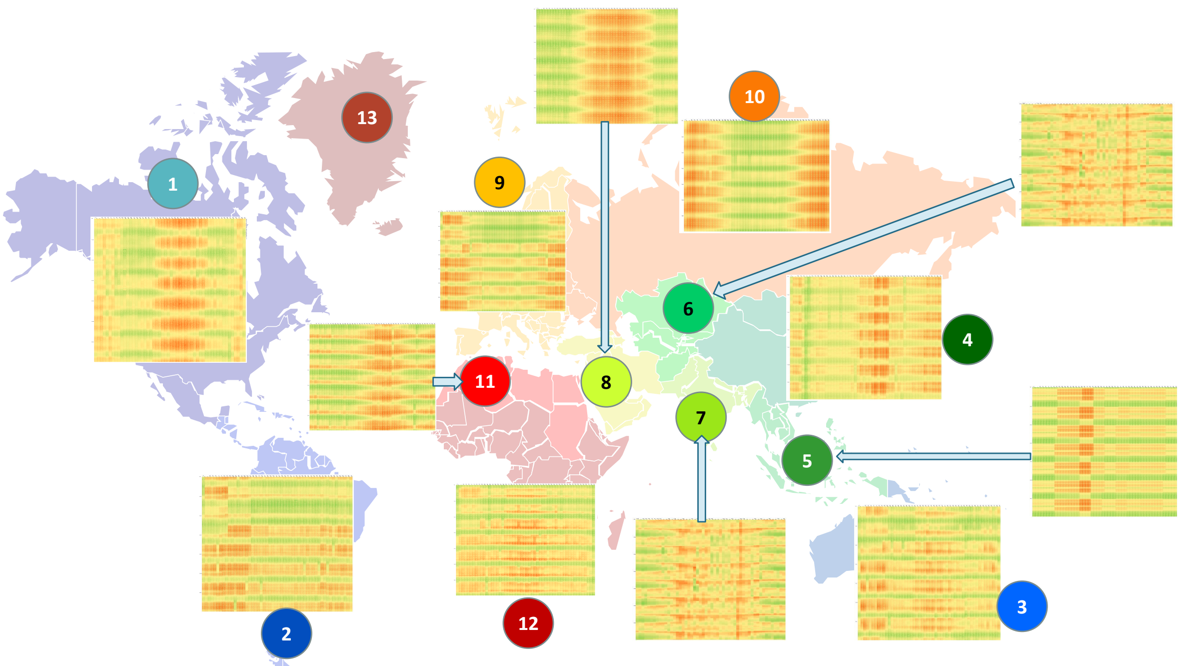


Figure 4-15. Hourly-resolution heat maps of electricity demand for all regions with an associated demand profile (2016).

The data presented in this section, together with the economic assumptions introduced in Chapter 5, will serve as input to the optimization problem defined in Chapter 7. Further information concerning regional generation and demand data is provided in Appendix F.

5. Grid technology

5.1 Interregional high-voltage transmission system

The interregional high-voltage transmission system is a revolutionary technological concept that could play a significant role in the planning and operation of future electric power systems. Historically, the primary justification for building interregional high-voltage transmission lines has been based on economic and reliability criteria. Today, the implementation of renewable portfolio standards, carbon emission regulations, the improvements in the performance of power system electronics, and unused benefits associated with capacity exchange during times of non-coincident peak demand, are driving the idea of designing an interregional high-voltage transmission system. However, there exist challenges related to technical, economic, public policy, and environmental factors that make it challenging to implement of such a complex infrastructure [91].

Many areas are addressing wind power integration challenges in a rapid and efficient way. However, the value of achieving very high wind power generation is still uncertain if wind energy cannot be exported to distant load centers [92]. Most of these preliminary studies agreed on one thing: using interregional transmission is the most cost-effective way to achieve these goals [94 – 97].

When a new line between two areas is to be planned, the solution must consider all aspects of transmission planning, including the current and future power demand, line corridor conditions, operation and maintenance, energy dispatch and overall cost including cost of loss evaluation.

5.2 Drivers and benefits of interregional transmission systems

Interconnection of electric power systems has proven to be an economic alternative that facilitates energy trading between different market structures while guaranteeing the reliability of the network [99]. Traditionally, the main drivers for building interregional high-voltage (HV) transmission lines have been to: provide additional capacity during extreme demand shortages, minimize congestion of transmission capacity, and enable the share of emergency reserves [100]. The preferred option, as discussed below, for this type of interconnection is based on high-voltage direct current (HVDC) transmission lines.

In recent years, additional benefits of HV transmission systems have been identified. These include reduced generation capacity needs to meet future peak demand, reduced reserve capacity requirements to manage variable generation, mitigated curtailment of renewable generation resources, ease of maintenance, and simultaneous power exchange and trading between multiple regions separated by long distances [101].

5.3 Transmission Technologies

There are two available transmission technologies, AC or DC, available for the development of interregional interconnections, and either of these can be selected, depending upon the suitability in the particular application.

5.3.1 Alternating Current (AC) Transmission Technology

Alternating Current (AC) is an electric current which periodically reverses direction, in contrast to direct current (DC) which flows only in one direction. Ultra-High Voltage Alternating Current (UHVAC) refers to AC transmission technology with rated voltage of 1000 kV and above. Compared with lower voltage AC transmission technology, UHVAC can transmit power over much longer distances with larger capacity, decreased line losses, and lower short circuit currents. Since UHVAC has great proven grid interconnection benefits, and higher power supply ability, it can facilitate cross-regional electricity supply, and support the development of large scale clean energy hubs in remote areas.

The first UHVAC project in the world was the 495 km-long Ekibastuz to Kokchetav transmission line, which began operations in 1985. State Grid Corporation of China (SGCC) implemented the first 1000 kV UHVAC pilot project in China, a 640 km-long single-circuit line linking the Northern with the Central China grids. It was commissioned in 2009 and reinforced in 2011 to reach a power transmission capacity of 5 GW [102]. After the implementation of the pilot, the commissioning of seven other 1000 kV UHVAC projects followed in China, with four others under construction in 2019. Also in 2019, Power Grid Corporation of India commissioned a 1200 kV test line in Bina in 2015.

Flexible AC Transmission Technology (FACTS)

Flexible AC Transmission Technology (FACTS) is an AC transmission system concept composed of modern micro and power electronics technology, communication control systems to render the power flow more flexible and its control more responsive. It is intended to enhance system controllability and to increase the transmission capacity of the network.

In order to promote the access of distributed generation resources to the grid, plenty of work on the development and application of flexible AC transmission technology has been carried out recently in Europe. It includes the evaluation of current power grids, the development of hardware equipment, and the coordination of flexible devices in various power companies.

5.3.2 DC Transmission Technology

DC implies unidirectional flow of electric charge. In the mid-1950s, HVDC technology was developed, and is now a significant substitute of long-distance HVAC systems. Since Sweden's Gotland DC transmission project was put into commercial operation in 1954, there have been nearly one hundred DC projects commissioned worldwide, with a cumulated capacity of about 70 GW, mainly built in China, United States, Brazil, Canada, India, Japan and Sweden. Since water resources are usually located far away from load centers, hydroelectric plants often need long-distance power transmission. Thus, the international DC transmission projects are associated with hydropower transmission. There were also applications of DC transmission technology associated with remote coal plants. Such developments relate particular characteristics of DC transmission which satisfy the requirements of stability and reliability of power systems.

The Ultra-High Voltage Direct Current (UHVDC) Transmission Technology refers to DC transmission technology with rated voltage of ±600 KV and above. Compared to UHVAC transmission technology, it holds a series of advantages such as: lower transmission losses, lower operational costs, reduced right-of-ways, improved controllabitlity, as well as the ability of acting as security buffer between AC grids with different system frequencies.

Currently plenty of UHVDC projects are operated or being constructed in China. SGCC currently operates ten UHVDC projects, and two others are under construction, while China Southern Power Grid (CSPG) operates two ±800 kV UHVDC projects, and another one is under construction in 2019.

In addition to China, UHVDC projects have been planned or deployed in other countries, such as Brazil, India, and South Africa, countries with power systems in need of large-capacity power transmission over long distances. Power Grid Corporation of India has commissioned first multi-terminal at UHVDC in 2015 and another 2 UHVDC projects are under construction in 2019.

Currently , among various other technologies, Line-Commutated Converter-Based High-Voltage DC (LCC-HVDC) technology can operate in ultra-high voltage level, and the current highest operation voltage level is ±1000 kV (Zhundong-Wannan UHVDC project in China).

High-Temperature Superconducting Transmission

High-Temperature Superconducting (HTS) transmission refers to power transmission over high-temperature (defined as -180°C and above) superconducting cables.

Compared with the classical power transmission technology, HTS transmission has several technical advantages as shown below:

- It has a larger transmission capacity: a ±800 kV HTS UHVDC line that can transmit 16 GW~80 GW, which is about 2~10 times that of a classical UHVDC.
- It has a lower transmission loss: about 25%-50% of the loss of classical cables.
- Its transmission capacity can be changed by regulating temperature, and fault current can be limited through phase changing.
- It takes less space with lighter weight..

The key of the HTS transmission is the superconducting material technology, where research has been ongoing for several decades already, mainly in the US, Europe, Japan, South Korea and China. HTS materials are mainly composed of bismuth, also known as the first generation HTS material and YBCO , also known as the second generation of HTS material. The length and voltage and power ratings of these cables are still very low. For AC cables, the length ranges from 30m to 1000m, with voltage rating ranging from 10 kV to 138 kV. For DC cables, the length ranges from 200 m to 2500 m and voltage rating ranges from ±1,3 kV to ±80 kV [103].

Currently HTS materials are still to satisfy the requirements of the associated transmission technology and thus are not considered in this study as a viable option.

5.4 Comparison between HVDC and AC alternatives

Both high-voltage transmission options AC or DC are considered. However, DC transmission is widely recognized as being advantageous for long-distance bulk-power delivery, asynchronous interconnections, and long submarine cable crossings.

A comparison of the technological, economic, public policy, and environmental challenges associated with implementing interregional HV transmission systems concludes that DC is the prefered solution over AC for transporting electric power for distances over 600 km [91].

Detailed comparison between DC and AC alternatives in terms of transmission capacity, operation requirements and cost is introduced below.

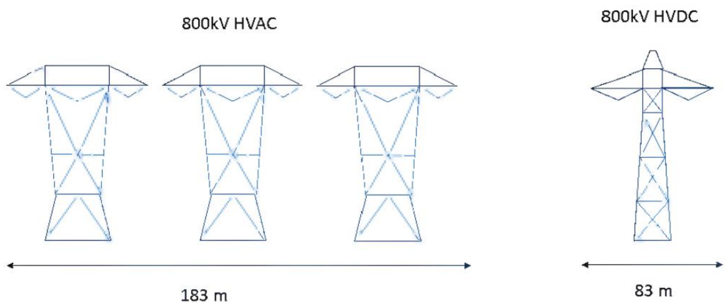


Figure 5-1 - Comparison of Right - of - Way for AC lines and DC lines – same capacity [91]

5.4.1 Comparison of transmission capacity

The power transfer between two networks through an AC overhead transmission line is approximately given by the following expression:

$$P = \frac{V_S V_R}{X_{SR}} \sin\theta_{SR}$$

where V_S and V_R are the voltages at the sending and receiving ends respectively, X_{SR} is the series reactance between the two ends, and θ_{SR} is the load angle (phase difference between the two voltages).

To ensure that synchronism between the two networks is maintained following major disturbances, the load angle is kept low during steady state operation. As a result, the power transfer capability of AC line is reduced compared to its thermal capability. This problem does not exist with an HVDC system, as the two networks are decoupled, and the power can be independently controlled by the HVDC system.

For HVAC cable transmission over certain distances, the charging current becomes a major contributor to the thermal loading of the cable, due to its large shunt capacitance. This therefore limits the useful load that the AC transmission circuit can carry. With DC transmission, no charging current problems occur and therefore the useful load is also generally only limited by the thermal capability of the cable [104].

5.4.2 Comparison of operation requirements

Comparison of system fault and stability

Faults causing significant voltage variation or power swings do not transmit across an HVDC link. They may emerge on the other end of an HVDC link simply as a reduction in power, without causing severe disturbances.

Contrary to AC transmission, HVDC does not significantly increase the short circuit currents in both sending and receiving end of AC power networks.

An HVDC link does not suffer from the power angle stability problems which frequently occur with long AC transmission lines. Also, an AC transmission line is sensitive to disturbances of the power balance in AC power networks, and the power flow within AC lines is not easy to be controlled, whereas the controllability of an HVDC system can be used to support the stability of the connected AC networks by power runback or run-up. Furthermore, an HVDC link can provide additional benefits, like possible overload, reduced voltage operation. However, for a short time during a transient, an AC line may be able to transmit more power than a DC link, even beyond its steady state thermal capacity, while the transient overload allowed by the converter stations is usually smaller [104].

Comparison of voltage regulation and reactive power compensation

An AC transmission line imposes a load-dependent reactive power demand which may impact the active current rating, and may require reactive power compensation at the terminals, as well at points along the line, to ensure the desired voltage level and adequate active power transfer capability. While series or shunt compensation can assist overhead line transmission, a technical limit is encountered in the case of transmission through insulated cables. Even at relatively short distances, the reactive power consumes the greater part of the current carrying capacity of the cable. Such solutions are possible, but inconvenient.

HVDC systems do not need this type of compensation and therefore do not present the same technical limitations in long transmission distance, with no requirement for special compensation along the line/cable [104].

5.4.3 Comparison of cost

While comparing different options, the listed items below should be evaluated and compared from a monetary point of view:

- stations costs;
- line costs;
- integration costs;
- capitalised cost of converter station and DC line losses during the life of the project;
- operational costs;
- maintenance costs;
- decommissioning costs;
- land acquisition and right of way.

For bulk power transfer over long distances, an HVDC transmission project has lower costs, while an HVAC transmission project is cheaper for short distance transmission of the same power. There exists a “breakeven distance” at which HVDC and HVAC transmission projects have the same cost.

The comparison is shown in Figure 5-2. Many factors contribute to the cost of AC and DC transmission, including ratings, locations, terrain, losses, etc., therefore the determination of the actual breakeven distance for a particular transmission system must be carried out on a case-by-case basis. The break-even distance for overhead lines is typically around 600 to 800 km. For transmission by submarine cables the break-even distance occurs around 40 to 120 km [104].

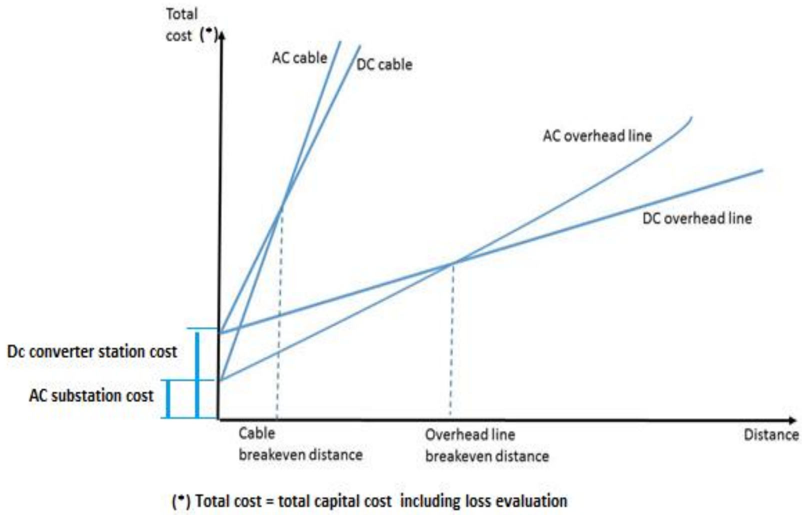


Figure 5-2 – The break-even distance of high voltage AC and DC technologies [104]

5.5 Core HVDC technologies & applications

Two basic converters VAC technology are used in modern HVDC transmission systems. These are conventional line-commutated current source converters (CSCs, also called LCCs) and self-commutated voltage source converters (VSCs). Figure 5-3 shows a conventional HVDC converter station with CSCs while Figure 5-4 shows a HVDC converter station with VSCs.

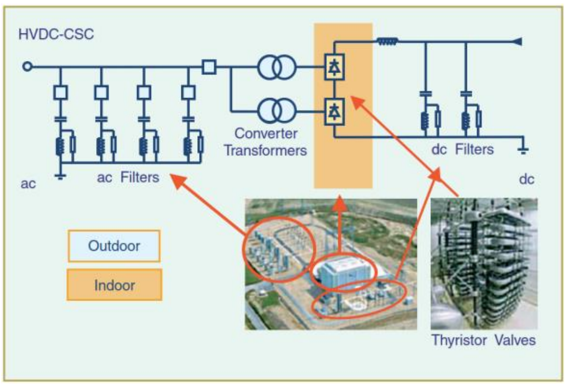


Figure 5-3 – Conventional (LCC) HVDC with current source converter [98]

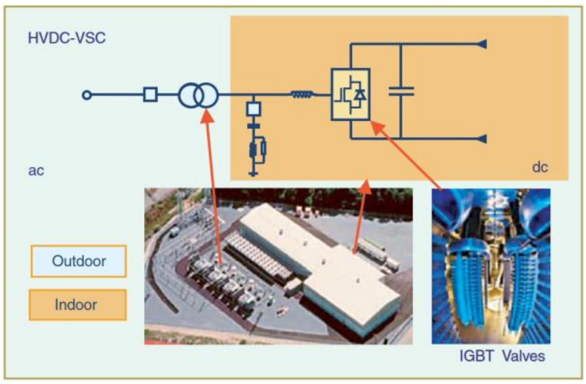


Figure 5-4 – HVDC with voltage sourced converters (VSC) [98]

5.5.1 Line-Commutated Current Source Converter (LCC)

Conventional/classical HVDC transmission employs line-commutated LCC with thyristor valves. Such converters require a synchronous voltage source in order to operate. The basic building block used for HVDC conversion is the three-phase, full-wave bridge referred to as a six-pulse or Graetz bridge.

5.5.2 Self-Commutated Voltage Source Converter (VSC)

HVDC transmission using VSCs with pulse-width modulation (PWM), commercially known as HVDC Light, was introduced in the late 1990s. Since then the progression to higher voltage and power ratings for these converters has roughly paralleled that for thyristor valve converters in the 1970s. These VSC-based systems are self- commutated with insulated-gate bipolar transistor (IGBT) valves and solid-dielectric extruded HVDC cables. Figure 5-5 illustrates solid-state converter development for the two different types of converter technologies using thyristor valves and IGBT valves.

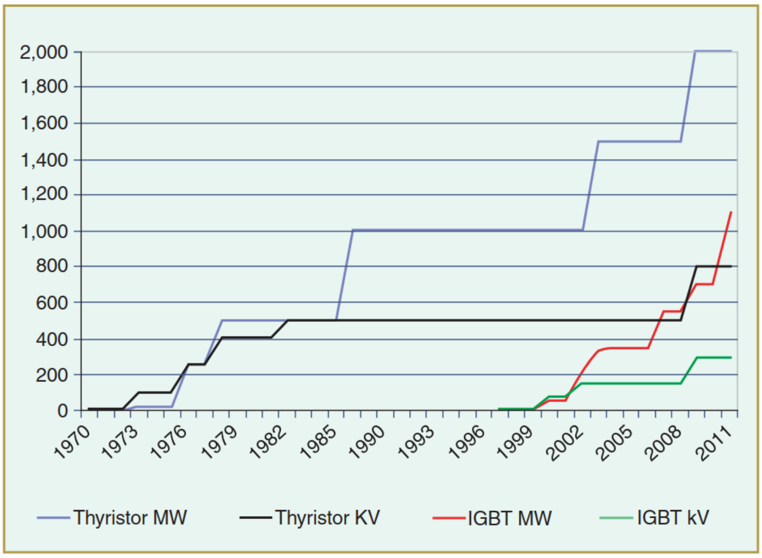


Figure 5-5 - Solid-state converter development [98]

HVDC transmission with VSCs can be beneficial to overall system performance. VSC technology can rapidly control both active and reactive power independently of one another. Reactive power can also be controlled at each terminal independent of the DC transmission voltage level. This control capability gives total flexibility to place such converters anywhere in the AC network since there is no restriction on minimum network short-circuit capacity. Self-commutation with VSC even permits black-start; i.e., the converter can be used to synthesize a balanced set of three phase voltages like a virtual synchronous generator. The dynamic support of the AC voltage at each converter terminal improves the voltage stability and can increase the transfer capability of the sending- and receiving-end AC systems, thereby leveraging the transfer capability of the DC link.

Unlike conventional (LCC) HVDC transmission, the converters themselves have no reactive power demand and can actually control their reactive power to regulate the AC system voltage just like a generator. Each VSC-HVDC in the system can be controlled independently according to the operating condition in the adjacent AC system, which saves lots of cost on protection device and equipment maintenance.

Currently, there are about 30 of VSC-HVDC projects in operation all over the world, mainly in Europe, China, and the United States. They are implemented for various purposes, including grid interconnection, offshore wind power integration, as well as for power supply to offshore oil or gas platforms and to large cities.

The voltage and power ratings of VSC-HVDC are still relatively low as compared to LCC-HVDC due to the limited availability and high cost of valves and cables. Currently, the available maximum voltage and power ratings for VSC-HVDC are 500 kV and 2 GW, but they are expected to increase steadily.

5.5.3 Long-Distance Bulk Power

Higher power transfers are possible over longer distances using fewer lines with HVDC transmission than with AC transmission. Typical HVDC lines utilize a bipolar configuration with two independent poles, one at a positive voltage and the other at a negative voltage with respect to ground. Bipolar HVDC lines are comparable to a double circuit AC line since they can operate at half power with one pole out of service but require only one-third the number of insulated sets of conductors as a double circuit AC line.

The controllability of HVDC links offer firm transmission capacity without limitation due to network congestion or loop flow on parallel paths. Controllability allows the HVDC to “leap-frog” multiple “choke-points” or bypass sequential path limits in the AC network. Therefore, the utilization of HVDC links is usually higher than that for extra high voltage AC transmission, lowering the transmission cost per MWh. This controllability can also be very beneficial for the parallel transmission since, by eliminating loop flow, it frees up this transmission capacity for its intended purpose of serving intermediate load and providing an outlet for local generation.

Whenever long-distance transmission is discussed, the concept of “break-even distance” frequently arises. This is where the savings in line costs offset the higher converter station costs. A bipolar HVDC line uses only two insulated sets of conductors rather than three. This results in narrower rights-of-way, smaller transmission towers, and lower line losses than with AC lines of comparable capacity. A rough approximation of the savings in line construction is 30%. Although break-even distance is influenced by the costs of right-of-way and line construction.

Furthermore, the long-distance AC lines usually require intermediate switching stations and reactive power compensation. This can increase the substation costs for ac transmission to the point where it is comparable to that for HVDC transmission.

5.5.4 Underground and submarine cable transmission

Unlike the case for AC cables, there is no physical restriction limiting the distance or power level for HVDC underground or submarine cables. Underground cables can be used on shared rights-of-way with other utilities without impacting reliability concerns over use of common corridors.

For underground or submarine cable systems there is considerable savings in installed cable costs and cost of losses when using HVDC transmission. Depending on the power level to be transmitted, these savings can offset the higher converter station costs at distances of 40 km or more. Furthermore, there is a drop-off in cable capacity with AC transmission over distance due to its reactive component of charging current since cables have higher capacitances and lower inductances than AC overhead lines. Although this can be compensated by intermediate shunt compensation for underground cables at increased expense, it is not practical to do so for submarine cables.

For a given cable conductor area, the line losses with HVDC cables can be about half those of AC cables. This is due to AC cables requiring more conductors (three phases), carrying the reactive component of current, the skin-effect, and also induced currents in the cable sheath and armor.

With a cable system, the need to balance unequal loads or the risk of post-contingency overloads often necessitates use of a series-connected reactors or phase shifting transformers. These potential problems do not exist with a controlled HVDC cable system.

Extruded HVDC cables with prefabricated joints used with VSC-based transmission are lighter, more flexible, and easier to connect than the mass-impregnated oil-paper cable (MINDs) used for conventional HVDC transmission, thus making them more conducive for land cable applications where transport limitations and extra splicing costs can drive up installation costs. The lower-cost cable installations made possible by the extruded HVDC cables and prefabricated joints makes long-distance underground transmission economically feasible for use in areas with rights-of-way constraints or subject to permitting difficulties or delays with overhead lines.

5.5.5 HVDC Transmission system configurations

LCC HVDC Transmission can be configured in several topologies/configurations [104]. To name a few:

- Monopolar HVDC transmission system with earth/sea return
- Monopolar HVDC transmission systems with dedicated metallic return
- Bipolar HVDC transmission system with earth/sea return
- Bipolar HVDC transmission with dedicated metallic return
- Rigid bipolar HVDC system

VSC HVDC Transmission can be configured in several topologies/configurations [105]. To name a few:

- Symmetrical Monopolar HVDC transmission system
- Asymmetrical Monopolar HVDC transmission system
- Bipolar HVDC transmission system with earth/sea return
- Bipolar HVDC transmission with dedicated metallic return

The final configuration for each transmission/interconnection is decided after evaluation on number of techno-economic factors such as reliability/availability requirements, loss evaluation, possibility of using earth/sea return etc.

In bipolar HVDC transmission topology, there are two poles of opposite polarity connected together at each end, with at least one of the terminals connected to the earth. The HV terminals of the same polarity are connected together by overhead lines, cables, or a combination of both. The low-voltage terminals of the two converters at each end are connected together and may be connected to earth through an electrode line (bipolar HVDC system with earth return), or to each other through a cable or line conductor. The bipolar HVDC transmission topology is the most commonly used when an HVDC transmission line connects two HVDC converter stations. The bipolar HVDC system with earth return may be designed such that when one pole converter is out of service, the healthy pole may use the faulty pole's HV line as a metallic return.

The advantages of the bipolar topology compared to monopolar are as follows [104]:

- Lower losses for a given transmitted power;
- A pole outage means only a 50% of the total power transfer capability of the HVDC link is lost. Due to this, a bipole HVDC link is compared to double circuit AC line.;
- Overload capability may be incorporated into the rating of each pole, such that when one pole is out of service the healthy pole may pick up some of the faulted pole power, leading to some contingency power capability above 50%, although this is scheme-specific;
- Lower earth current flow.

The disadvantages of this topology (compared to monopolar) include the following:

- Higher converter station costs;
- More converter station equipment and therefore more land usage.

5.6 Voltage selection of transmission

The voltage level of any interconnection, AC or DC, is selected considering the amount of power to be transmitted together with the distance of the transmission link.

For an HVDC transmission system, the rated voltage is selected through careful analysis considering aspects including total investment and operation cost.

Table 5-1 lists typical rated voltage ranges under various transmission powers and distances [104].

Table 5-1: Typical overhead bipolar HVDC project for power transmission

	Up to 200 km	Up to 500 km	Up to 1 000 km	Up to 1 500 km	Up to 2 000 km	2 000km & more
Up to 500 MW	250kV	400 kV	----------------	----------------	----------------	----------------
UP to 1 000 MW	350kV	400 kV	500 kV	----------------	----------------	----------------
Up to 3 000 MW	----------------	500 kV, 600 kV	500 kV, 600 kV	600 kV, 800 kV	600 kV, 800 kV	800 kV
Up to 4 000 MW	----------------	600 kV	600 kV, 800kV	800 kV	800kV	800 kV
Up to 6 000 MW	----------------	800 kV	800 kV	800 kV	800 kV	800 kV
6000MW & More	----------------	800 kV	800 kV	800 kV	800 kV or more	800 kV or more

As the cost depends a lot on the terrain and country, Table 5-1 could be considered as reference and project specific calculations must be made. HVDC transmissions up to 1100 kV DC has already been commissioned and utilized for power transmission.

For further detailing and studies, IEC/TR 63179, Guideline for planning of HVDC System, is recommended [104].

6. Technology costs

6.1 transmission assets

6.1.1 Cost references of past studies

This section details the power transmission equipment's cost projection used in the investment loop of the economic model proposed by the present feasibility study.

According to C1.35 group investigations, power transmission cost projection is mainly driven by decreasing equipment costs due to yet untapped economies of scale. At the same time, the lack of social acceptance is more and more difficult to be obtained. Finally, various underlying land types, flat land, hill, swamp, forrest, mountain, etc.., can easily inflated the development cost associated with a particular transmission project.

In this framework, it has been decided to consider only three main power transmission technologies: HVDC OHL (Over Head Line), HVAC OHL and HVDC USC (Under Sea Cable).

The reference considered here for the 2050 cost projections is the e-Highway2050 project [10].

HVDC Overhead Line:

For HVDC OHL costs are centralized in table 6.1:

Table 6-1 - e-Highway 2050 study projection costs for HVDC OHL [10]

Voltage (kV)	320	500	800	1100
CAPEX (k€/km)	1068-1602	1423-2134	1780-2670	2225-3337
OPEX (k€/km/year)	6-10	9-13	11-16	22-33

So, taking capacity of 800 kV HVDC line as 8 GW, one obtains a specific cost range of 0.22 to 0.33 M€/km/GW (0.28 M$/km/GW).

Considering the capacity of of 1100 kV UHVDC line as 12GW one gets a specific cost range of 0.18 to 0.28 M€/km/GW (0.23 M$/km/GW).

Thus HVDC OHL costs to be used in the currency study range between 0.18 M€/km/GW and 0.33 M€/km/GW.

HVDC Underground Cable:

For HVDC USC, costs are centralized in Table 6.2.

Table 6-2 - e-Highway 2050 project projection costs for HVDC Cables, XLPE, 320 kV [10]

1600	k€/km			1	1		0,95	1,05		0,9	1,1		0,85	1,15		0,8	1,2
Breakdown per component (% of investment cost)		costs for each component		k€/km 2014		k€/km 2020			k€/km 2030			k€/km 2040			k€/km 2050		
		Labor	OIL	min	max	index	min	max	index	min	max	index	min	max	index	min	max
Equipment	59%			944	944		804	888		692	846		613	829		549	824
						EXP 0,90			0,81			0,76			0,73		
Installation	4%	60%	40%	64	64		64	70		63	78		64	86		64	96
						LAB 0,98			0,95			0,92			0,89		
						OIL 1,14			1,33			1,54			1,79		
Civil works	11%	50%	50%	176	176		177	196		180	220		184	249		189	283
						LAB 0,98			0,95			0,92			0,89		
						OIL 1,14			1,33			1,54			1,79		
Project managnt	14%	100%		224	224	ENG 1,14	243	269	1,34	271	331	1,55	294	398	1,75	313	470
Right of ways	12%			192	192	N/A	182	202		173	211		163	221		154	230
CAPEX (k€/km)	100%			1600	1600		1470	1625		1380	1686		1318	1783		1269	1903
OPEX (p.a.)	0,2%			3,20	3,20		2,94	3,25		2,76	3,37		2,64	3,57		2,54	3,81

Since the data above is for a 320 kV and 1GW link, taking this yields a specific cost range of 1.27 to 1.90 M€/km/GW for HVDC underground cables. An identical cost structure is assumed for submarine cables.

Cost of HVDC Converters:

For HVDC USC, costs are centralized in Table 6-3:

Table 6-3 - e-Highway 2050 study projected for LCC convecters [10]

110	M€/MW			1	1			0,95	1,05		0,9	1,1		0,85	1,15		0,8	1,2
Breakdown per component (% of investment cost)		costs for each component		M€/GW 2014				M€/GW 2020			M€/GW 2030			M€/GW 2040			M€/GW 2050	
		Labor	OIL	min	max		index	min	max	index	min	max	index	min	max	index	min	max
Equipment	69%			76	76			71	78		60	74		54	72		47	71
						EXP	0,98			0,89			0,83			0,77		
Installation	0%	60%	40%	0	0			0	0		0	0		0	0		0	0
						LAB	0,98			0,95			0,92			0,89		
						OIL	1,14			1,33			1,54			1,79		
Civil works	14%	50%	50%	15	15			16	17		16	19		16	22		17	25
						LAB	0,98			0,95			0,92			0,89		
						OIL	1,14			1,33			1,54			1,79		
Project managnt	17%	100%		19	19	ENG	1,14	20	22	1,34	23	28	1,55	25	33	1,75	26	39
Right of ways	0%			0	0	N/A		0	0		0	0		0	0		0	0
CAPEX (M€/GW)	100%			110	110			106	118		99	121		94	128		90	135
OPEX (p.a.)	2,0%			2,20	2,20			2,13	2,35		1,98	2,42		1,89	2,55		1,79	2,69

Table 6-4 - e-Highway 2050 study projected costs for VSC convecters [10]

125	M€/MW			1	1			0,95	1,05		0,9	1,1		0,85	1,15		0,8	1,2
Breakdown per component (% of investment cost)		costs for each component		M€/GW 2014				M€/GW 2020			M€/GW 2030			M€/GW 2040			M€/GW 2050	
		Labor	OIL	min	max		index	min	max	index	min	max	index	min	max	index	min	max
Equipment	63%			79	79			67	74		60	73		53	72		50	74
						EXP	0,90			0,84			0,80			0,79		
Installation	0%	60%	40%	0	0			0	0		0	0		0	0		0	0
						LAB	0,98			0,95			0,92			0,89		
						OIL	1,14			1,33			1,54			1,79		
Civil works	22%	50%	50%	28	28			28	31		28	34		29	39		29	44
						LAB	0,98			0,95			0,92			0,89		
						OIL	1,14			1,33			1,54			1,79		
Project managnt	15%	100%		19	19	ENG	1,14	20	22	1,34	23	28	1,55	25	33	1,75	26	39
Right of ways	0%			0	0	N/A		0	0		0	0		0	0		0	0
CAPEX (M€/GW)	100%			125	125			115	127		111	135		107	145		105	158
OPEX (p.a.)	2,0%			2,50	2,50			2,31	2,55		2,21	2,70		2,14	2,89		2,10	3,16

For the purpose of this study, the cost range of HVDC convecter stations is defined between the minimum value associated with LCC stations and the maximum cost obtained from VSC convecter data. This results into a specific cost range of 90 to 158 M€/GW.

Based on all above mentioned costs, a synthesis of the 2050 cost projections is displayed in Table 6.5.

Table 6-5 - e-Highway2050 study projection costs

Cost	HVDC OHL	HVDC USC	AC/DC converter
Maximum	0.33(M€/km/GW)	1.90(M€/km/GW)	158 M€/GW
Minimum	0.22(M€/km/GW)	1.27(M€/km/GW)	90 M€/GW

6.1.2 Cost references from China

Through massive investments in this field, China has become the world leader in HVDC/HVAC OHL development with more than 33000 km of such ties currently in operation and under construction. The costs associated with chinese practice are considered to be a robust information base for further C1.35 assumptions.

Table 6.6, presents the range of costs for the key-transmission elements.

Table 6-6 – The HVDC/HVAC Costs from China's Practice [106]

	HVDC OHL (M€/km)	HVDC USC (M€/km)	HVAC OHL (M€/km)	AC/DC converter (M€/GW)
Maximum	0.26	1.33	0.62	65
Minimum	0.18	1.27	0.16	65

6.1.3 Cost reference used in feasibility study

Table 6-7 displays the transmission technology 2050 cost assumptions used within the investment model proposed in this fesaibility study.

Table 6-7 - Summary of transmission infrastructure cost projections for C1.35 economic study

Cost (M€)	**DC OHL** (M€/km/GW)	**DC USC** (M€/km/GW)	**AC OHL** (M€/km/GW)	**AC/DC Converter** (M€/GW for one SS)	**AC/AC Back to Back SS** (M€/GW for one SS)
Max	0,33	1,90	0,25	158	158
Min	0,18	1,27	0,13	90	90

The present feasibility study has limited the grid architecture to only one electrical node per region, resulting into a total of 13 nodes. This granularity is considered enough to provide an meaningful quantitative results considering the plethora of uncertainty factors specific to such long term studies (+30 years).

Moreover, an interconnection between two regions is represented by only one corridor, that should be understood as the aggregation of multiple physical lines with a total capacity equal to the summation of all links.

The technologies considered are AC/DC OHL, and DC cables, on-shore and subsea cables. Moreover, only a selection of 20 interconnections between the considered model nodes have been considered. For each of this links, the underlying technology AC or DC is defined, based on expert assessment while its size is determined by the optimization tool employed.

Table 6-8 lists all the potential interconnections available in the model with their corresponding connection points lengths and specific costs.

Finally, in order to limit the simulation cases, 20 interconnections have been selected (see Table 6-8 below).

Table 6-8 - List of interconnections considered in feasibility study

Region from		Region to		Length			Cost	
Place	No.	Place	No.	DC OHL [km]	DC USC [km]	AC OHL [km]	Avg [M€/GW]	Share [%]
NE Asia Hebei (CHN)	4	**UPS** Irkoutsk (RUS)	10	1600			656	2.2
NE Asia Xinjiang (CHN)	4	**C Asia** Astana (KHZ)	6	1700			682	2.3
C Asia Astana (KHZ)	6	**UPS** Chelyabinsk (RUS)	10	1000			503	1.7
Europe (DEU)	9	**UPS** Moscow (RUS)	10	1700			682	2.3
Europe (BGR)	9	**Middle East** Tehran (IRN)	8	2800			962	3.3
Europe La Spezia (ITL)	9	**North-Africa** (TUN)	11	400	800		1618	5.5
Europe (PRT)	9	**North-Africa** Rabat (MAR)	11	600	200		718	2.5
Europe Athens (GRC)	9	**North-Africa** Suez (EGY)	11	200	1100		2043	7.0
Africa Inga (RDC)	12	**North-Africa** Rabat (MAR)	11	6400			1880	6.4
Africa Inga (RDC)	12	**North-Africa** Aswan (EGY)	11	4500			1396	4.8

Africa Addis Abeba (ETH)	12	**Middle East** Rhyad (SAU)	8	2500	50		965	3.3
Middle East Rhyad (SAU)	8	**North-Africa** Suez (EGY)	11	1700			682	2.3
Middle East Rhyad (SAU)	8	**UPS** Vogodonsk (RUS)	10	3100			1009	3.4
Middle East Tehran (IRN)	8	**C Asia** Kabul (AFG)	6	1700			680	2.3
C Asia Kabul (AFG)	6	**S Asia** Islamabad (PAK)	7		400		200	0.7
NE Asia Yunan (CHN)	4	**S Asia** Mandalay (MMR)	7	1000			503	1.7
SE Asia Bangkok (THA)	5	**S Asia** Mandalay (MMR)	7	1200			554	1.9
NE Asia Nanning (CHN)	4	**SE Asia** Hanoi (VNM)	5		400		200	0.7
Oceania Darwin (AUS)	3	**SE Asia** Java (IDN)	5		2300		3894	13.3
N America Vancouver (CAN)	1	**UPS** Irkoutsk (RUS)	10	9400			2804	9.6
N America Ch. Falls (CAN)	1	**N. Atlantic** (GRL)	13	1100	1000		2114	7.2
Europe (GBR)	9	**N. Atlantic** (GRL)	13	700	2000		2846	12.3
Latin America Medellin (COL)	2	**N America** Chiapas (MEX)	1	2600			911	3.1
				Total	54250 km		29280	100

6.2 generation costs

As explained in more detail throughout the upcoming chapter, the simulations performed in this study consider fixed and variable costs of electricity generation in this regard.

Table 6.9 summarizes the numerical values selected as input for various production technologies considered, as provided by IEA source [75].

Table 6-9 – Unit costs for generation coming from IEA data base and used buy C1.35 [75]

	CAPEX invest (€/kW)	fixed OPEX (% CAPEX/yr)	life duration (years)	variable cost except CO2 (€/MWh)	CO2 emissions (t/MWh)	fixed annual costs (k€/MW/yr)	unit variable cost (€/MWh)
Hydro	2 300	1,1%	80	0	0	187	0
Biomass	2 441	2,9%	30	49	0	268	49
Nuclear	3 644	1,8%	60	10	0	325	10
Coal with CCS	3 804	1,5%	40	15	0,080	342	24
Wind	836	2,5%	25	0	0	93	0
Solar PV	448	1,0%	25	0	0	43	0
CCGT with CCS	1 475	1,5%	30	36	0,037	141	40
CCGT	700	1,5%	30	36	0,370	67	77
OCGT	505	1,2%	30	45	0,469	47	97

The operational costs of hydro, biomass, nuclear and coal with CCS technologies units are all considered in the estmation of the optimal system cost. However their capacities are exogenous parameters derived from corresponding production volumes provided in the Unfinished Symphony scenario of the World Energy Council [74].

Variables costs

Fuel prices for gas and coal, as well as CO2 prices are considered based on previous IEA hypotheses [63]. However, according to these hypotheses, the primary resource or CO2 prices vary across different regions, a relevant feature for relatively independent regions. In our study, a single price was considered across all regions in order to assess the value of the corresponding interconnection, while in the same time avoiding undesired effects such as thermal electricity imports from regions with lower CO2 prices. Thus an average value across all regions is considered which leads to following prices:

- CO2 : 110 €/ton.
- Gas : 6 €/MBTU.
- Coal : 55 €/ton.

Additionally table 6-10 displays a set of additional technical parameters required.

Table 6-10 – parameters taken into account for CO2 emission by thermal plants

Technology	Heating value	Efficiency	CO2 emissions (kg/MWh elec)
Gas CCGT	0,29 MWh/MBTU	57%	370
Gas OCGT	0,29 MWh/MBTU	45%	469
Coal	8,50 MWh/ton	43%	800

Fixed costs

As for the variable costs, fixed costs of electricity generation are assumed to be constant across regions for a given technology [84, 85, 75].

Certain assumptions were made considering available power generation technologies. Considering PV generation, solely utility-scale units are considered, while residential, commercial, smaller-scale units are completely disregarded. With the latter being often times connected at distribution levels of power grids, the aforementioned choice comes naturally given the focus of the current study on transmission level infrastructure.

Considering wind generation, only onshore deployments are considered in the model.

Finally, some technologies considered in [74], but accounting for small volumes of generated power in 2050, are not included in this study. Examples of such technologies include: coal without CCS, oil based units, geothermal plants, biomass with CCS.

For the Carbon Capture and Storage (CCS) technologies, we assume a capture efficiency of 90%.

7. Methodology

7.1 Objective and constraints

The objective of the proposed sizing problem is to find the optimal combination of genration and transmission interconnection capacity that minimizes the total cost of the system, including:

- Annual investment and fixed costs of generation and transmission assets;
- Variable costs of production.

The costs of transmission and distribution within each of the 13 regions are not considered: each region is assumed to be a “copper plate”.

This optimal decision is sought under the following constraints:

- The electricity demand of each region must be satisfied on an hourly basis, including losses in interconnections and storage devices. However, this constraint can be violated at a loss of load cost of 10 000 €/MWh (this loss of load can be seen as a theoretical power plant of infinite capacity and a unit variable cost of 10 000 €/MWh).
- The hourly production of dispatchable power plants cannot exceed the installed capacity of the associated generating units for each technology and each region. Other dynamic constraints such as minimum power, up and down ramps are not considered here, as it would induce a false precision considering the level, as well as the other assumptions made e.g the copper plate within each region.
- The normalized production of run-of-river plants (e.g wind, solar, hydro) for a given zone and a given time step is limited by the corresponding input capacity factors. However, curtailment of those productions is allowed, at zero cost.
- The flows in each interconnection (in either direction) cannot exceed their rated capacity.
- Constraints on storages are taken into account: e.g maximum power (assumed to be identical for in-flows or out-flows) and energy balance over a given period (24 hours for daily storage, a year for seasonal storage) also taking into account efficiency losses.

Therefore for each of the 13 regions and for any hourly time step the following equality is respected:

$$\begin{aligned} &sum\ of\ productions - curtailments + imports + loss\ of\ load \\ &\qquad = demand + exports + losses\ in\ exporting\ interco + losses\ in\ storages \end{aligned}$$

Modeling and calculation with ANTARES

For the purpose of this study, ANTARES was used as an optimization tool [90]. ANTARES is a probabilistic software developed by RTE to assess adequacy and undergo economic studies of electric power systems.

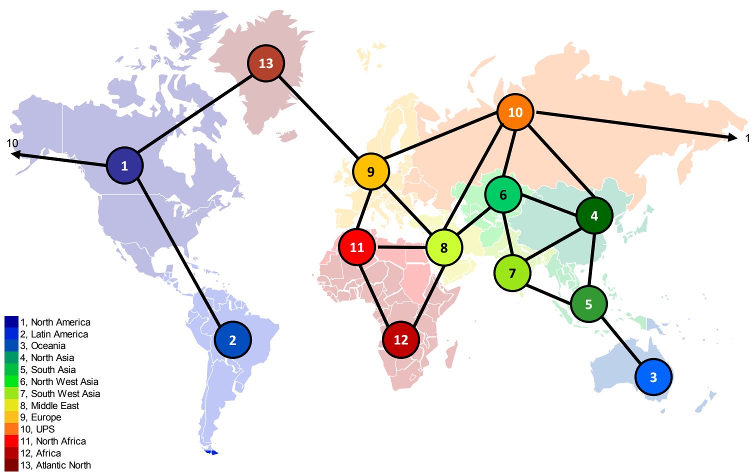


Figure 7-1 Electrical nodes used for the simulation with Antares.

Each of the 13 regions is described by its corresponding:

- hourly electricity load curves for a set of different climate scenarios;
- generation technologies with their annualized fixed and unit variable costs;

- run-of-river generating units (e.g wind, solar, hydro) with their annualized fixed costs, and hourly sampled capacity factors.

Each interconnection link is described by its corresponding annualized fixed costs.

At the core of ANTARES, there is a simulation tool that for given capacities of production technologies and interconnections, optimizes the unit commitment (hourly use of each plant, storage and interconnection) in order to meet the demand at the lowest operational cost. This is achieved by solving an integer linear programming (ILP) problem.

The simulator minimizes the variable cost part, as this part can be modeled as a linear problem. But the search for the optimal system cost requires to take into account fixed cost part of the total cost as well. The complexity of such a problem requires an iterative procedure with successive calls to the ANTARES simulator. At each call the capacities that can be optimized (either for production or interconnections) are modified until the minimum total system cost is reached. This is achieved within a package called Antares Xpansion, an optimization procedure following a Benders decomposition technique.

ANTARES is an open-source software. More information about this modelling tool can be found on a dedicated website [107].

Fixed costs

The fixed costs include the initial investment costs (capital expenditures or CAPEX) and the fixed operation and maintenance costs (fixed operational expenditures or OPEX). To compare the costs of different production technologies, and especially take into account the life duration of power plants, the costs are annualized, and expressed in €/MW/year.

The initial investment cost are assumed to be “overnight” expenses, just as if the plant could be financed and built from one day to another. The initial investment cost is annualized over the life duration of the plant, with the associated cost of capital representing a hurdle rate required by companies, due to the cost of debt or the cost of equity. The part of the fixed cost depends on three parameters:

- The initial investment (in €/MW) : ***I***
- The life duration of the plant (in years) : ***d***
- The weighted average cost of capital (in %/year) : ***r***

The annualized fixed investment cost ***a*** is then given by the following formula:

$$a = I \times \frac{r}{1-(1+r)^{-d}}$$

The fixed operation and maintenance costs ***O&M*** (in €/MW/year) are often expressed as a portion of the initial investment costs to be paid each year (in the usual order of magnitude of a few percent). They are called “fixed” as they are supposed not to depend on the use rate or load factor of the power plant (which could be argued considering that aging of machines should depend – at least partly – on the use rate of plants).

Variable costs

The unit variable costs are expressed in €/MWh. They depend on :

- The fuel cost ***f*** (in €/unit of fuel).
- The efficiency of the plant ***e*** (in MWh/unit of fuel cost).
- The CO2 emission rate r_{CO2} (in tons of CO2/MWh).
- The CO2 price p_{CO2} (in €/ton of CO2).

The unit variable cost ***u*** (in €/MWh) is given by the formula:

$$u = \frac{f}{e} + r_{CO2} \times p_{CO2}$$

The variable costs ***V*** are given by multiplying the unit variable costs ***u*** and the energy ***E*** produced by the plant.

As illustrated in Figure 7.2, the total annual cost of a power plant is a linear function depending on the fixed costs (investment and O&M), the unit variable costs and the production duration (in hours per year) or plant load factor.

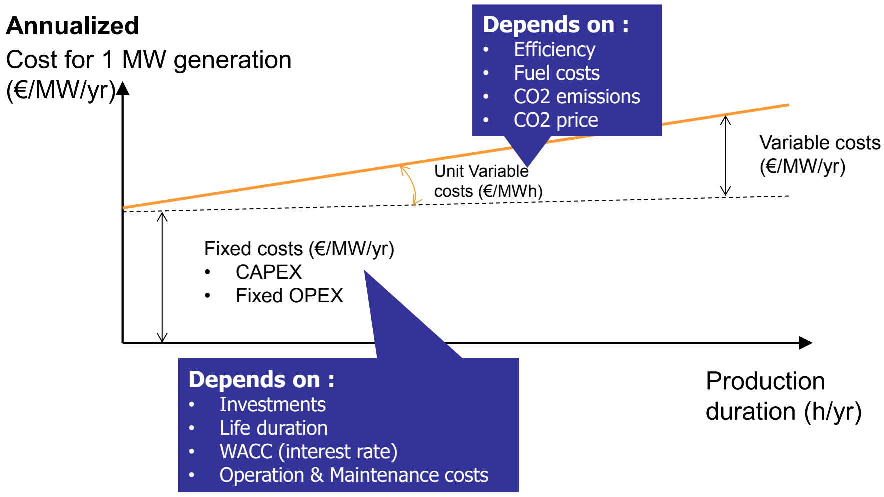


Figure 7-2 Total annual cost of a power plant as linear function of time.

For “run-of-river” power plants, based on renewables sources such as hydro, wind or solar, the variable cost are assumed to be zero (as no fuel costs are incurred and no CO2 emissions are released). The amount of produced energy per time step is not modelled, but is imposed by the availability of primary resource (i.e river flow, wind, sun) depending on the location and the scenario. The capacity factor for a given technology and a given location is the ratio of produced energy per time step and the maximum theoretical amount of energy that would be produced in ideal conditions.

7.2 Sensitivity analysis

As mentioned in the introduction, the scope of the feasibility is limited to one scenario. However, the study performed different sensitivity analyses in order to assess the impact of certain parameters.

Table 7-1 introduces the different case studies and sensitivities. There are two reference cases, several sensitivity analyses, and two more theoretical set-ups.

• **Reference cases** – Isolated zones with no interconnections – Reference case with interconnections • **Sensitivity studies** – Lower cost of interconnection between North Africa and Europe – Interconnection between UPS and North America made impossible – Sensitivity to higher costs of interconnections – Modification of wind capacity factors in Central Asia and North East Asia – Sensitivity to losses in the interconnections – Sensitivity to daily or seasonal storage possibilities	**Imposed production techs:** • following WEC scenarios: nuclear, coal with CCS, biomass, hydro • Wind and solar PV as in 2017 **Sized production techs, together with interconnections** • Gas technologies (CCGT with or without CCS, OCGT) • New wind and solar PV
• **More theoretical cases** – Only production allowed : solar photovoltaic and wind – Only production allowed: solar photovoltaic	

Table 7-1 The different study cases for the sensitivity analysis.

For the reference and sensitivity cases, not all generation technologies are optimized together with the interconnection capacity.

- The installed capacities of nuclear, coal with CCS, hydro and biomass power plants are taken into account in the calculation of the total cost of the system via their fixed and variable cost of operation. However, these technologies are not optimized, but imposed to yield the corresponding production volumes as given in the “Unfinished Symphony” scenario [1].

- The generation technologies subject to the optimization problem are gas technologies (CCGT with or without CCS, OCGT) and new deployments of wind and solar PV.

These are the generation technologies that are optimized alone in the first reference case which corresponds to isolated zones without interconnections. Subsequently, they are optimized *together with the interconnections* in the reference case with interconnections and the sensitivity case studies.

The sensitivity studies analyse the impact of various parameters (e.g., the costs of some or all interconnections, the impossibility of building one interconnection, the capacity factors, the resistive losses in interconnections or the existence of storage possibilities) on the total system cost.

The (even) more theoretical cases consider that the only production technologies available are wind and solar PV, and analyse the possibility to address the global electricity demand solely with these non-dispatchable technologies and interconnection capacities to transport power across macro-regions.

8. Results

8.1 Reference cases

8.1.1 Isolated zones

In order to accurately capture the benefits associated with building the interregional interconnections of the system, we start by optimizing the 13 individual regions independently, with no interconnection capacity available between them.

Figure 8-1 displays the generation share in TWh of each available technology for all the 13 regions considered in this study. The surface of each circle is proportional to the year-round electricity demand of the corresponding region.

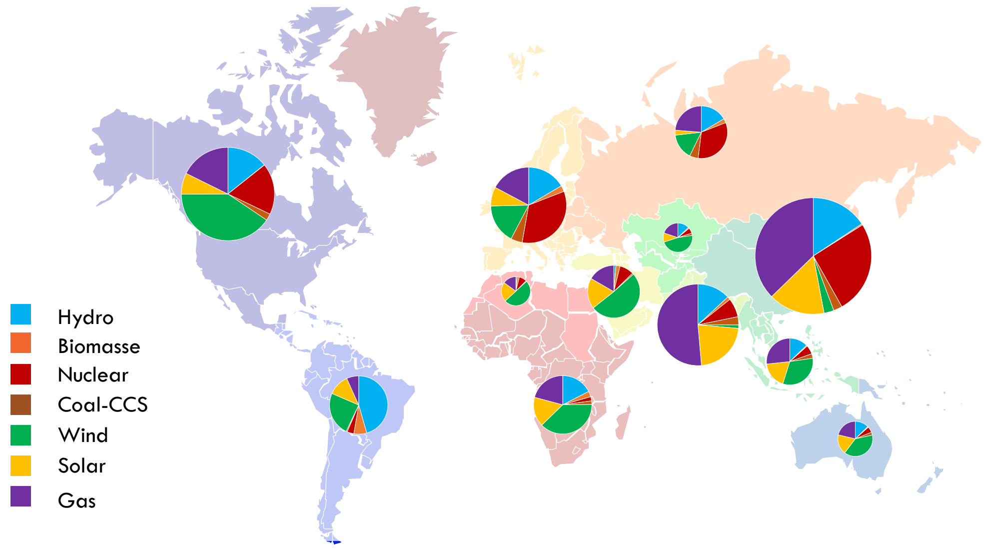


Figure 8-1: The share of each technology production for the 13 regions

Figure 8-2 displays the installed capacities of the optimized generation technologies (i.e wind, solar PV, and gas-fired generation) in GW for each of the 13 regions.

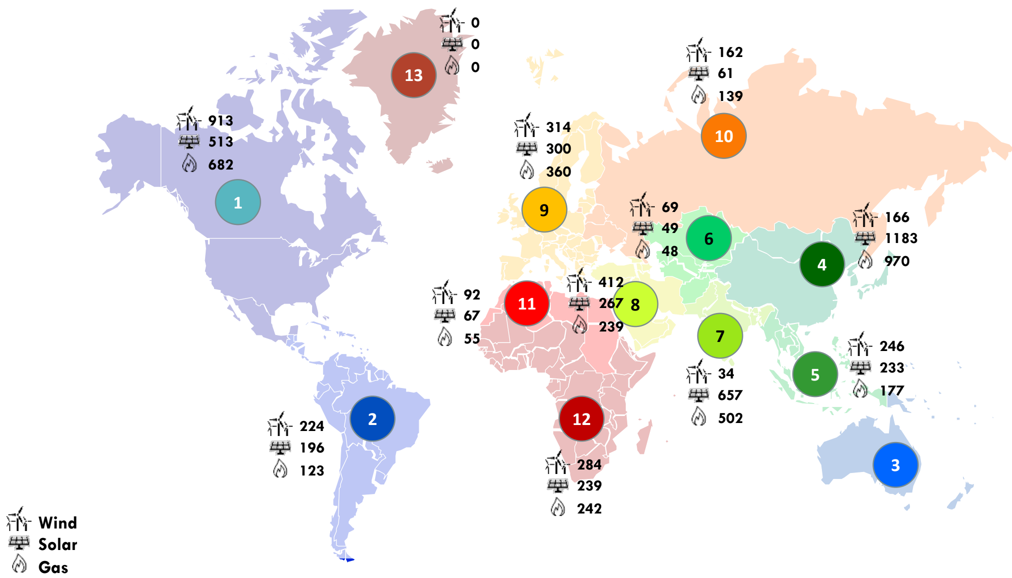


Figure 8-2: The installed capacities in GW for each region, for wind, solar and gas

To satisfy the worldwide annual electricity load of 39 850 TWh, the correspondin total installed capacity amounts to almost 13 500 GW. Figure 8-3 shows the share of each generation technology in terms of installed capacities (left) and electricity generation (right).

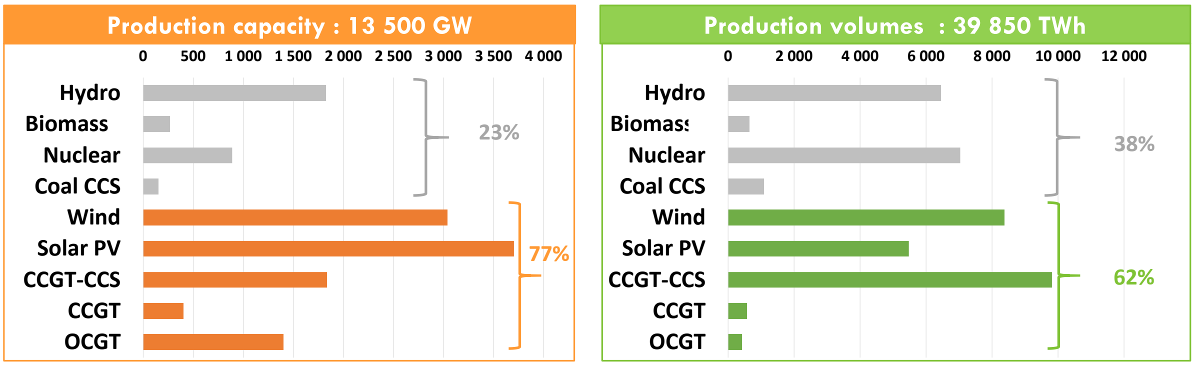


Figure 8-3: The share of each production technology, capacities and volumes – reference case

It can be seen that the optimized generation technologies represent 77% of the total installed capacities, but only 62% of the total electricity production. On the contrary the imposed technologies represent 23% of the capacities but close to 38% of the total generation. This can be explained by the fact that imposed technologies such as nuclear or coal with CCS are baseload technologies with an inherent higher capacity factor than renewable or gas-based technologies that either depend on weather conditions, or are used as peak plants.

Figure 8-4 shows the repartition of the total annual 2 150 billion euros (G€) cost associated with the aforementioned electricity mix. It shows the imposed technologies accounting for 41% of the total cost, while the optimized part of the system is corresponding with the remaining 59%.

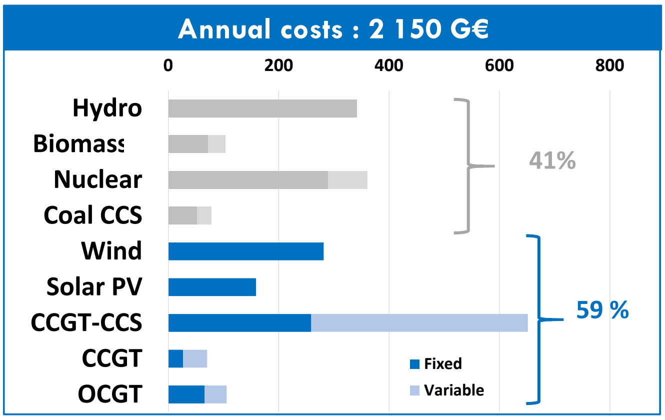


Figure 8-4: The repartition of the annual cost, reference case

It can also be seen that most of this cost is associated with fixed expenses, the variable cost share representing little less than 30% of the total cost. Thus the electricity cost per MWh rounds up to 54 €/MWh. The RES share (i.e hydro, biomass, wind and solar PV) of this generation mix is 53%. The estimated CO2 emissions are 850 million tons per year (Mt/y_r).

8.1.2 Reference case with interconnections

In this particular case, wind, solar PV, and gas-fired generation technologies are optimized together with the interconnections capacities between regions. Nuclear, coal with CCS, biomass and hydro production capacities are kept fixed according to the previous case. The optimization procedure is seeking for a balance between the costs of the interconnectors, and the benefits of mutualizing the load curves across different zones and providing access to renewable energy resource rich locations. Figure 8-5 displays the optimized generation and interconnection capacities in GW. The figures in brackets (that is, [ ]) shows the annuity associated with each of the interconnections in billion euros (G€).

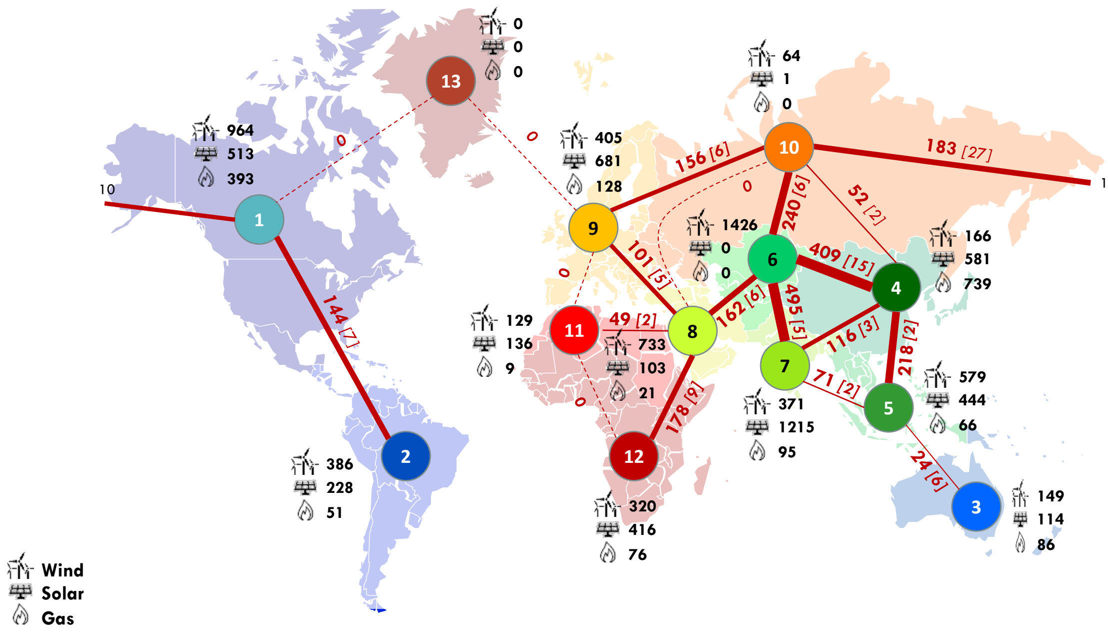


Figure 8-5: The optimized capacities (GW) for generation and interconnections

One noticeable result of this run is the development of large scale capacity interconnection around Central Asia (region 6) with 409 GW of ties to North-East Asia (region 4), 495 GW with South-East Asia (region 5), or 240 GW with Russia (region 10). This development is also associated with massive wind generation capacity in the same region, a fact explained in section 4-2 by very good capacity factors in the area. The 1426 GW wind deployments corresponding to the scenario is almost 20 times more the production capacity installed in the same region under “no interconnection” assumptions, far beyond the domestic needs of this region. Thus the interconnector capacities built are used to provide renewable (wind in this case) energy in all surrounding regions.

The most expensive interconnection capacity is developed between UPS and North America with 183 GW built for 27 G€/y_r. This interconnection is linking the Euroasian continent to the Americas and has a bi-directional use. As illustrated in Figure 8-6, the main driver for the use of this interconnection is the residual production in North America (i.e. total production – total load): when there is an excess of production in North America, the interconnection is used to export it to Asia and Europe through UPS region; on the opposite, when there is a lack of production in North America negative on Figure 8-7, mainly in summer due to cooling, the interconnection is used from UPS region to North America, including also wind generation in Central Asia (region 6).

The high degree of interconnectivity in Asia allows for a redistribution of regional electricity generation capacities. In this regards, less generation capacity is observed in North-East Asia (region 4) compared to the previous “isolated” case, while more capacity is installed in Central Asia (zone 6), or South-East and South Asia (regions 5 and 7) compared to the initial case, in an attempt to profit from better capacity factors in adjacent regions.

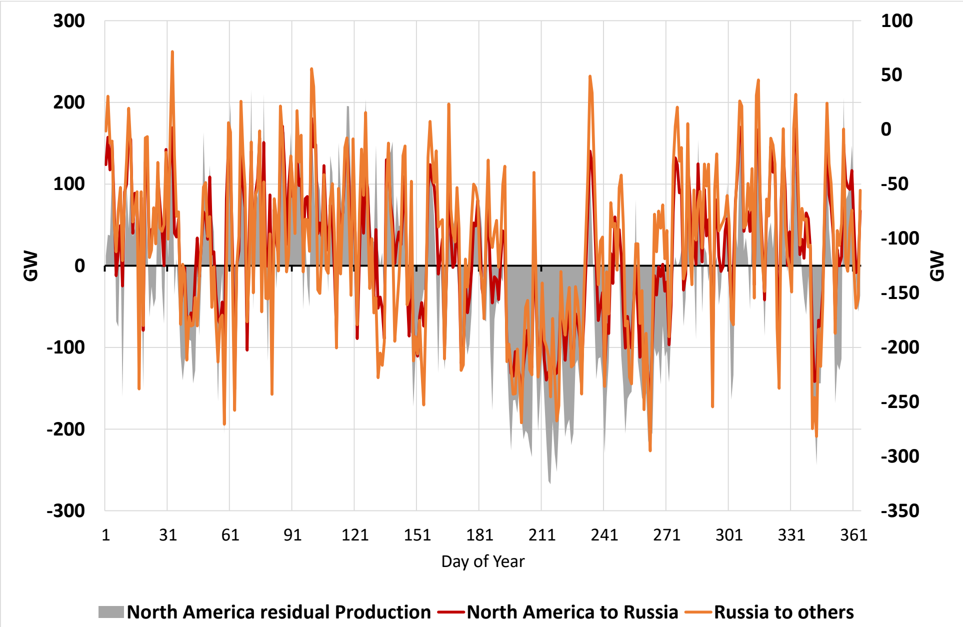


Figure 8-6: Daily average power from 1st January (day 1) to 31st December (day 365)

Some interconnections possibilities are not used at all: Examples of such cases are the North Atlantic to Europe or North Atlantic to North America interconnections; the North Africa to Europe link; between the North Africa and the rest of Africa tie. This is mainly due to an effect of the cost hypotheses made, with the aforementioned route having cheaper alternatives ready to serve the same purpose.

- According to our hypothesis, the cost of the route between UPS and North America is 150 G€/yr. The alternative route connecting the Euroasia continent to the Americas through Greenland costs 337 G€/yr, more than twice the cost of the former. Despite the possibility of very good wind capacity factors in Greenland, this route is not built. Later on, the sensitivity of these results to the impossibility of direct routing from UPS to North America will be discussed in detail.
- The cost of the direct North Africa to Europe link is almost the same (86 G€/yr, average of three different routes) with the same one going through Middle-East (North Africa – Middle East 36 G€/yr + Middle East – Europe 51 G€/yr = 87 G€/yr). Yet as the Middle East region plays a critical role as a regional hub (connected to North Africa, South Asia, and especially Central Asia), this route brings higher benefits. The sensitivity of these results to the cost hypothesis of the direct route between North-Africa and Europe will be investigated in a future sub-section.
- For the same economic reasons, the route through Middle-East is preferred to connect Africa (region 12) to North Africa (region 11).

At a global level, almost 2 600 GW of interconnection capacity is developed, representing 17% of the total generation deployments (around 15 000 GW), for a cost of 104 G€/yr. As illustrated in Figure 8-7, these interconnections allow for a massive development of V-RES production (mostly wind) that is replacing gas-based generation (mostly CCGT with CCS). The losses in the interconnectors lead to an increase of only 1% of production (440 TWh/yr).

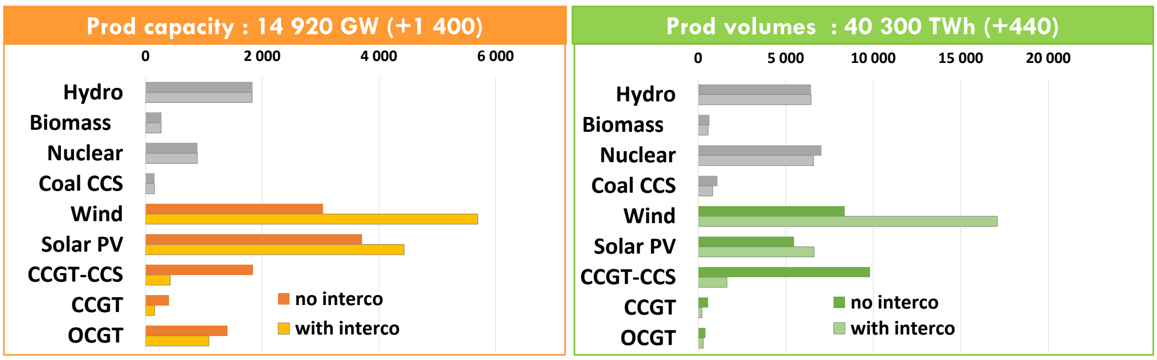


Figure 8-7: The share of each production technology, capacities and volumes – reference case with interconnections.

The replacement of gas-fired production capacity by wind and solar PV lowers the global cost of the system. The total production costs are 330 G€/yr lower than in the base case as illustrated in Figure 8-8.

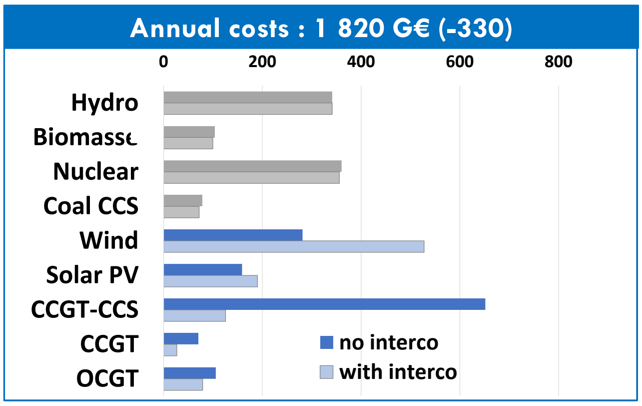


Figure 8-8: The repartition of the annual cost, reference case with interconnections

Thus the investment in the interconnections under the current cost assumptions (104 G€/yr) is fully covered with a global gain of 226 G€/yr representing more than 10% of the total cost associated with the base case.

The total electricity cost decreases from 54 €/MWh to 48 €/MWh. As gas generation is replaced by wind and solar PV, the RES share increases from 53% to 76% while the emissions are curbed from 850 to 343 Mt/yr.

8.2 Sensitivity analysis

In this section, the sensitivity of the previous results with respect to a set of parameters have been analyzed, through different variants:

- Lower cost of interconnection between North-Africa and Europe.
- Interconnection between Russia and North America made impossible,
- Higher costs of interconnections,
- Modification of the wind capacity factors in Central Asia and North East Asia,
- Sensitivity to the losses in the interconnections,
- Daily or seasonal storage possibilities.

The results of these sensitivity studies are presented in the following sub-chapters.

8.2.1 Lower cost of interconnection between North-Africa and Europe

As mentioned in section 8-1, the interconnection between Europe and North Africa is initially not built. At a first sight, this is due to the fact that the cost of the direct undersea route between the two regions, which is very close (86 M€/GW/yr, average of three different routes) to the cost of the alternative route through Middle-East (North Africa – Middle East - Europe = 87 M€/GW/yr). Yet the role of the Middle East region as a transmission and generation hub within this model brings a better overall benefit to the system.

The purpose of this sensitivity study is to analyze the consequences of reducing the cost of the interconnection between North-Africa and Europe, instead of taking the average cost of three possible different connection paths (86 M€/GW/yr), the cost of the cheapest route (the one passing through the Gibraltar strait 41 M€/GW/yr is considered. Figure 8-9 shows the production and interconnection capacities corresponding to this hypothesis.

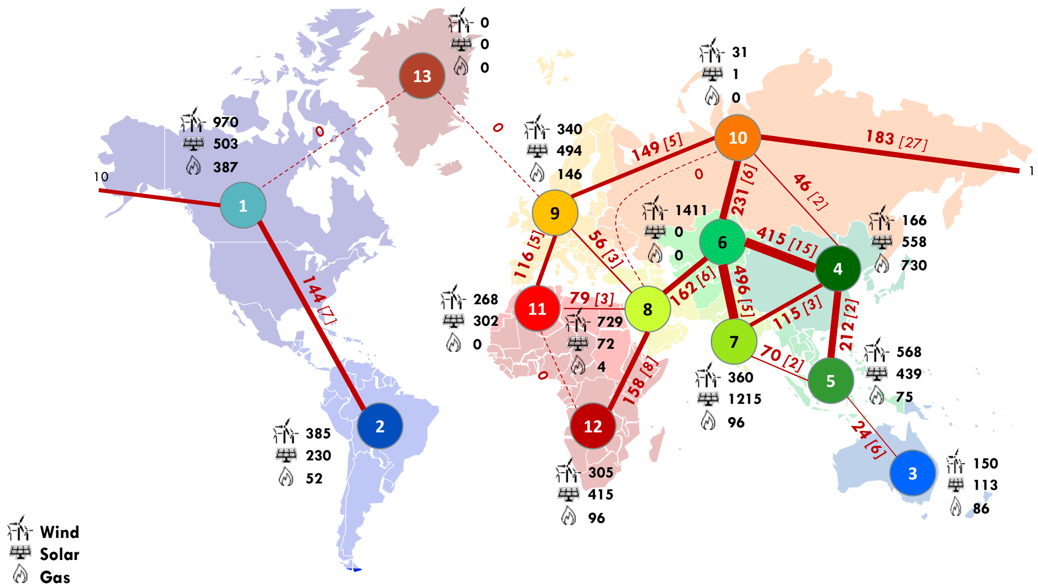


Figure 8-9: The optimized capacities – low cost of interconnection between North-Africa and Europe

In this case, the direct route between North Africa and Europe is built (116 GW). Compared to the reference case presented in section 8.1.2, the routes between the Middle East and Europe or Africa (region 12) are reduced in size, while the route linking the Middle East to North Africa is reinforced (+30 GW). The global interconnection capacity increases (+64 GW) for a slight increase of the interconnections cost (+3 G€/yr).

On the production side, the global electricity volumes are almost unchanged, but the location of wind and solar productions are affected. Asprobably expected, V-RES capacity is reduced in Europe and increased in North Africa. As a result the overall costs decrease (-5 G€/yr).

The total system costs, the RES share and the CO2 emissions are almost unchanged compared to the reference case.

As the previous sensitivity study (i.e. UPS to North America not possible), this analysis illustrates that the optimal system has to be understood as the least cost choice within the feasible domain. In the reference case, no interconnection between North Africa and Europe translates into existence of better, meaning cheaper, solutions, given the set of assumptions considered.

8.2.2 Interconnection between Russia and North America made impossible

As mentioned in section for the reference case, the link between Europe and North America through the North Atlantic is never built despite the availability of very good wind capacity factors in the latter region. In a first analysis, this is due to a less expensive alternative route from UPS to North America, that enables an indirect connection of the Euroasian and American continents.

The purpose of this sensitivity study is to assess the consequences of making the UPS-North America interconnection not possible for reasons beyond any technical or economic justification. Figure 8.10 shows the generation and interconnection capacities resulting from this hypothesis.

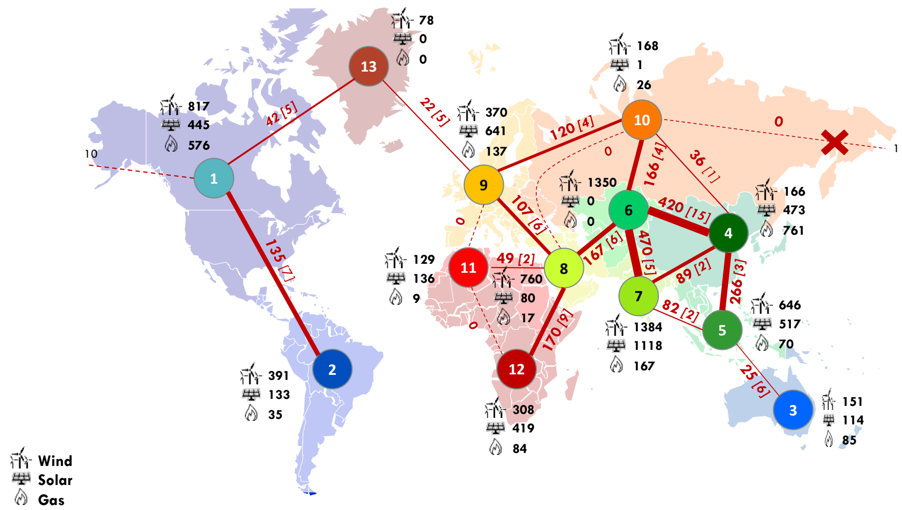


Figure 8-10: The optimized capacities assuming no direct tie between UPS and North America

Making the interconnection between UPS and North America impossible to build leads to the development of the North Atlantic corridor. However, compared to the refrence case with transmission ties between regions (section 8.1.2), the associated transmission capacity is limited due to the higher costs (64 GW vs 183 GW). The overall interconnection capacities are smaller (-231 GW), for a gain of 21 G€/yr. As the route between Asia and North America through UPS is not possible, the interconnections between Asia and UPS decrease. This run also reduces the V-RES production levels in Asia and North America, while partly replacing them with wind deployments in UPS and the North Atlantic, but also with gas-fired generation in North America.

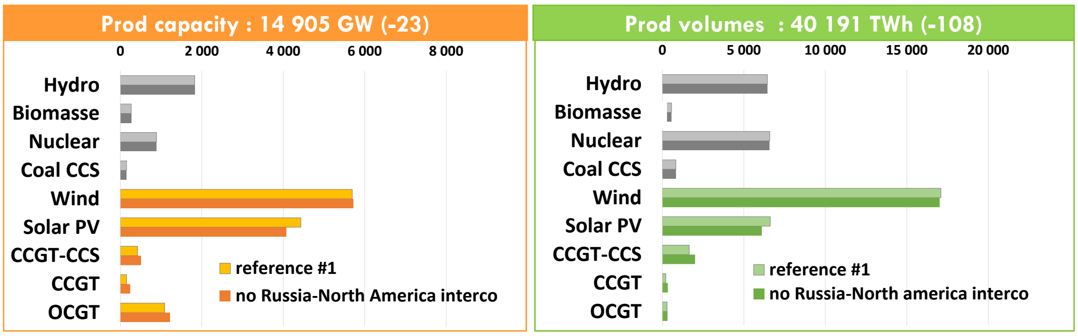


Figure 8-11: The share of each production technology, capacities and volumes – with seasonal storage case.

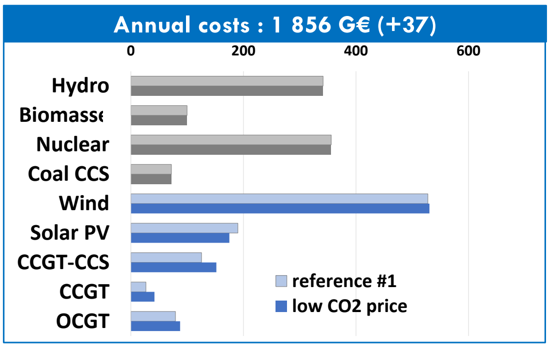


Figure 8-12: The repartition of the annual cost, seasonal storage case

Compared with the same reference case, the annual production costs are slightly increased (+37 G€/yr).

The total system cost increases marginally (+1 €/MWh), while the RES share decreases a -1% and the CO2 emissions are higher (+70 Mt/yr).

8.2.3 Sensitivity to a higher costs of interconnection

As the optimization process seeks for a balance between production and interconnection costs, we expect the results to be sensitive to their respective costs. We therefore go on with assessing the results of the same model with higher specific costs for interconnection capacity. Figure 8.13 figure displays the electricity production and interconnection capacities obtained.

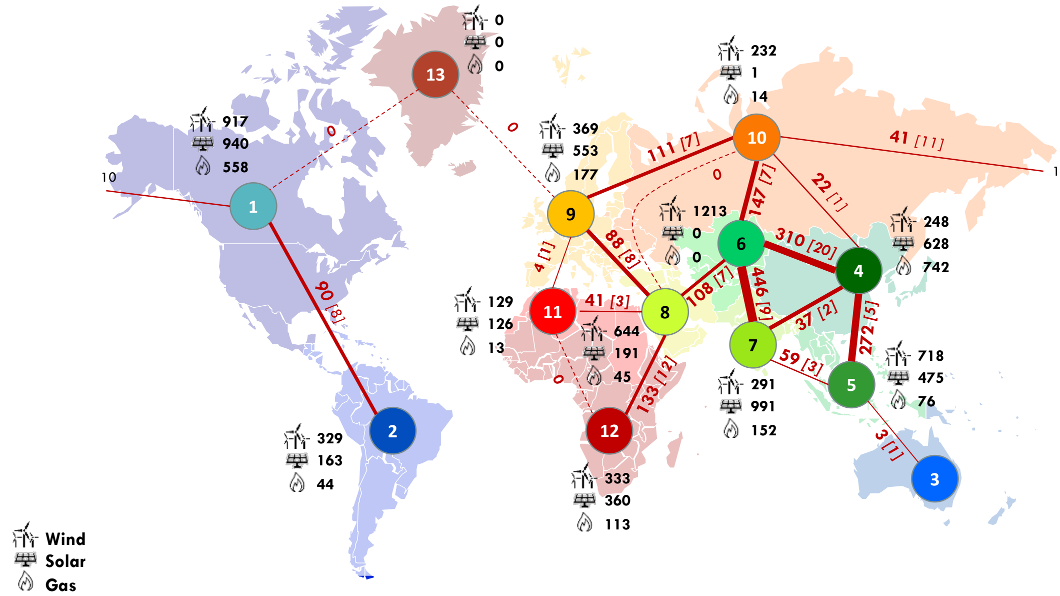


Figure 8-13: The optimized capacities with higher costs of interconnections

As expected, compared to the case including intercontinental interconnections (section 8.1.2), the overall interconnection capacity installed decreases substantially, from 2600 to 1911 GW (-27%) for about the same cost (106 G€/yr). Almost all interconnections are concerned, with a bias towards the longer routes. For example, the interconnection capacity between UPS and North America drops from 183 to 40 GW (-78%).

On the generation side the main effect is to relocating generation assets within the demand regions (e.g North-East Asia, North America and UPS) and lower V-RES capacities, as these technologies are replaced by gas-based generation. The production cost increases by 60 G€/yr, compared to the same reference.

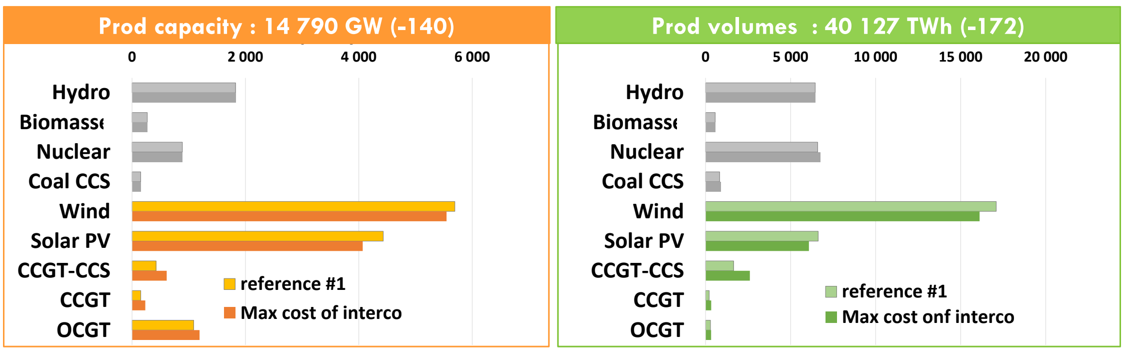


Figure 8-14: The share of each production technology, capacities and volumes – higher costs of interconnections case.

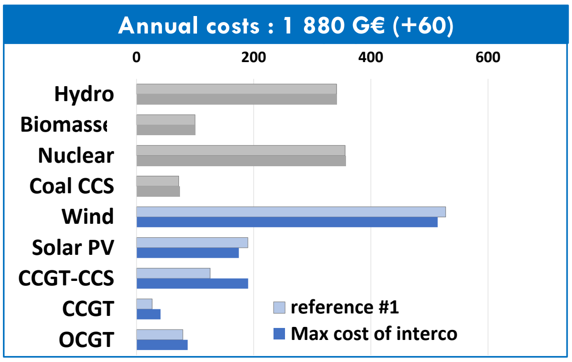


Figure 8-15: The repartition of the annual cost, higher costs of interconnections case

The results suggest a compromise situation between the reference case with interconnection (section 8.1.2) and the initial scenario based on "isolated" (section 8.1.1) with the latter potentially associated with infinite costs for interconnection capacity.

The total system cost is slightly higher compared to the case including intercontinental interconnection (from 48 to 50 €/MWh). As the production capacity is deployed more locally, more gas-based generation is required therefore the CO2 emission levels (+100 Mt/yr) as well as the RES share (-3%) are impacted.

8.2.4 Modification of the wind capacity factors in Central Asia and North East Asia

As explained earlier, the very good wind capacity factors in Central Asia (41% yearly average) explains the development of very large interconnection and wind generation capacities in this region. Figure 8.16 compares the wind capacity factors recorded in 2015 [86]. This figure shows that the modelled capacity factors are slightly higher than the recorded ones, a fact which can be explained via (i) the expected technological progress in wind turbine manufacturing and (ii) the potential access to, high-yield production sites which are currently not in use. That may be the case for Central Asia for which the modelled capacity factor of 40 % is considerably higher than the 2015 values (31%) measured for a rather small generation capacity (i.e 83 MW). The only region for which the prospective capacity factor is lower than the 2015 values is North East Asia (20% vs 23%).

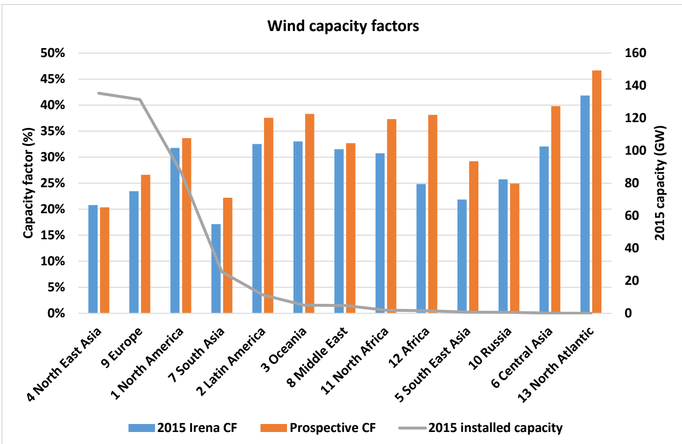


Figure 8-16: The comparison of the prospective wind capacity factors

It order to assess the sensitivity of the results to this set of parameters, we propose two adjustments:

- The capacity factor for Central Asia is decreased from 40% to 31%.
- The capacity factor for East Asia is increased from 42% to 23%.

The alteration of the hourly capacity factors apply for every time step. Figure 8.17 shows the installed capacities resulting from these alterations:

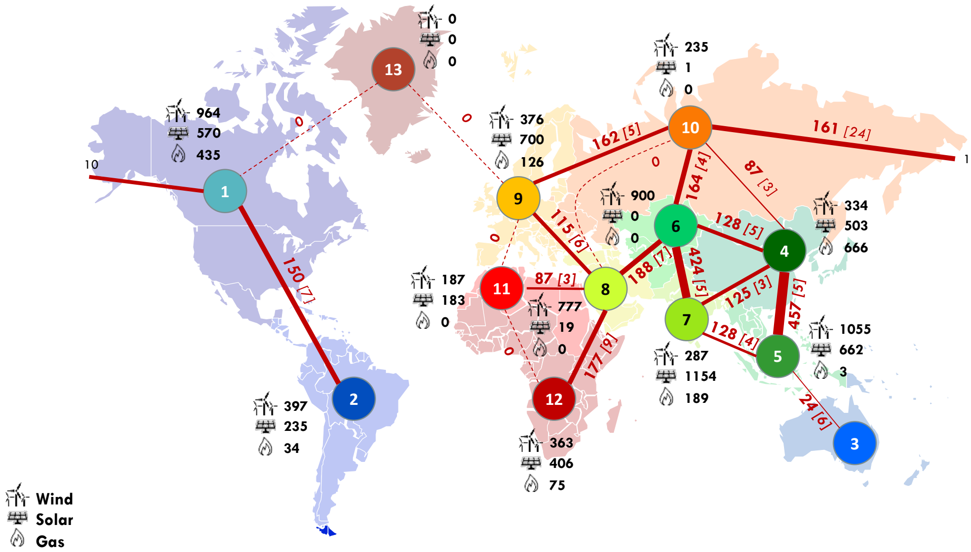


Figure 8-17: The optimized capacities with modification of the wind capacity factors in Central Asia and North East Asia

As expected, a lower wind capacity factor in Central Asia decreases the wind generation capacity in this region by -526 GW. This capacity is mainly replaced by increased wind production capacities in South East Asia (region 5), North East Asia (region 4) and UPS (region 10), and also superior solar capacities in South East Asia (region 5). Another result of this sensitivity is the lower interconnection capacity between Central Asia (region 6) and North East Asia (region 4), replaced by an increased interconnection capacity between South East Asia (region 5) and East Asia (region 4).

Compared to the case including intercontinental interconnection capacities (Section 8.1.2), the overall numbers of the global system are similar. As the wind capacity factor in Central Asia is less favorable, it increases slightly the cost of electricity by less than 1 €/MWh.

8.2.5 Sensitivity to the losses in the interconnections

In the reference case including interconnection capacities (see section 8.1.2), we take into account proportional losses in the interconnections. For DC ties, 1% losses are assumed in the inverters, while 0.15%/100 km and 0.5%/100 km loss factor is associated with OHL and USC, respectively. For AC interconnections, 0.15%/100 km loss factor is assumed.

Depending on the length and technology of each interconnection, this leads to losses from about 3% to more than 15% of the underlying flows, with the upper bound corresponding to the interconnection between UPS and North America. As mentioned earlier, these losses increase the necessary global production by close to 1% (440 TWh/yr).

A simulation for which the losses are assumed to be zero is performed, in order to analyze their influence on the optimal decision-making. In this context, the very long routes, or the ones with associated load factors, are developed to even higher capacities compared to the results shown in section 8.1.2. In this regard, the capacity between UPS and North America is increased from 183 to 213 GW, while the capacity between Central Asia and North East Asia is increased from 409 to 441 GW.

As this balances the efficiency of some distant production, few interconnection capacities are lowered. For example the capacity of the interconnection between North East Asia and South East Asia is reduced by 43 GW.

On the global level, and compared to the case including intercontinental interconnection capacities (section 8.1.2), the total amount of interconnection capacities is increased by 90 GW (about 3% of total capacity) for a cost that increases with 9 G€/yr (+9% as it affects the longer and most costly routes). The gain in generation capacity costs amounts to 24 G€/yr, which leads to a marginal global gain of 0.4 €/MWh.

The RES share and CO2 emissions levels are almost unchanged.

8.2.6 Daily or seasonal storage possibilities

The previous cases do not take into account storage possibilities. As storage is often presented as a competitor of grids, the following cases studies analyze the influence of storage on the results. Two kinds of storages have been modelled: daily or seasonal. For daily storage, the sensitivity of results to the power of the storage has been analyzed.

Daily storage

The daily storage considered here is not addressed with a specific technology: it could be made with batteries, or with demand side management. Therefore no cost assumption was made for this storage, assumed to be "for free". As we add free flexibility in the system, we are expecting lower costs of the global system. We represented the daily storage as a part of the daily demand that could be displaced within the day, under some constraints:

- Daily volume : 10% of the daily load in each of the 13 regions.
- "Power" limit on the hourly flow of the storage:
    - In the case of "low power variant", 20% of the daily volume (i.e. 2% of the daily demand). In other words, charging/discharging the full energy of the day takes 5 hours.
    - In the case of "high power variant", 100% of the daily volume. In other words, charging/discharging the full energy of the day takes only 1 hour.
- Efficiency of the storage: 90%.

The low power storage variant does not change significantly the results. Therefore, we present only the case of "high power variant" in the following. However it is interesting to see that a 5 hour daily storage is not powerful enough to influence the need of interconnection in such a system. With a one hour daily storage (10% of the daily load can be displaced on the same one-hour time step), the needs for interconnection and production capacities are modified as represented in Figure 8.18.

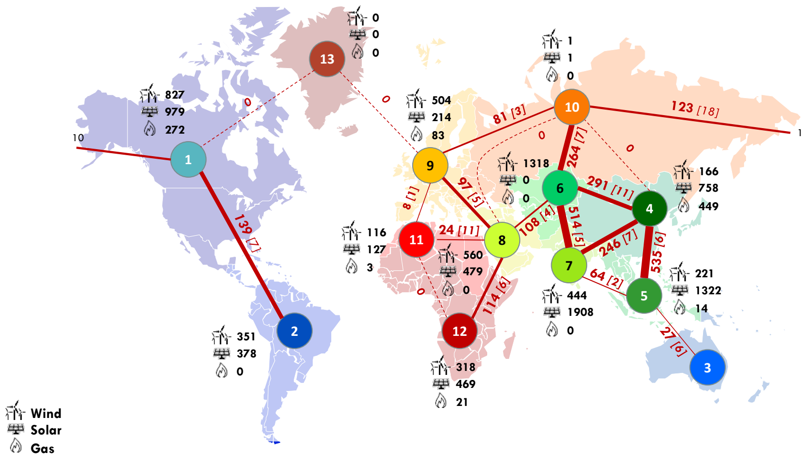


Figure 8-18: The optimized capacities with daily storage possibilities

Providing free daily flexibility is favorable to solar production. Therefore much more solar PV is installed in regions with good solar capacity factors. North and Latin America, North East Asia, South East Asia and Middle East. At a global level, the solar PV capacity increases from 4430 to 6800 GW (+53%). This solar production replaces a part of wind production and gas production (mainly CCGT with CCS on the energy production point of view, but also OCGT production capacities).

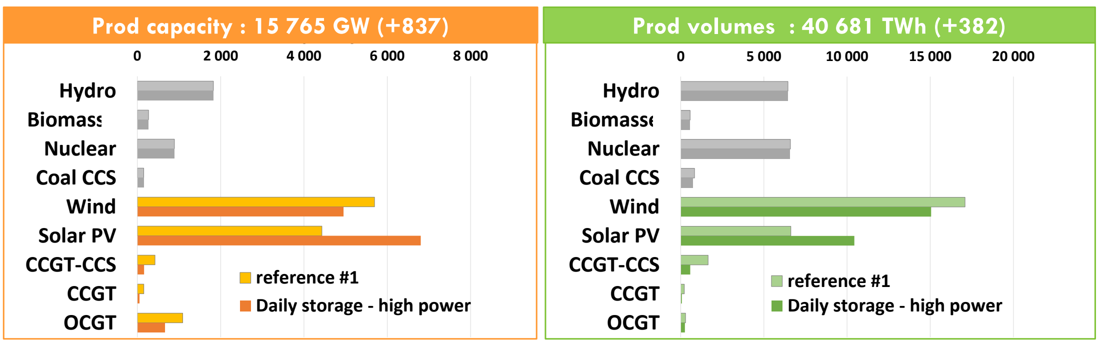


Figure 8-19: The share of each production technology, capacities and volumes – with daily storage possibilities.

The loss in the storage leads to an additional 1% energy production (3825 TWh/yr).

As production is more localized in regions with good solar capacity factors, some interconnection capacities are lowered, especially when there are linked with distant wind productions. This is the case for the interconnections between Central Asia and North East Asia (-118 GW) and the interconnections between UPS and Europe (-75 GW), North America (-60 GW) or North East Asia (-52 GW, no more need of this interconnection).

However the interconnection capacities are much increased between North East Asia and South Asia (+130 GW) and South Asia (+317 GW). These are relatively short interconnections, allowing for the big consumption zone of North East Asia to get more benefits of favored solar production in South and South East Asia, with good solar capacity factors.

Globally the interconnection capacities remain almost the same (2632 GW) for a lower cost (from 104 to 88 G€/yr) as long distance interconnection capacities are replaced by shorter ones. The annual production costs also get lower, as illustrated in Figure 8.20, due to daily flexibility on the load curve.

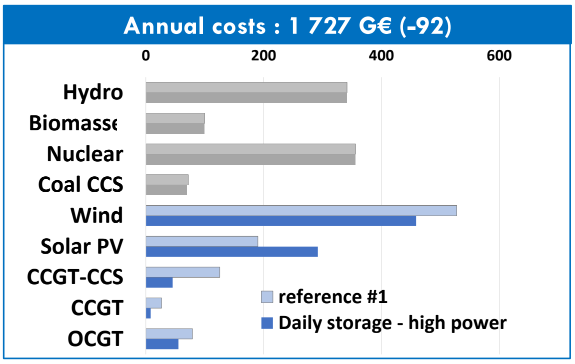


Figure 8-20: The repartition of the annual cost, daily storage possibilities case

Globally, the total cost of the system gets lower to 46 €/MWh (-2 €/MWh). This gain should be compared with the actual cost of providing such a level of daily flexibility, assumed to be free in this analysis. As solar production replaces not only wind but also gas production, the RES share is increased (+4%, going to 80%) and the CO2 emissions are lowered (-121 Mt/yr).

For comparison, the low power daily storage (5 h instead of 1 h for the same energy capacity) leads, compared to the reference case, to an additional development of solar power about 10 times lower (+250 GW instead of +2370 GW). Thus considering a potential “competition” between daily storage and development of interconnexion, one must remind that the power of the storage is a very important parameter.

Seasonal storage

The possibility of a seasonal storage was also considered, linked to hydraulic capacities (in the previous results, all hydraulic resources are assumed as run-of-river resources). The volume of seasonal storage considered is 1/3 of the annual hydro volume for each zone. The management of this flexibility has been considered in a very simplified way, to flatten as much as possible the residual demand of each zone (load – run-of-river productions) by progressively affecting the storage volume: the annual storage volume is distributed monthly according to the monthly residual demand, each monthly volume is distributed weekly according to the weekly residual demand and finally each weekly volume is distributed daily and hourly. This procedure is of course very simplified compared to what would actually done with a proper management of hydraulic reservoirs (deterministic view, no influences of the management between zones,…). As this is a very simplistic representation, it must thus be taken only for an indication of the role of seasonal storage. As for the daily storage, it is assumed for free.

At a global level, the annual seasonal storage is 2 150 TWh, representing about 5% of the annual electricity consumption. By flattening the residual demand, this allows to increase the wind and solar productions (about + 3% for both technologies, for a total of +680 TWh), and reduce gas productions of the same amount.

At a global level, the total cost of the system gets a little bit lower (-1 €/MWh), the RES share increases (+ 2%) and the CO2 emissions are lowered (-73 Mt/yr).

8.3 solar and wind only systems

The former cases allowed for the existence of conventional production technologies, such as nuclear, coal or gas with CCS, in the resulting electricity mix. As more theoretical cases, the working group decided to analyze to assess the transmission requirements associated with a global power system based on V-RES generation only. For a first run, solar only production is assumed, while a second case looks into a system built solely from solar PV, and wind converters. The main goal for such a case study is to stress one of the main motivations of this work, that is the degree of V-RES complementarity at a global scale.

8.3.1 Solar only production system

Figure 8.21 gives the interconnection and generation production capacities for a solar PV only global system.

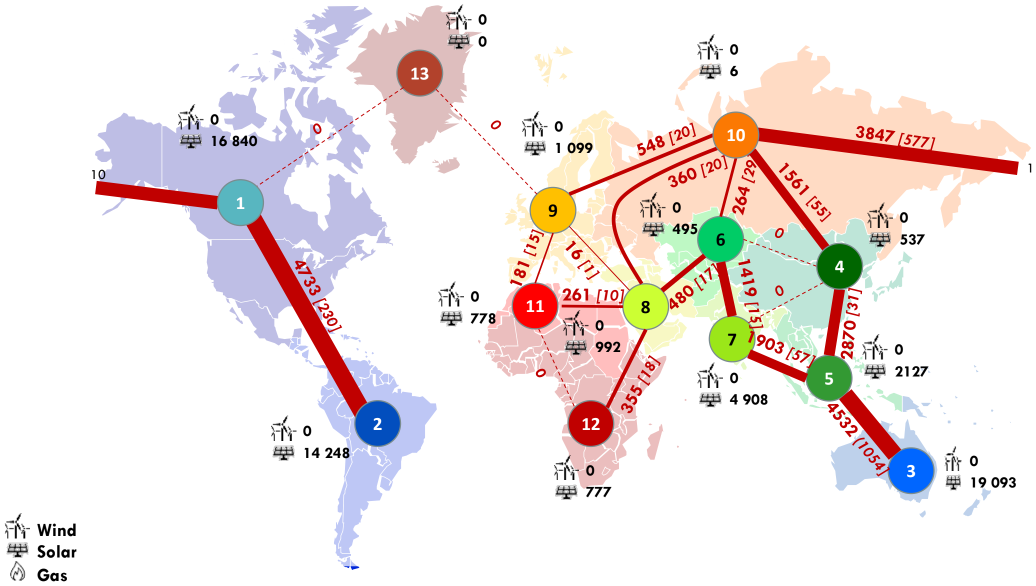


Figure 8-21: The optimized capacities – only solar production case

A total installed capacity of 62 000 GW is deployed worldwide (more than four times the capacities of reference case) for a cost of 2 650 G€/yr. The largest capacities are installed in South East Asia (21127 GW), Oceania (19093 GW), North America (16840 GW) and Latin America (14840 GW). The choice of these regions revalse a preference towards superior solar resource quality and also for both seasonal and daily complentarity of production profiles. 24000 GW of interconnections capacity is installed worldwide for a cost of 2150 G€/yr. A significant share of the total interconnector capacity is deployed between Oceania and Latin America, through Asia, UPS, and North America. The connection of Europe with Africa can be seen as secondary routes connected to this large corridor.

In this particular system, the interconnection deployment capacity represent 38% of the generation capacities (against 17% in the reference case), while its associated costs represents 45% of the total system cost (vs 5% in the reference case).

Despite the fact the production capacity being distributed worldwide to maximize the complementarity of different locations, a massive over-production and curtailment is necessary to minimize the volumes of energy not served. This is illustrated in Figure 8.22.

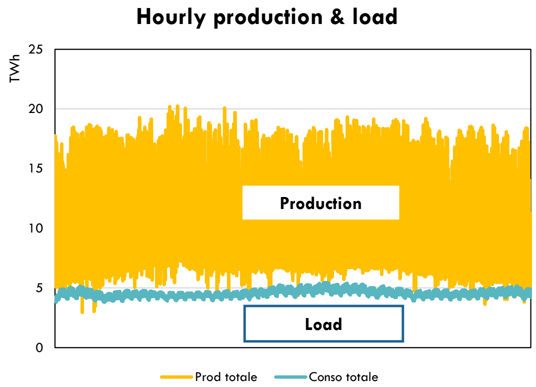


Figure 8-22: The hourly production by 2050, only solar case

This leads to 97000 TWh of electricity generation, including 57000 TWh of curtailment (52 000 TWh) and losses in the transmission lines (5000 TWh), required to satisfy a 40000 TWh demand.

The total system reaches 120 €/MWh (55% production, 45% interconnections) compared to 48 €/MWh associated with the refrence case with intercontinental interconnections (Section 8.1.2).

8.3.2 Solar and wind only production system

This time we propose a system in which solar PV, wind and interconnection capacities can be deployed (see Figure 8.23). Over compared to the previous case, we let the possibility to invest not only in solar but also in wind production.

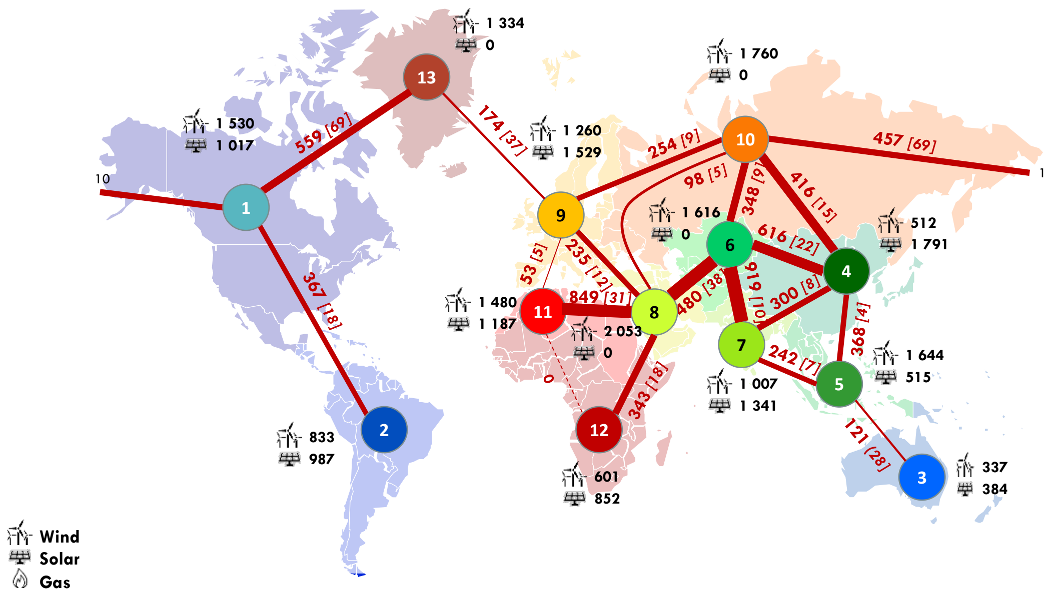


Figure 8-23: The optimized capacities – only solar and wind production case

Over 25800 GW of generation capacity are installed (62% for wind, 38% for solar), leading to an annual production of 61000 TWh (76% from wind, the remainder from solar PV).

The complementarity of wind and solar PV resources supports a decrease in generation installed capacities compared to solar only case yet. 16000 GW of wind and 10 000 GW of solar PV are still deployed for a cost of 1900 G€/yr. In addition, 7800 GW of interconnection capacity is installed worldwide for a cost of 415 G€/yr.

In such system, the interconnection capacities represent 30% on the overall generation installed capacity (against 17% in the reference case) and their costs represent 18% of the total system cost (against 5% in the reference case).

Once again, as illustrated in Figure 8.24, a massive over-production and subsequent curtailment is necessary to minimize the system-wide energy not served. In other words, 62000 TWh of electricity generation come along with 22000TWh of curtailment (21300 TWh) and losses (700 TWh), in order to meet a 40000 TWh load.

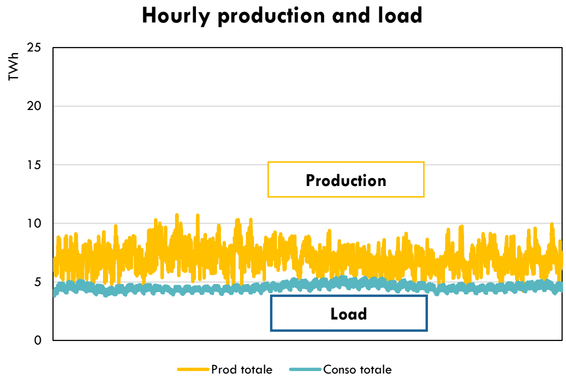


Figure 8-24: The hourly production by 2050, wind and solar case

The total system cost decreases sharply compared to the solar PV-only system reaching 58 €/MWh (82% production, 18% interconnections), compared to 48 €/MWh for the reference case with intercontinental interconnections and 54 €/MWh for the case associated with the base case.

9. Challenges

9.1 Social and environment issues

9.1.1 Towards social and environment acceptance of transmission system expansion

Under most legal and regulatory frameworks globally in use, transmission system expansion planning including line siting is a costly and time-consuming endeavor. Frequently, the realization of new intra- and interconnection commissioning is delayed due to slow and inefficient planning and permission processes [108]. Another important aspect is the improvement of social or political acceptance to network development or upgrades that are further analyzed within this chapter.

While during many decades infrastructure projects were considered as a main driver to spur socio-economic development, winds have changed with growing social opposition being nowadays regarded as a main barrier to electricity network deployment [109]. Decreasing public acceptance of large-scale electricity infrastructure projects was reported as a major hurdle to the expansion of the transmission system in Europe, Latin America [110] and the United States of America [108]. Some initiatives even managed to cancel transmission expansion projects [111].

Consequently, research has been directed towards the questions “What factors cause the success or failure of transmission line projects to engage with public stakeholders?” and “How can social and environmental concerns be overcome to improve public acceptance?”. Recent studies have explored both the motives of individuals to oppose transmission infrastructure development as well as the ingredients of reducing public objections [112, 113].

The work of [109] contains a 5 dimension framework of typical concerns towards transmission line development that should be addressed to increase the public acceptance of such projects (compare Figure 9.1). These can be grouped under “Need”, “Transparency”, “Benefit”, “Environment” and “Engagement”.

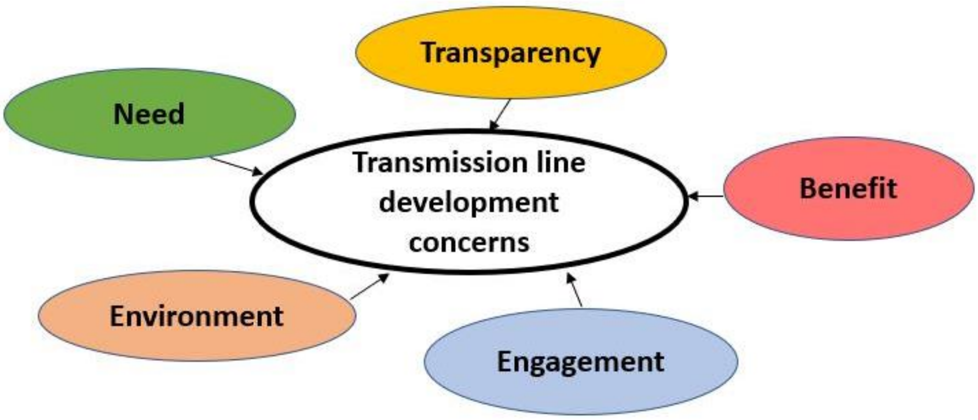


Figure 9-1: Concerns against transmission lines [109]

While the “Need” dimension points to a low public understanding of the need of the proposed infrastructure project and potential alternatives (other corridor routing, energy efficiency, etc.), “Transparency” embraces the public interest in the comprehensiveness of planning criteria, technology choice as well as the allocation of benefits or compensations.

“Engagement” on the other hand refers to commonly mentioned doubts on how network planners consider stakeholders feedback and integrate recommendations into the project’s decision process. Concerns grouped under “Environment” on the other hand point towards risks for human health such as noise from transmission lines, visibility effects, effects on biodiversity and electromagnetic frequencies (EMF). Finally, “Benefit” concerns subsume opposition resulting of the decrease in property value or other compromises a local community needs to make under the realization of a transmission line.

Those concerns can be amplified, among others, with the proximity of stakeholders to the planned transmission line, under the absence of sufficient technical or economic knowledge on the system and potential alternatives, miss-trust in the developer as well as the perceived land value and aesthetical considerations [113].

The table below provides concrete insights on how these concerns are typically formulated to project developers. Concerns were recorded during public meetings of project developers and private stakeholders within the frame of the European BESTGRID project [112].

Table 9-1: Common concerns towards transmission infrastructure development: The European case

Guiding Principle	Elia (Underground Cable)	Elia (Stevin Project)	TenneT	50Hertz
Needs	Unclear need as it is not clear if energy consumption in the region will be growing	Need of the project location and communication about the need of the project	Unclear need because of decentralized generation options	Need for transmission of electricity to Poland
Engagement	Optimum time for engagement, believe about impacts of participation	Early involvement of local authorities, guided process of engagement, feedback from local stakeholders on routing	Place of public information events, where everybody could pass by and not only already informed stakeholders	Information about who will be involved in discussions about the project
Transparency	Planned corridor, sources of electricity	Details of the project and how it will affect everyday life, criteria for decision making, clear information, trusted communication channels	Criteria of selecting priority corridor, sources of electricity	Planning procedures, source of electricity, EMFs
Environment	Impacts on human health	Noise from cooling systems and cables, need for independent SEA and EIA, coherent approach for several infrastructure projects	Visibility impacts, security of transmission system, impacts from EMFs	Impacts on environment, visibility impacts, impacts from EMFs
Benefits	Modernization of routes during construction period, possible benefits from the project for local communities	Fair compensation between inhabitants, clear rules of compensation, regulatory framework, compensation to environment	Distribution of burden and benefits between different communities and provinces	Compensation to land owners, compensation to environment

Addressing the above-mentioned concerns is fundamental to overcome large-scale transmission expansion projects such as the transition towards a globally interconnected electricity network. Efforts might be higher for a global grid endeavor as it was found that interconnectors tend to face stronger public opposition than domestic lines.

It was suggested that these effects occur as local communities might see those projects serving solely big power companies revenues and not the public interest [114].

The following section will show successful approaches to involve stakeholder groups and increase the mutual satisfaction between electricity infrastructure developers and the concerned public.

9.1.2 Best practices/ stakeholder engagement approaches

In the following subchapter, we will synthesize the most relevant aspects of social/environmental opposition to transmission line installations and potential ways to overcome public doubts. The following table (Table 9.2) shows reported opposition and potential solutions covering different world regions.

It is important to note, that although strong variability of public opposition towards infrastructure projects was reported among countries, still little of the causes why some population groups or societies tend to oppose more than others have been understood [111].

Table 9-2: Reported barriers to social acceptance regarding transmission system expansion around the world

	Europe	Latin America	United States of America
Reported opposition and reasons	**Opposition due to a lack of project alternatives presented to community** In-transparent siting and benefit allocation criteria Concerns about noise, environmental impact and EMF	**Strong opposition by land owners and environmental activists**	**Delay in project planning due to land negotiations and consumer resistance especially in areas with high population density**
Proposed solutions	**Increase trust in the developing entity** **Provide opportunity for stakeholders to negotiate compensations** **Sufficient provision of project-related information on system benefits**	**Identification of corridors of public interest that can be used for future expansion projects** Draft generalized siting and line routing criteria to foster transparency Provide educational offers with wide coverage	**Joint planning of several states to increase efficiency** Federal siting authority that can act as mediator Providing compensation packages that are acceptable for local communities
Sources	**(BESTGRID, 2015a), (Komendantova & Battaglini, 2016), (Cohen et al., 2016), (Perras, 2014)**	**(VALPUESTA, R.; ARANEDA, 2006), (Avila, 2004)**	**(Yang, 2009)**

The outcomes suggest that across all world regions, a close involvement of stakeholders, transparent planning processes and negotiable compensation schemes can facilitate the realization of large-scale transmission projects. However, there are no reports/ information social acceptance issues in Asia, Africa and Australia, which should be further investigated on.

This could be explained by strong positive connotation of infrastructure as mean to spur electrification and economic development as well as remarkable efforts to measure and address consumer satisfaction in these regions.

In the following, we will look at a typical transmission line planning process to identify a suitable time-span for stakeholder involvement.

The typical planning process of a transmission line on European ground is shown below (Figure 9.2). The figure shows that the planning process is typical divided into several stages. While the first step consists in the internal identification of investment needs (demand growth, connect renewables, market integration) at the TSO, the authorization phase exposes the project to external stakeholders. After passing environmental and planning related hurdles, the major part of the planning process concludes with the acquisition of land rights. Following a relatively short construction and commissioning period, the line comes into operation.

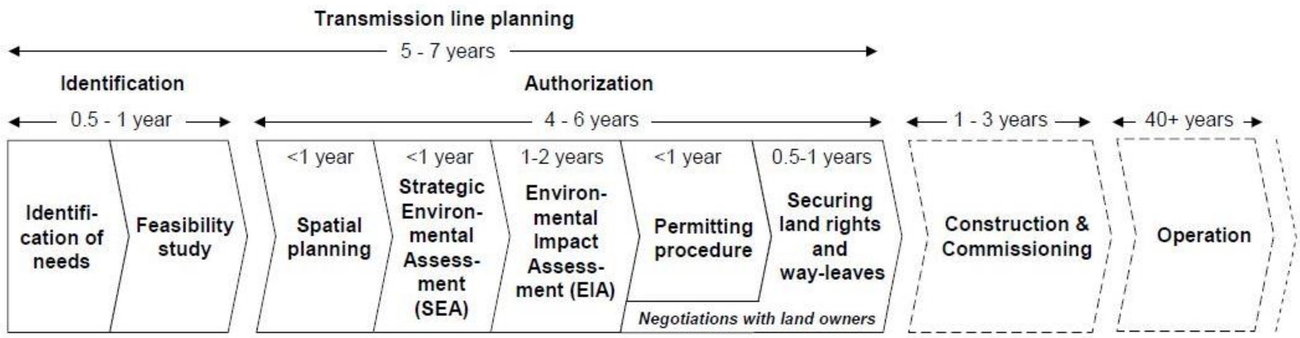


Figure 9-2: Typical transmission line commissioning process [113]

Given the nature of the planning process and outcomes on successful stakeholder engagement, it is appropriate to involve the public, environmental and social initiatives from the very beginning of the authorization process. As explained above, local resistance can be mitigated with early involvement of all affected stakeholder groups as well as the provision of transparent planning criteria and compensation packages that are tailored to the specific needs of the communities addressed.

9.1.3 Facilitating global transmission interconnection efforts:

We conclude this sub-hapter with two suggestions that attempt to overcome potential social/ environmental concerns of global interconnection efforts and thus decrease the chance of public opposition.

- A common drawback of the realization of power system interconnectors was seen in the absence of an adequate regulatory that facilitates the allocation of risks, costs and benefits among all stakeholders involved [109].

  When it comes to the realization of a globally interconnected power system, there is little chance to expect that a newly developed "world energy regulator" would facilitate spatial planning, cost allocation, stakeholder involvement tasks. However, one suggestion is that a newly developed or existing, independent institution would be determined that plays that role and supervise the planning of the global power system interconnection (e.g. the International Confederation of Energy Regulators – ICER).

  Such actor could enter a formal relation with the planning consortium (assumingly a transnational group of TSOs) and on the other side, establish a process that guarantees the appropriate involvement of local and global stakeholder groups affected by such a global grid (environmental associations, social initiatives, consumer protection agencies).

- As another relevant outcome of this literature review, we found that the access to complete information and transparency of the developers were recognized as important milestones towards public involvement and compromise seeking. As [94] found, resident rejection could be reduced by about 10% stretching on the investment's contribution to a long-term green-house gas emission reduction and the economic benefits of the specific project.

  In that light, we suggest conducting a public, wide-covering information campaign. This should be developed in a way that it is comprehensively addressing the need and advantages of a global electricity network. Such campaigns can be backed with the extensive research that has been conducted by CIGRE on social and environmental aspects of transmission system development during the past decade.

9.2 Standardization

Standardization issues will represent one of the big challenges for the success of Global Electricity Interconnection (GEI), which demands an unprecedented degree of system integration across geographical boundaries, highly specialized technologies, operational patterns and commercial agreements. Existing and especially future Standards basis will be necessary to allow efficient technical procurement, support communication through standardized terminology and concepts, ensure interoperability, certify and test new equipment, and maintain competitive markets for technical components.

Drawing up GEI concepts at an early stage by a consensus-based standardization process and through close cooperation between researchers, industry, regulators and the standardization bodies is one of the key requirements for success of a multi-phased implementation of GEI. These principles shall be applied to the core technologies that support GEI: HVDC, UHV transmission, clean energy generation and Smart Grids. This will facilitate subsequent promotion and application of equipment, interfaces, processes so that to create suitable conditions for building international and eventually global level interconnections.

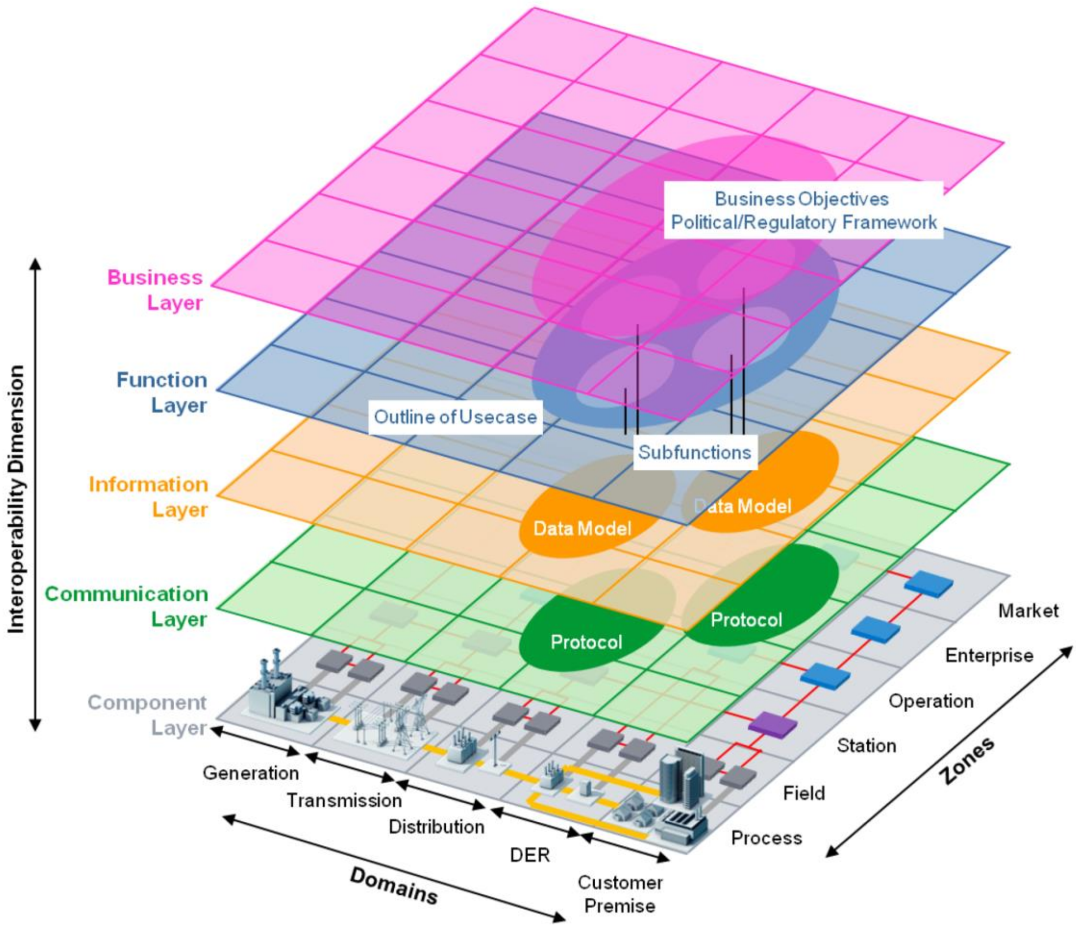


Figure 9-3 GEI addresses the whole system - SGAM gives the systematic methodology to structure the needs on standardization

9.2.1 Present situation and future standardization needs

Some standards currently exist that cover the foundational technical domains of GEI, required for incorporating multiple technologies into parts of a very complicated, large-scale power and energy system that will interconnect not only physical infrastructures across large areas but also the supporting ICT systems.

Smart Grid implementation has already started and will continue to be implemented in the form of an "evolution" of successive projects over several decades. It is now necessary to manage the integration of new equipment that has a lower life span than traditional network assets: three to five years for consumer electronics and telecommunications, compared to 40 plus years for lines, cables, transformers.

The Smart Grid represents a technical challenge that goes far beyond the simple addition of an information technology infrastructure on top of an electrotechnical infrastructure: each device that is connected to a Smart Grid is simultaneously an electrotechnical device and an intelligent node. Today's "connection" standards need to address both aspects concurrently.

Adopting advanced monitoring and control technologies is a key objective for future Smart Grids; specifications are necessary for coordinating the control and protection strategy of interconnecting links and grid connection codes.

Systems standards

New tools between standards developing organizations (SDOs) and stakeholders, such as creating use case repositories and system level standards, must be launched to bridge gaps between organizations working in different areas. Drafting of systems level standards will require understanding he interrelationship between other components from a physical/electrical point of view, as well as the flow of information with the grid and changes in system behaviour.

From a conformity assessment perspective, understanding is also required of how the life of a standard evolves as changes occur at the component surroundings levels. Most importantly, system level standardization thinking for GEI is the understanding of the interrelation between the many systems-of-systems and the growing equipment assets that make up the GEI system.

In the International Electrotechnical Commission (IEC), a Systems Committee Smart Energy has been set up to provide systems level standardization, coordination and guidance in the areas of Smart Grid and Smart Energy, including interactions with heat and gas. Key International standards such as IEC 61850 have been introduced to ensure device and communication compatibility in substations, while IEC 61970 has been developed to define application programme interfaces for energy management systems. The Systems Committee Smart Energy has just begun its outreach to various internal and external stakeholders, but much work remains to be coordinated.

Data management standards

Open data and data sharing facilitate data analytics and simulation, which provide the basis for planning, scheduling, operation and control. The large efficiency gains from integration and interoperability, however, are only realized if all the stakeholders collaborate effectively and agree to share data or information. Data management shall become a key issue in GEI, including data analytics, data utilization, data privacy and cyber security. The lack of exchange of fundamental data on customers, infrastructures and operations is one of the most important barriers highlighted by stakeholders already now at infant stage of GEI. Specifications for data sharing and standards on data format are both needed.

Although many regional and national organizations, such as NERC, ENTSO-E, NGET, have their own standards fo operation and planning, it is necessary to coordinate such criteria at a wider level for the GEI.

Control, protection and scheduling for GEI depends upon effective information exchange based on appropriate ICT architectures. Therefore the Smart Grid core International Standards (IEC 61850, IEC 61968 and IEC 61970), must be studied further to see if they can accommodate GEI, or whether it will be necessary to develop new Standards or to revise current ones. Cyber security is another major challenge for GEI, for which corresponding standards.

Standards for new materials and equipment

In GEI, energy would be globally exchanged via the interconnected networks, with UHV grids constituting the backbone and clean energy the main resource; therefore consideration should be given to new areas of standardization based on new material discoveries or environmental challenges that will further enable a GEI system to be established.

Higher voltage level UHV technologies will be a prerequisite for transmitting large capacity power across long distances encompassing remote sites and wild areas, like polar regions, desert areas, equatorial forests, marine paths. Since the UHV transmission systems must adapt to such extreme environmental operating conditions, new energy conducting materials may need to be engineered and new reliability guidelines developed for this purpose.

At the same time, with the rollout of local energy communities and microgrids, a growing need of electrical storage and cross-sector energy transformation will be installed both at customer sites and at grid nodes, excess generation of RES shall transferred and/or stored to gas or in the form of hydrogen gas, thereby necessitating standards for energy transfer and energy storage technologies. In most cases, standardization plays a stabilizing role by pursuing research activities on which real market opportunities are built.

9.2.2 The role of International Electrotechnical Commission (IEC)

Cigre is the most widespread platform to exchange knowledge and experiences among all actors of the power system value chain and has therefore become the most authoritative place for shaping consensus on technical issues, also in some cases negotiating between diverging or even conflicting poistions; so its Technical Brochures and set of publications is universaly considered a sort of pre-normative stage for elaboration of standards, which shall then be adopted formally by the official Standardization organisations.

IEC is the most relevant Standardization organisation for power systems and so also for GEI. Moreover, IEC has just started to work on GEI, so it is very much useful to assess the cross-implications and ideally the complementarities with the outcome of C1.35 reported in this Technical Brochure.

The standards involved in GEI are dealt with into many technical committees inside IEC, some of which also tightly connected to other coordinating organizations outside IEC. The following is a list of current IEC technical committees (TCs) and subcommittees (SCs) handling specific activities that support GEI (see Figure 9.4).

In particular, ACTAD is the Advisory Committee on Electricity Transmission and Distribution, an umbrella body within IEC for matters related to Transmission and Distributions.

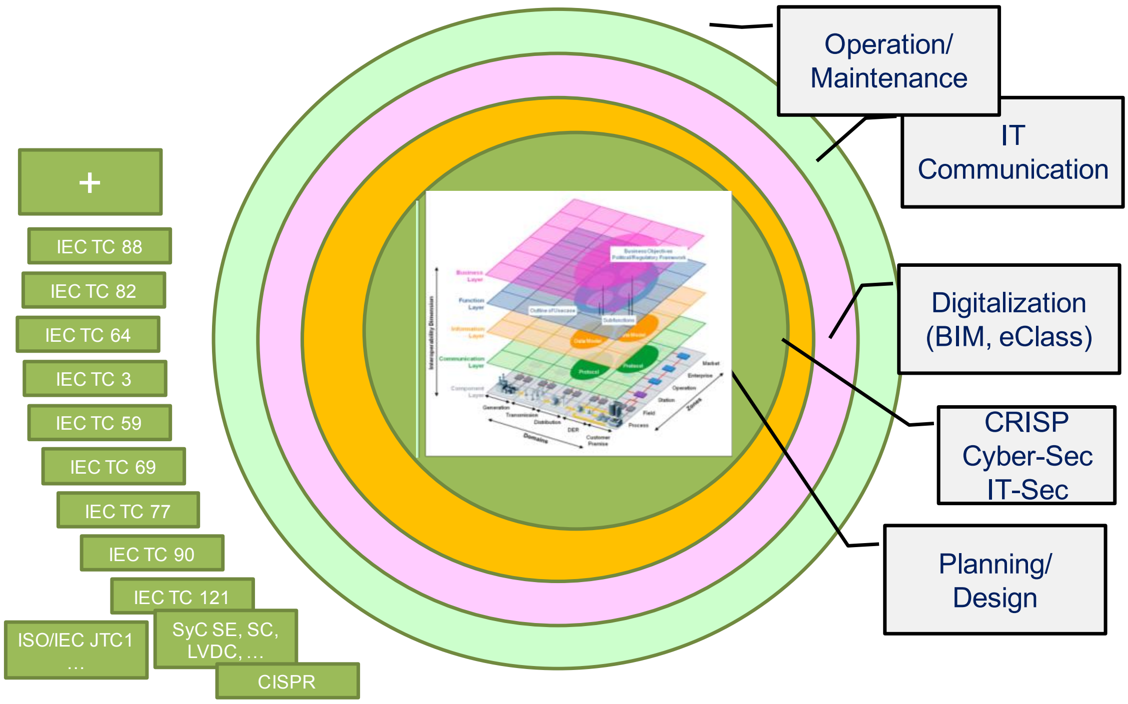


Figure 9-4 IEC Committees and cross horizontal areas to be involved in GEI

9.2.3 The activities of IEC - ACTAD on GEI

In year 2016, IEC has published a White Paper on GEI (publicly available at https://www.iec.ch/whitepaper/globalenergy/), pulling together experts' opinions and state-fo-the-art on the many fields impacted by GEI (generation, transport, smart grids, regulation, enabling technolgies, social barriers, economics and financial considerations). Following the publication and discussions on such White Paper, the deep interest shown by the technical community brought about the decision to set up a specific task force:

- To define in detail and describe the scope of work of IEC bodies on GEI;
- To carry out the review MSB White Paper & recommend its update;
- To identify which standardization issues enter into the picture and how based on this to analyse the need of missing products and missing standards.

The starting point are the following:

- Which cross country-continental political frame conditions are pre-requisites for a successful realization of the global Energy System interconnection?
- Which political frame conditions have to be considered in the context of national policies on own power mix, self-sufficiency generation rate, incentives to certain generation or storage technologies?
- Which technical principles (reliability, security, resilience, etc.) are to be used as boundary conditions and with which priority?
- Do power economic/market aspects of GEI need to be addressed in this early, conceptual stage?
- Is it necessary to set up a unified global Energy System scenario and grid planning instruments, like for example those in place in Europe within ENTSO-E TYNPD (Joint Network Plan on a 10 years horizon) including also standardised CBA (Cost Benefit Analysis)?

- Is it necessary, at some early stage of realisation phase, to set up a unified set of operating rules, like for example supranational legally binding Network Codes in Europe (ENTSO-E)?
- Is it advisable, at this early concept stage to accurately take into consideration technical/geographical limits for possible routings: submarine constraints, sea depth, rugged territory, high mountain ranges, politically sensible areas, protected areas, environmental challenges, or straight-line transmission path may be considered?
- Which organization can moderate, accompany and subsequently enact the whole approach?

9.2.4 Preliminary findings and conclusions

On technical standardisation

In general terms, equipment technological standards are essential in order to ensure interoperability and avoid individual manufacturer's reaching a monopolist role. In the framework of smart grids, connection standards need to cover electrotechnical and ICT aspects concurrently.

However, for GEI, at this initial stage, it seems that technical standardisation is not the main issue to solve; for example, for HVDC links between large AC grids, uniform technical standards are not indispensable. AC grids interconnected through point-to-point HVDC, can be operated also with different internal standards, and HVDC terminals are treated as a generator/consumer nodes; control & protection strategy though must be coordinated.

For large scale deployment of GEI, it shall instead become important a good degree of standardization of the transmission links to be realised, in termms of: technology, voltage, modular capacity, common boundary conditions, design principles and technical specifications. These shall be the building blocks of interconnection corridors, leveraging on the lessons learnt from the realisation of the initial links.

On standardisation of processes

At an initial stage, standardisation for GEI comes into the scene more for systems and for processes than for equipment. Scenario building, as well as assumptions for design / boundary conditions, even if not standardised, should be made at least with mutual consistency, both bilaterally between neighbouring countries and multilaterally among all countries involved in the energy flows. Plannng criteria should be harmonised across macro-regions large enough to contemplate the impact of future interconnections under consideration. Simulations and grid studies, which become paramount in complex interconnected systems, require a certain degree of standardised equipment/solutions to be defined. Data communication and IT processes management shall require high level of standardisation, probably more and before than the power components.

For proper CBA analysis, benefit assessment criteria should be standardised in order to make it meaningful the comparison among different projects and proposals; instead, investment cost are already standardised across projects), - Cost Benefit Analysis criteria should be standardised for same reasons. Business models to implement interconnection projects would benefit from identifying standard and replicable models; this relates to: roles of different partners, allocation and sharing of costs and benefits between partners and between jurisdictions, risk management. Commercial agreements would also benefit from standardisation (for example Power Purchase Agreements) for thesame reasons. Procurement procedures need a good standardisation level, both for technical specifications and for tendering / evaluation processes.

9.3 Institutional and Regulatory Coordination

The interconnections identified in the various scenarios would connect power systems belonging to different jurisdictions. To build these interconnections, the involved governments together with System Operators, investors, energy regulators and any other concerned stakeholders need to coordinate the institutional and regulatory frameworks that will set the basis for cross-border electricity trading. Since setting up institutional and regulatory frameworks will require integrating countries with substantial differences in the electricity sector regulation, the coordination should be done step-by-step, rather than all at once.

9.3.1 Conceptual design, proposed model, and regional institutions

The regulations and institutions needed for cross-border electricity trading could be developed in different phases, as shown in the scheme here below. This step-by-step approach will allow flexibility to deal with the complexities of establishing a regional market, particularly at the initial period.

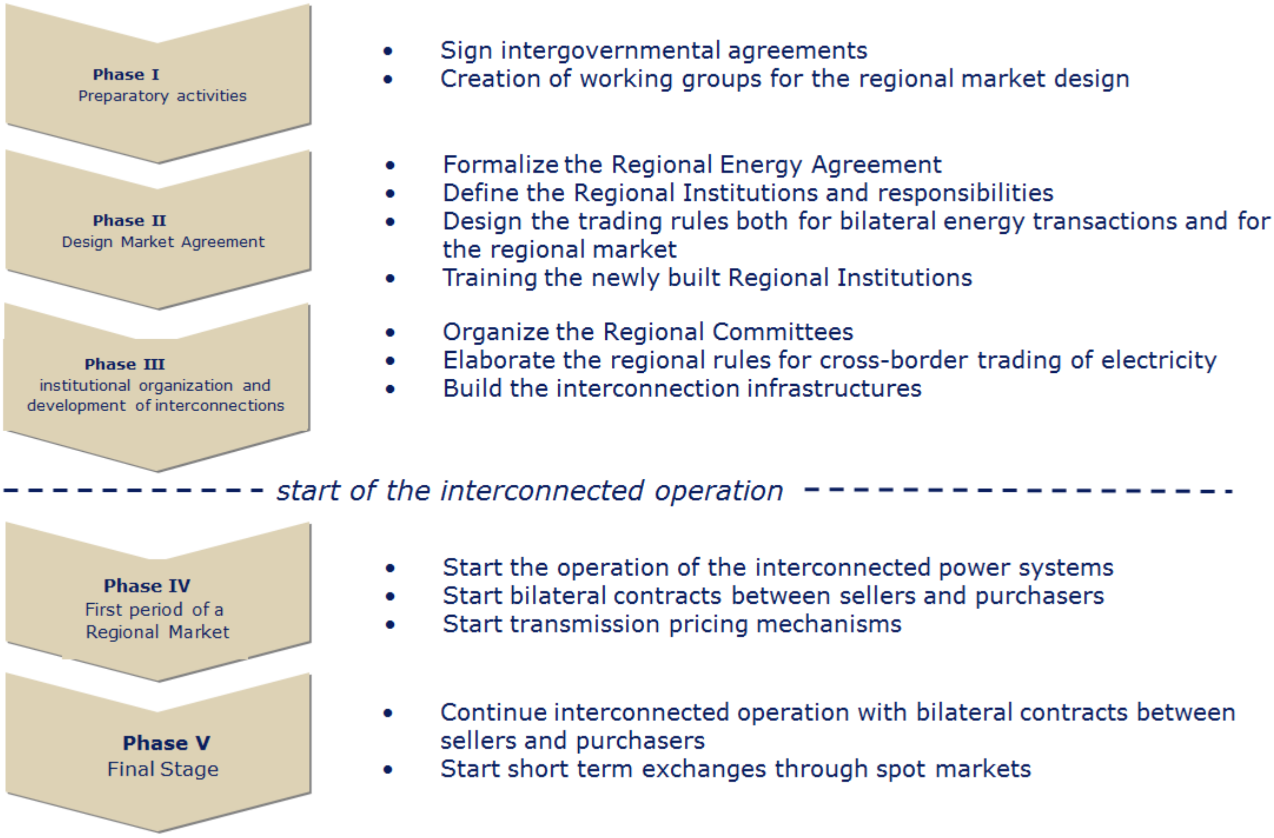


Figure 9-5: Phases for Establishing a Regional Electricity Market

Phase I: Preparatory Activities

The preparatory phase for each interconnection project would include:

- Seek government support from all involved countries to move the interconnection project forward. The political support can be translated into a declaration, or a letter of intent signed by governmental authorities stating the principles and objectives of collaboration towards regional power market integration.
- Create working groups to further study the regulatory, technical, and economic aspects of the interconnection.
- Execute detailed technical analyses of the interconnection, in particular technical, economic and environmental feasibility studies including definition of technical specifications up to the preparation of tendering documents.

Phase II: Design Market Agreements

The main activities this phase would be:

- Develop and formalize a Regional Energy Agreement (REA) among the concerned jurisdictions. The REA will focus on:

  - Non-discriminatory conditions for trading energy and provisions to ensure reliable cross-border energy transit flows through grids.
  - Developing the infrastructures required within each jurisdiction to avoid any bottleneck in the power flows across the interconnection.
  - Dispute resolution among participating states and between investors and governments.
  - Promoting energy efficiency and attempts to minimize the environmental impact of energy production and use.
- Define of the regional institutions and regulations
  - At least the following two organizations shall be put in place:
  - Regional Energy Committee to propose regional agreements and to develop and enforce rules and standards for the cross-border trading of electricity. The Regional Energy Committee would have dispute resolution capabilities, would coordinate market evolution, and would be empowered to make decisions on important political issues.
  - Regional System Committee to supervise and control the national Transmission System Operators.
  - Note: further regional institutions may also be envisaged in a later stage of interconnected operation such as Regional Energy Regulator, like in ACER in Europe.
- Design regional regulations for bilateral trading, including short-term transactions that may arise from V-RES generation:
  - Trading rules: the rules on how to manage the bilateral energy exchanges shall be designed: from the definition of the contracts to the settlement of the invoices, accounting also that energy transaction may entail power wheeling across several countries
  - Sharing the costs and benefits for the development and use of the infrastructures necessary for the bilateral transactions.
  - Standards for bilateral transactions (contracts, warranties, liabilities, etc.).
- Design regional regulations for a regional market:
  - Trading rules: these rules refer to the energy exchanges across the interconnector in the framework of a more advanced regional power market (e.g.: Day-Ahead Market, Intra-Day Market, Ancillary Service Market, Forward Market) .
  - Sharing the costs and benefits of regional projects.
  - Implementing regional projects.
  - Standards for regional energy transactions in a context of more advance market products (contracts, warranties, liabilities, capacity allocation, congestion management, inter-TSO compensation mechanisms, etc.).

Phase III: Institutional Organization and Developing the Interconnection

The main activities in this phase would be:

- Operationalize the Regional Energy Committee and Regional System Committee designed in Phase II
- Elaborate the rules for bilateral energy transactions, so to establish a market code for bilateral exchanges. Bilateral energy transactions do not mean necessary a transaction between one seller and one purchasers, but, given the large size of the interconnection, these transactions can be set between a pool of sellers (GenCo's) and a cluster of purchasers (aggregate of consumers)
- Elaborate and develop regional regulations and standards for the cross-border trading of electricity related to advanced market products, e.g.: develop the bidding process to contract the capacity of the interconnection.
- Build the physical infrastructures.
- Train the newly built Regional Committees.

Phase IV: First Period of a Regional Market

By the beginning of this phase, the physical infrastructure will be completed and the institutions will be prepared to oversee cross-border trading. The main activities in this phase would be:

- Initiate the operation of the interconnected power systems and related commercial coordination.
- Bilateral agreements between countries.

- Start the activities of the regional power system and market operations.

In this time interval, energy trading will rely on bilateral transactions between producers and purchasers. Possible long-term power purchase agreements (PPA) can be established based on the generation availability, mostly from RES. PPA can reduce risk for investors in new power plants and transmission infrastructures. These contracts should be agreed before building the new power plants. In this way, Independent Power Producers (IPP) in one country can enter PPAs with off-takers throughout the future interconnected regions.

To operationalize the interconnected transmission grid, two contracts are needed for sellers/purchasers:

- With the *transmission owner* for the remuneration required for the use of the interconnection.
- With the *system operator* to coordinate the flows in the power system within its jurisdiction, such as power dispatch, voltage control, and maintenance plans. The system operator can be in the form of Independent System Operator (ISO), like the ONS in Brazil, CAISO and other system operators in USA, etc. Alternatively, it could be a Transmission System Operator (TSO) that operates and owns the transmission assets, like RTE in France, Terna in Italy, FGC-UES in Russia, etc.

These contracts are independent from the financing model to build and operate the interconnection lines—regulated, merchant, or hybrid model.

Phase V: Final Period

In this phase, a regional spot market would develop alongside bilateral markets. The activities in this phase would include:

- Bilateral agreements between countries, based on standard commercial instruments.
- Short-term exchanges through the spot market; other energy exchanges related to the various market products.
- Regional transmission pricing.

To allow IPPs to trade on the spot market, power transmission capacity must be allocated by the transmission owner in a non-discriminatory and transparent way. The simplest way is to start with explicit auctions, in which transfer capacity is auctioned to the market players for a fixed period.

9.3.2 Overcoming barriers

To make the large size interconnections work, there must be a credible way for the involved countries to resolve disputes in the regional interest. Political leaders in all countries will need to make important decisions to develop the integrated electricity market. Those decisions will allow for the countries to:

- Participate in the design of the regional institutions and regulation.
- Participate in setting regional rules and standards through the Regional Energy Committee and the Regional System Committee.
- Harmonize their national markets with regional rules.
- In many regions, steps are also needed to strengthen domestic energy markets to prepare for regional integration.

For the regional institutions to be effective, they will need to be staffed with well-trained and qualified personnel. Education and training of staff should be an on-going process, starting with initial intensive training. Training methods should include interactive seminars, information exchanges with governing institutions for electricity trading in other regions, and access to regulatory and industry publications and research.

9.3.3 Risks for the implementation and operation of the Interconnections

Building and operating the large size of the Interconnections identified I the scenario simulations is a challenging objective. Besides the above recalled barriers to be overcome, some risks shall be highlighted:

Geopolitical risks. The construction of the interconnections entails massive investments also in new generation, mostly RES, located in countries that might not have a stable political over decades. In fact, the investments in new generation and interconnection assets are spread over several years and they would be recovered over a quite long period (10, 20 years). This requires stable political conditions in the involved countries and good political relationships among them.

Environmental and social risks. The construction of new power plants and interconnection lines would have inevitably an impact on the territory and the environment in general. The acceptance of the new infrastructures by the affected population is not granted. Compensations and mitigation measures shall be foreseen, but sometimes the opposition to new infrastructures has led to significant delays in the time schedule of the infrastructure construction.

Institutional and legal risks. Developing a regional institutional, legal, and regulatory framework is essential for realizing the potential of the Interconnection. Creation of harmonized and share rules for the cross-border trading of electricity among different jurisdictions is not straightforward and requires an open and continuous support from the highest governmental level. The regulatory framework shall be defined well in advance with respect to the commissioning of the interconnections to give assurances against potential investors in new generation assets as well as in the construction of the interconnections

Financial risks. Building the Interconnections requires huge investments in large generation and transmission projects. To attract the financing required to build these projects, they must offer solid returns on investment to public (including governments and development financing institutions) or private entities. The feasibility studies shall address not only the economic profitability of the interconnections, but shall show also their bankability through appropriate financial analyses.

Operational risks. Operating such large interconnected power systems requires strong cooperation between the operators of each transmission system. The involved countries have varying experience and adopt different operation criteria. Cooperation and technical assistance between the TSOs is suggested to build capacity and ensure secure operation of the interconnected system.

9.3.4 Concluding remarks

Building and operating the bulk interconnection across continents requires deep institutional and regulatory coordination. The main components of this coordination are:

- **Political support**—Without government support, the interconnections cannot advance. Governments can state this support by signing a declaration that sets out the principles and areas of collaboration.
- **Regional legal framework**—Considering the huge upfront investment effort in transmission assets and new power plants, a clear legal framework is essential to attract private investors. Investment risks can be lowered by including appropriate clauses in the contracts between market players that clearly state dispute resolution mechanisms.
- **Bilateral energy trading** —The market model for energy trading and using transmission capacity should be as simple as possible, especially in the early stages of interconnected operations. Therefore, we propose starting cross-border trading with bilateral contracts in the form of PPA between generators and buyers. The bilateral contracts should include provisions to ensure the settlement of economic transactions between the buyer and the seller, as well as penalties in case one of the parties doesn't comply with the contractual engagements
- **Regional market model**—The regional market model in a mature power market would see the coexistence of bilateral energy trading and short term energy transactions on a spot market where the various market agents (sellers, purchasers, traders) operate
- **Access to the transmission grid**—The transmission system should be open to connection of IPPs. Remuneration for using the grid should be transparent, non-discriminatory and, as far as possible, stable over the time. Transmission fees should reflect costs.
- **Regional institutions**—We suggest setting up a Regional Energy Committee and a Regional System Committee. Building and operating a large interconnection corridor may be assigned to a Regional Transmission Company or coordinated among the national system operators.
- **Regulatory harmonization**—While some national reforms are needed, regional rules should minimize interference with domestic policy. This will allow the intercontinental/interregional Interconnection to be developed more quickly, and will continue to give national governments freedom to set domestic policy.

10. Conclusion and future work

This work proposes a model-based, quantitative analysis evaluating the benefits and costs of building a global electricity interconnection, as a means of effectively integrating RES on a massive scale and mitigating climate risk. The analysis, which relies on an open source optimization-based tool, aims at selecting and sizing power generation, transmission corridors and technologies in order to supply electricity demand across a set of regions spanning the globe at minimum cost, while accounting for investment and operational technology costs as well as technical constraints. In addition to publiclyavailable data sources, the dataset employed to instantiate the model is constructed from a comprehensive, reanalysis-based assessment of worldwide variable renewable energy resource potential, a careful analysis of global electricity demand patterns on various temporal scales, as well as a detailed review of technologies suitable for large-scale and long-haul electricity transmission.

In this report, a case study is proposed to assess the potential of a global grid. More precisely, a set of key indicators is defined, including power generation and transmission system costs, electricity cost, RES share and CO_2 emissions level. Then, a set of cases is constructed, and indicator values are computed for each case and compared to that of a base case assuming the absence of interconnections between regions. Overall, results suggest significant improvements in all key indicators when interconnections are allowed. Indeed, it is found that the possibility of building interconnections between regions promotes the massive deployment of wind and solar PV, which replace a significant share of fossil fuel-based generation capacity. Substantial increases in RES shares in the electricity mix, from 53% in the base case to a maximum of 76%, and drastic reductions in CO_2 emissions levels, from 840 to a minimum of 220 Mt/year considering the availability of storage technologies, ensue. In terms of costs, the shift in electricity mix from fossil fuel-based power plants to V-RES technologies sharply decreases operating expenses, e.g. VOM, fuel and carbon costs, thus leading to electricity cost reductions from 54 €/MWh in the base case to a minimum of 48 €/MWh.

A common feature across all considered cases is the large interconnection capacities built around Central Asia, which can be explained by the very good local wind resource, with an average capacity factor of 40%, the very good solar PV potential in adjacent regions, such as South Asia and the Middle East, and its geographic role as a transmission hub linking superior V-RES locations to massive demand centers in East and South Asia. Moreover, given the very long distances assumed between neighboring regions, DC is the preferred interconnection technology, while OHL AC lines are used only to connect regions whose connection points are in close geographical proximity such as Central and South Asia or East and South-East Asia.

To test results robustness, sensitivity analyses are performed on selected parameters. Firstly, the impact of V-RES resource quality on the outcome of the model is investigated. In particular, altering wind capacity factor values in Central and East Asia, with a 10% decrease and a 3% increase, respectively, results in the replacement of more than 500 GW of wind turbines previously sited in Central Asia by additional V-RES capacities in neighboring regions, i.e. South, South-East and East Asia. In addition, the South-East to East Asian tie is reinforced in order to facilitate the integration of large shares of solar PV and wind generation, as well as the exchange between these two major demand centers. While an electricity cost increase of 1 €/MWh is observed, little change in RES share and CO_2 emissions level is recorded. Next, the impact of active power losses in interconnections and higher technology costs is studied. On the one hand, assuming zero losses across interconnections naturally leads to increased transmission capacities at similar costs, which in turn results in higher V-RES capacities deployed in regions with superior resource quality. On the other hand, increasing transmission costs leads to lower interconnection capacities, with longer or submarine routes most affected, and corresponding increase in local V-RES as well as natural gas-fired generation capacity deployment. Because of the emergence of fossil fuel-based electricity production, the cost of electricity increases by 3 €/MWh and CO_2 emissions soar by 100 Mt/year, respectively.

In addition, the CO2 price (i.e., carbon tax) is likely a critical parameter defining to a large extent the economic viability of the proposed interconnections.

Moreover, the impact of storage systems is also assessed using generic storage models. When daily storage is made available, PV deployments are favored over wind and gas-fired installed capacities, especially in regions with superior solar potential. As expected, the availability of storage leads to less interconnection capacity worldwide, yet the interconnections between South, South-East and East Asia are reinforced in order to enable the supply of massive amounts of solar PV to demand centers in the area. When seasonal storage is considered, wind and solar PV capacities increase, making gas-fired generation less attractive globally. Counterintuitively, interconnection capacities increase slightly, especially in regions adjacent to Central Asia. Regardless of the sub-case considered, storage addition leads to decreased system costs and CO2 emissions levels, due to increased RES shares.

In addition, the impact of a change in the topology of the proposed network is also investigated. More specifically, the North America – UPS link, which is consistently built across cases and thus constitutes a key transmission corridor, is removed from the list of potential interconnections. In this setup, the Europe – North Atlantic – North America corridor, which did not emerge previously, now appears. Owing to the high costs of laying submarine cables, the associated transmission capacity is relatively small. Moreover, as the only direct link between the American continent and East Asia is no longer an option, renewable-based electricity flows into North America decrease significantly, which in turn leads to a noticeable increase in gas-fired power plant capacity deployed in this region.

Finally, the system design which would allow to supply the global electricity demand solely though V-RES and interconnections is probed. Clearly, the resulting system configuration features massively oversized wind, solar PV power plants and interconnection capacities, leading to electricity prices around 120 €/MWh if only solar is used and 58 €/MWh if a combination of wind and solar is employed, as well as curtailment volumes on the order of 57000 TWh and 22000 TWh, respectively, to serve a demand of 40000 TWh.

Though sensitive to interconnection costs or transmission corridor choices, results consistently show that if a high carbon price can be agreed upon on a global level, the construction of interconnections allows to decrease both the cost of supplying global electricity demand and greenhouse gas emissions. Hence, as the number and size of interconnections keeps growing across the world, a global electricity grid may be envisaged as a valuable asset eventually connecting regions and continents to form a unique, cost-effective, low-carbon power system. This report essentially focussed on the techno-economic aspects of such a project. However, for the vision to materialize, challenges of a non-technical or economic nature will need to be overcome. In particular, in addition to issues pertaining to political will formation, social acceptance as well as long-term engagement and close cooperation between numerous international stakeholders, it is clear that designing proper legislation, regulatory frameworks and processes enabling or facilitating the construction, ownership and operation of such strategic infrastructure as well as the establishment of appropriate market structures will be key to the success of the project. In summary, the results of this study indicate that a global grid may constitute a cost-effective means of supplying global electricity demand and mitigating climate risk. This report therefore paves the way for further investigations, contributes to the debate on climate and energy policies in the context of the energy transition, and informs policy and decision-makers.

Thus, several future work avenues can be suggested. Firstly, in the current model, building interconnections between regions constitutes the only carbon-free option to effectively integrate RES on a large scale and provide flexibility to the system. Hence, accounting for alternatives such as specific storage technologies and demand response, for instance, would allow to study the interaction between technological options offering flexibility and enable a more robust assessment of optimal system designs. Alternatively, increasing the spatial resolution and number of regions considered would allow to refine V-RES potential and electricity demand estimates, better capture complementarity in RES and load patterns across regions, and eventually provide a more accurate assessment of interconnection needs. Then, exploring other scenarios with additional constraints of a technical, economic or political nature, would allow to gain a deeper insight into system design choices enabling a low-carbon, worldwide energy supply. Lastly, investigating the legal and administrative aspects of such a project would prove highly valuable in identifying practical challenges and solutions that would enable the vision to materialize.

Appendix A: Definitions, abreviations

A.1. General terms

Acronym	Phrase
AC	Alternating Current
CCS	Carbon Capture and Storage
CSC	Current Source Converter
DC	Direct Current
ENTSO-E	European Network Transmission
FACTS	Flexible Alternating Current Transmission System
GCC	Gulf Cooperation Council
GEI	Global Electricity Interconnection
GMAO	Global Modelling and Assimilation Office
GW	Giga Watt
HTS	High Temperature Superconducting
HVDC	High Voltage Direct Current
IEA	International Energy Agency
IEC	International Electrotechnical Commission
IGBT	Insulated Gate Bipolar Transistor
IPP	Independent Power Producer
IRENA	International Renewable Energy Agency
ISO	Independent System Operator
JRC	Joint Research Centre
LCC HVDC	Line Commutated Converter-Based High Voltage DC
MENA	Middle East and North Africa
OHL	Over Head Line
PV	Photo Voltaic
RES	Renewable Energy Sources
TB	Technical Brochure
ToR	Terms of Reference
TWh	Tera Watt Hour
UHVDC	Ultra High Voltage Direct Current
UPS	Unified Power System of Russia
UTC	Universal Time Coordinated
VSC	Voltage Source Converter
WEC	World Energy Council
WG	Working Group

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Appendix C: Specific appendix

C.1. Terms of reference

CIGRE Study Committee C1

PROPOSAL FOR THE CREATION OF A NEW WORKING GROUP (1)

WG* N° C1.35	Name of Convenor : Jun Yu (CN) E-mail address: yu-jun@sgcc.com.cn	
Technical Issues # (2): 4, 7, 10	Strategic Directions # (3): 1, 3, 4	
The WG applies to distribution networks (4): Only indirectly		
Title of the Group: Global electricity network feasibility study		

Scope, deliverables and proposed time schedule of the Group :

Background :

The concept of a global electricity network would address the challenges, benefits and issues of uneven distribution of energy resources across the world, as they affect the goal to achieve overall sustainable energy development. A global electricity network can be envisaged to consist of inter-continental and cross-border backbone interconnections as well as the power grids (transmission and distribution networks) in all interconnected countries at various voltage levels. The global electricity network would take advantage of diversity from different time zones, seasons, load patterns and RES intermittent availability, thus supporting a balanced coordination of power supply of all interconnected countries.

The large-scale utilization of fossil energy has resulted in a series of prominent problems such as occasional resource shortages, environmental pollution and climate change. Based on Ultra High Voltage AC/DC, smart grid technologies, and clean energy generation, the global electricity network would hopefully provide a secure, manageable, affordable, renewable, technologically advantageous and sound solution for sustainable and reliable energy supply.

To date, few studies of such a future global network have been undertaken, and barriers for its realisation would be paramount, requiring political vision and a worldwide collaborative mood, however the high potential rewards of such a concept deserve a scientific, expert-based and truly international effort, well matching CIGRE's distinctive character of unbiased vision and worldwide excellence.

Scope :

To carry out the first known feasibility study by grid experts from countries of all continents, on the technical challenges, potential benefits, economic viability, fit with global energy policies and environmental impact for the concept of a global electricity network. The main steps are:

1. Collect relevant data on energy supply, consumption and transportation patterns from international organisations, in particular IEA, for the different areas of the world (areas to be identified with energy-interdependency criteria); search and review relevant prior work, in particular CIGRE's Network of the Future paper.
2. Adopt one reference long term scenario for consumption and supply volumes, which shall be credible, prudent, consistent with the global climate protection goals of 2 ton CO_2 equivalent emissions per person and per year, which implies electrification of heating and transport; the scenario shall be considered more as an input than a focus of the WG study, therefore effort shall be placed on sound and robust selection/adaptation of existing authoritative projections and making them consistent worldwide, rather than on building/arguing the scenario itself or sensitivity cases.

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3. Identify key grid technologies and architectures to be then utilised as building blocks of the new interconnections. This shall consider AC vs DC solutions, underground vs OHL splitting, voltage levels, capacity levels, number of parallel circuits/redundancy & reliability levels, basic HVDC configuration (bipolar vs multi-monopolar schemes, ground/sea return vs metallic return, converter technology, cable performances).
4. Sketch possible global transmission links at both intra-continental and inter-continental scale with particular effort in coordinating the overall picture. This would extend to large links which do not exist nor get studied today between neighbouring areas, for example: between Central Asia, India, China and Siberia, between Europe, North Africa and Middle East, between Canada and the US sunny deserts and windy prairies, between the Amazon immense potential and the load centers further south, between Australia and the South-East Asia. Subsea cables connecting areas and continents shall also be considered, after identifying the technical limits and performances expected in the selected time-horizon.
5. Provide a rough estimation of the economic viability of the major interconnections, based on a very simplified model for optimizing the overall system costs, comprising construction and operation of conventional and renewables power plants, of storage facilities, of transmission grids between areas; under certain boundary conditions (cap on CO_2 emissions, minimum self-sufficiency rate per country, etc.), the model shall consider a 1-node-per-area topology, i.e. neglecting transmission issues inside each area, in order to capture first-order effects and mega-trends (at least at an approximate abstract level), like the daily and seasonal interplay of hydro, wind, sun, and time-zone differences (e.g. peak PV production time moves regularly across longitude). Aiming at both dimensions of energy (TWh) and capacity (GW), each node has attached demand and load patterns, RES potentials and production, transmission connections to neighbouring nodes; demand in every area has to be met in every time-span (initially corresponding only to day-night and main seasons) by the selected technology mix and inter-area transmission capacities. Only a static approach is used: dynamic issues are out of scope. Upon consolidation of this macro-approach, future studies can be conducted with larger granularity, time-wise and space-wise.
6. Identify specific advantages of global interconnections as additional to those deriving from the parallel processes of subcontinental-scale grid integration, of deployment of smart grids, demand response and battery storage; in very basic terms, this means to analyse the trade-off between investing in more transmission or more generation, especially fossil fuelled; the trade-off shall be not only in economic terms, but also in environmental impact (CO_2, footprint, etc.).
7. Identify separately technical and socio-economic challenges for the realisation of global interconnections; provide a qualitative roadmap to overcome such barriers.
8. Summarise previous analysis into a description of costs, benefits, risks, challenges, and factors required for a global network to become feasible in the coming decades. To the extent made possible by the confidence level of the input data and of the depth of the analysis, extract some general principles and criteria for such feasibility to materialise; these may differ by continent.

Time Schedule: December 2015 – August 2018

Agreed ToR: Dec. 2015

1st WG meeting: Q1/2016

Collection of available data: Q2/2016

2nd WG meeting: Aug. 2016 (Paris)

Scenarios defined: Fall 2016

Possible transmission schemes and sketches defined: Q1/2017 WG meeting, milestone report to C1: May 2017 (Dublin) Viability estimation after scope step 4: Summer – Fall 2017 WG meeting to discuss draft report: Winter Q4/2017 Presentation to C1 at the 2018 CIGRE Session, August 2018 Final report: Fall 2018 **Deliverables :** Technical brochure, summary in Electra, Tutorials, conference presentations
Comments from Chairmen of SCs concerned :
Approval by Technical Committee Chairman : M. Waldron **Date :** 25/02/2016

(1) or Joint Working Group (JWG) - (2) See attached table 1 – (3) See attached table 2
(4) Delete as appropriate

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Table 1: Technical Issues of the TC project "Network of the Future" (cf. Electra 256 June 2011)

1	Active Distribution Networks resulting in bidirectional flows within distribution level and to the upstream network.
2	The application of advanced metering and resulting massive need for exchange of information.
3	The growth in the application of HVDC and power electronics at all voltage levels and its impact on power quality, system control, and system security, and standardisation.
4	The need for the development and massive installation of energy storage systems, and the impact this can have on the power system development and operation.
5	New concepts for system operation and control to take account of active customer interactions and different generation types.
6	New concepts for protection to respond to the developing grid and different characteristics of generation.
7	New concepts in planning to take into account increasing environmental constraints, and new technology solutions for active and reactive power flow control.
8	New tools for system technical performance assessment, because of new Customer, Generator and Network characteristics.
9	Increase of right of way capacity and use of overhead, underground and subsea infrastructure, and its consequence on the technical performance and reliability of the network.
10	An increasing need for keeping Stakeholders aware of the technical and commercial consequences and keeping them engaged during the development of the network of the future.

Table 2: Strategic directions of the TC (cf. Electra 249 April 2010)

1	The electrical power system of the future
2	Making the best use of the existing system
3	Focus on the environment and sustainability
4	Preparation of material readable for non technical audience

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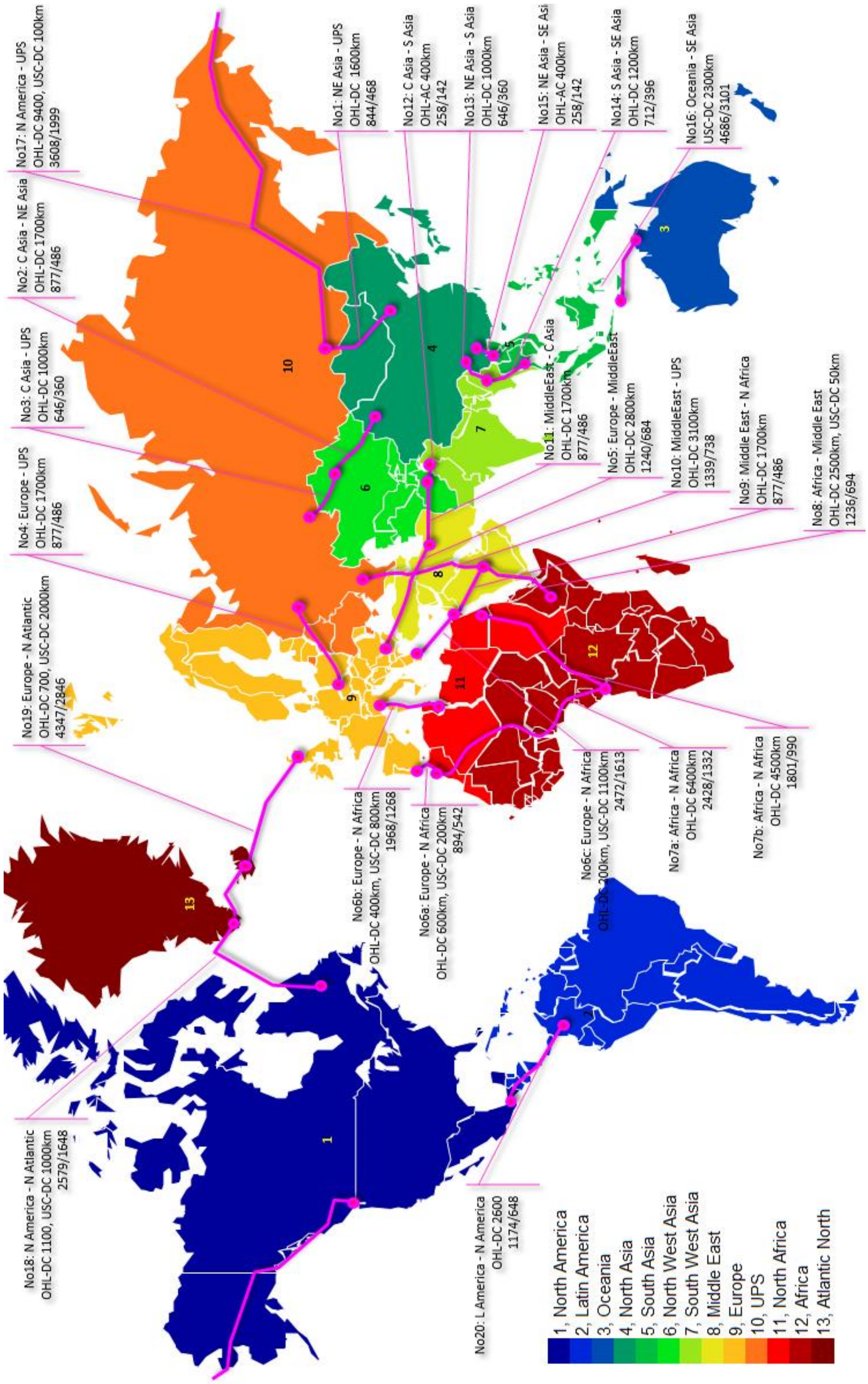
C.2. Transmission corridors



Connection Points & Corridor Lengths

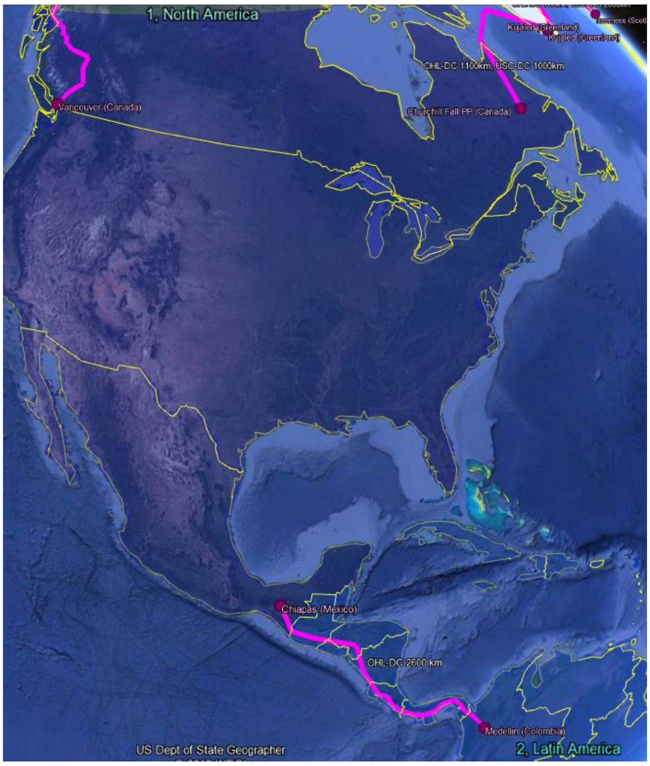
	Node A			Node B			Length (km)				
Ref.	**Region**	**No**	**Location**	**Name**	**No**	**Location**	**DC OHL**	**DC USC**	**AC OHL**	**AC USC**	**Total**
1	**N.East Asia**	**4**	China (Hebei)	**UPS**	**10**	Irkoutsk (Hydro PP near Baikal lake)	1 600				1 600
2	**N.East Asia**	**4**	China (Xinjiang, Urumqi)	**Central Asia**	**6**	Kazakhstan (Astana)	1 700				1 700
3	**Central Asia**	**6**	Kazakhstan (Astana)	**UPS**	**10**	Russia (Chelyabinsk NPP)	1 000				1 000
4	**Europe**	**9**	Germany border	**UPS**	**10**	Russia (Moscow)	1 700				1 700
5	**Europe**	**9**	Bulgaria (Europe)	**Middle East**	**8**	Iran (Teheran)	2 800				2 800
6a	**Europe**	**9**	Portugal	**North-Africa**	**11**	Morroco (Rabbat)	600	200			800
6b	**Europe**	**9**	Italy (La Spezia)	**North-Africa**	**11**	South Tunisia	400	800			1 200
6c	**Europe**	**9**	Greece (Athena)	**North-Africa**	**11**	Egypt (Suez)	200	1 100			1 300
7a	**Africa**	**12**	RDC (Inga)	**North-Africa**	**11**	Morroco (Rabbat)	6 400				6 400
7b	**Africa**	**12**	RDC (Inga)	**North-Africa**	**11**	Egypt (Aswan)	4 500				4 500
8	**Africa**	**12**	Ethiopia (Addis Abeba)	**Middle East**	**8**	Soudi-Arabia (Rhyad)	2 500	50			2 550
9	**Middle East**	**8**	Soudi-Arabia (Rhyad)	**North-Africa**	**11**	Egypt (Suez)	1 700				1 700
10	**Middle East**	**8**	Soudi-Arabia (Rhyad)	**UPS**	**10**	Russia (Vogodonsk NPP)	3 100				3 100
11	**Middle East**	**8**	Iran (Teheran)	**Central Asia**	**6**	Afghanistan (Kaboul)	1 700				1 700
12	**Central Asia**	**6**	Afghanistan (Kaboul)	**South Asia**	**7**	Pakistan (Islamabad)			400		400
13	**N.East Asia**	**4**	China (Kuming in Yunan province)	**South Asia**	**7**	Myanmar (Mandalay)	1 000				1 000
14	**S.East Asia**	**5**	Thailand (Bangkok)	**South Asia**	**7**	Myanmar (Mandalay)	1 200				1 200
15	**N.East Asia**	**4**	China (Nanning in Guanxi province)	**S.East Asia**	**5**	Vietnam (Hanoi)			400		400
16	**Oceania**	**3**	Australia (Darwin)	**S.East Asia**	**5**	Indonesia (Java, Surabaya)		2 300			2 300
17	**North America**	**1**	Canada (Vancouver)	**UPS**	**10**	Irkoutsk (Hydro PP near	9 400	100			9 500
18	**North America**	**1**	Canada, Churchill Falls	**North Atlantic**	**13**	Greenland (South), Kujalleq	1 100	1 000			2 100
19	**Europe**	**9**	UK, Scotland	**North Atlantic**	**13**	Greenland (South), Kujalleq	700	2 000			2 700
20	**Latin America**	**2**	Colombia (Medelin)	**North America**	**1**	Mexico (Chiapas)	2 600				2 600
							45 900	**7 550**	**800**	**0**	**54 250**
							84,6%	**13,9%**	**1,5%**	**0,0%**	**100,0%**

Estimated Costs of Corridors

	Node A			Node B			Length (km)					Cost for 1 GW transmission capacity (MEUR)											
												OHL		USC		2 x		1 x BtoB (for		TOTAL			
Ref.	Region	No	Location	Name	No	Location	DC OHL	DC USC	AC OHL	AC USC	Total	maxi	mini	maxi	mini	maxi	mini	maxi	mini	maxi	mini	moy	
1	N.East Asia	4	China (Hebei)	UPS	10	Irkoutsk (Hydro PP near Baikal lake)	1 600				1 600	528	288	0	0	316	180			844	468	656	2,2%
2	N.East Asia	4	China (Xinjiang, Urumqi)	Central Asia	6	Kazakhstan (Astana)	1 700				1 700	561	306	0	0	316	180			877	486	682	2,3%
3	Central Asia	6	Kazakhstan (Astana)	UPS	10	Russia (Chelyabinsk NPP)	1 000				1 000	330	180	0	0	316	180			646	360	503	1,7%
4	Europe	9	Germany border	UPS	10	Russia (Moscow)	1 700				1 700	561	306	0	0	316	180			877	486	682	2,3%
5	Europe	9	Bulgaria (Europe)	Middle East	8	Iran (Teheran)	2 800				2 800	924	504	0	0	316	180			1 240	684	962	3,3%
6a	Europe	9	Portugal	North-Africa	11	Morroco (Rabbat)	600	200			800	198	108	380	254	316	180			894	542	718	2,5%
6b	Europe	9	Italy (La Spezia)	North-Africa	11	South Tunisia	400	800			1 200	132	72	1 520	1 016	316	180			1 968	1 268	1 618	5,5%
6c	Europe	9	Greece (Athena)	North-Africa	11	Egypt (Suez)	200	1 100			1 300	66	36	2 090	1 397	316	180			2 472	1 613	2 043	7,0%
7a	Africa	12	RDC (Inga)	North-Africa	11	Morroco (Rabbat)	6 400				6 400	2 112	1 152	0	0	316	180			2 428	1 332	1 880	6,4%
7b	Africa	12	RDC (Inga)	North-Africa	11	Egypt (Aswan)	4 500				4 500	1 485	810	0	0	316	180			1 801	990	1 396	4,8%
8	Africa	12	Ethiopia (Addis Abeba)	Middle East	8	Soudi-Arabia (Rhyad)	2 500	50			2 550	825	450	95	64	316	180			1 236	694	965	3,3%
9	Middle East	8	Soudi-Arabia (Rhyad)	North-Africa	11	Egypt (Suez)	1 700				1 700	561	306	0	0	316	180			877	486	682	2,3%
10	Middle East	8	Soudi-Arabia (Rhyad)	UPS	10	Russia (Vogodonsk NPP)	3 100				3 100	1 023	558	0	0	316	180			1 339	738	1 039	3,5%
11	Middle East	8	Iran (Teheran)	Central Asia	6	Afghanistan (Kaboul)	1 700				1 700	561	306	0	0	316	180			877	486	682	2,3%
12	Central Asia	6	Afghanistan (Kaboul)	South Asia	7	Pakistan (Islamabad)			400		400	100	52	0	0			158	90	258	142	200	0,7%
13	N.East Asia	4	China (Kuming in Yunan province)	South Asia	7	Myanmar (Mandalay)	1 000				1 000	330	180	0	0	316	180			646	360	503	1,7%
14	S.East Asia	5	Thailand (Bangkok)	South Asia	7	Myanmar (Mandalay)	1 200				1 200	396	216	0	0	316	180			712	396	554	1,9%
15	N.East Asia	4	China (Nanning in Guanxi province)	S.East Asia	5	Vietnam (Hanoi)			400		400	100	52	0	0			158	90	258	142	200	0,7%
16	Oceania	3	Australia (Darwin)	S.East Asia	5	Indonesia (Java, Surabaya)		2 300			2 300	0	0	4 370	2 921	316	180			4 686	3 101	3 894	13,3%
17	North America	1	Canada (Vancouver)	UPS	10	Irkoutsk (Hydro PP near	9 400	100			9 500	3 102	1 692	190	127	316	180			3 608	1 999	2 804	9,6%
18	North America	1	Canada, Churchill Falls	North Atlantic	13	Greenland (South), Kujalleq	1 100	1 000			2 100	363	198	1 900	1 270	316	180			2 579	1 648	2 114	7,2%
19	Europe	9	UK, Scotland	North Atlantic	13	Greenland (South), Kujalleq	700	2 000			2 700	231	126	3 800	2 540	316	180			4 347	2 846	3 597	12,3%
20	Latin America	2	Colombia (Medelin)	North America	1	Mexico (Chiapas)	2 600				2 600	858	468	0	0	316	180			1 174	648	911	3,1%
							45 900	7 550	800	0	54 250								total	36 644	21 915	29 279	100%
							84,6%	13,9%	1,5%	0,0%	100,0%								/km/G	0,68	0,40	0,54	

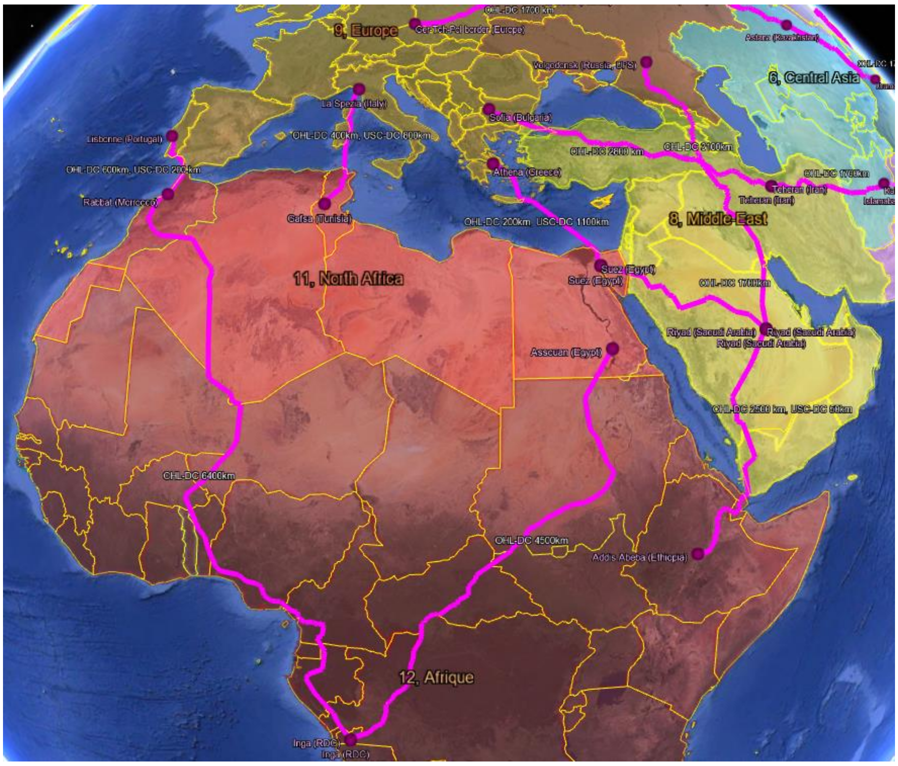
Corridor Routes

N. America – North Atlantic – Latin America

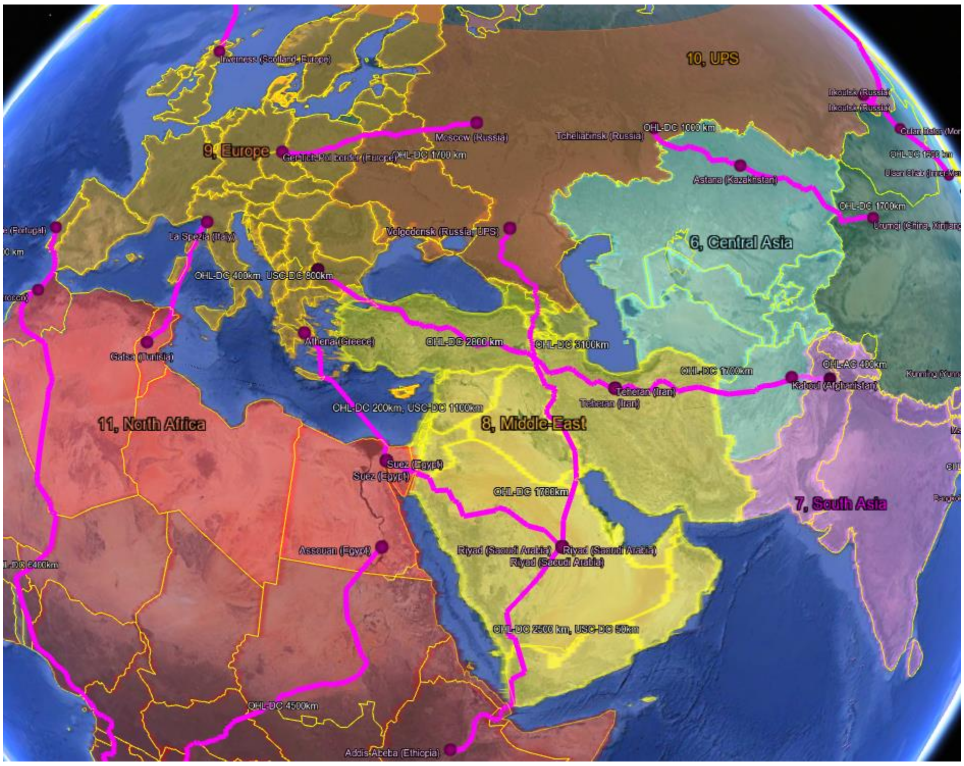


North Atlantic – Europe – UPS – North Africa – Middle East

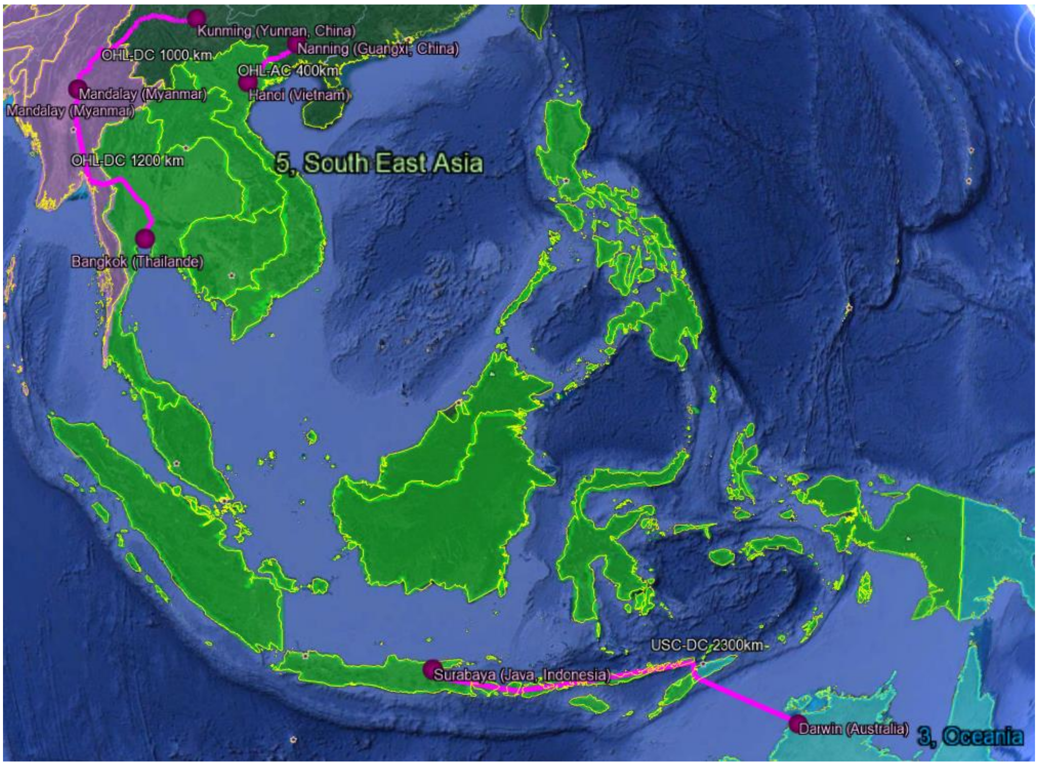
North Africa – Africa – Middle East



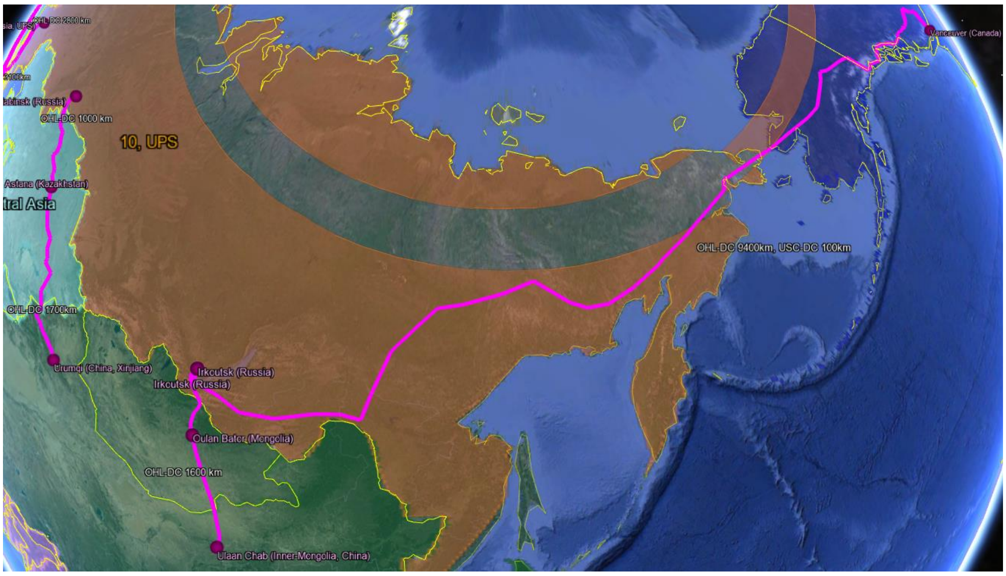
Europe – N. Africa – M. East – UPS – Central Asia – S. Asia



East Asia – South Asia - South East Asia – Oceania



UPS- North America – North East Asia – Central Asia



C.3. Additional WEC Input Data

Unfinished Symphony economic indicators

Indicator	2014	2020	2030	2040	2050	2060
Population (million)	7266	7758	8501	9157	9725	10184
GDP (trillion US$2010)	70	84	114	152	199	256
GDP per capita (US$2010)	9686	10871	13396	16602	20473	25172
Primary Energy Intensity (MTOE/US$2010)	194	172	134	100	76	59
Final Energy Intensity (MTOE/US$2010)	133	123	98	76	58	45

Unfinished Symphony electricity generation (TWh)

Energy (TWh)	2014	2020	2030	2040	2050	2060
Coal	9697	8791	7741	4483	547	86
Coal (with CCS)	0	0	95	530	981	982
Oil	1033	651	381	241	133	76
Gas	5155	6362	7014	6927	4486	822
Gas (with CCS)	0	0	82	1227	4414	6694
Nuclear	2535	3299	4367	5496	6546	7617
Hydro	3895	4440	5109	5695	6447	7100
Biomass	493	710	1187	1663	2150	2339
Biomass (with CCS)	0	0	0	30	77	169
Wind	717	1320	2918	4928	7431	9326
Solar	198	501	1694	3760	5802	7943
Geothermal	77	142	262	448	735	1111
Other	15	0	5	24	93	210
Total	23815	26216	30855	35452	39842	44475

Unfinished Symphony Carbon emissions

Carbon emissions	2014	2020	2030	2040	2050	2060
CO2 emissions (GtCO2/yr)	32.38	32.6	31.1	25.8	18.1	12.6
CO2 per capita (tCO2/yr)	4.46	4.2	3.7	2.8	1.9	1.2

C.4. Hourly Demand Curve Availability per Region Data

Region C1.35	Country	Population in 2015 *(thousands)*	Population in 2050 *(thousands)*	2015 - Electricity consumption (TWh)	load pattern 2015	load pattern 2016
1	Canada	35940	44136	544,5	1	1
	USA	321774	388865	4128,5	1	1
	Mexico	127017	163754	269,8	1	1
2	Argentina	43417	55445	134,1	1	1
	Bolivia	10725	15963	7,7		
	Brazil	207848	238270	523		1
	Chile	17948	21601	71,7	1	1
	Colombia	48229	54927	59,4	1	1
	Cuba	11390	10339	17,2		
	Dominican Republic	10528	13238	16,2		
	Ecuador	16144	23013	23		
	Guatemala	16343	27754	9,8		
	Haiti	10711	14189	0,4		
	Honduras	8075	11217	7,8		
	Paraguay	6639	8895	11		
	Peru	31377	41899	42,9	1	1
	Uruguay	3432	3667	10,9		
	Venezuela	31108	41562	76,2		
3	Australia	23969	33496	238,1		1
	New Zealand	4529	5607	41,4		
	Cook Island, Fiji, …	1000	1100			
	Tonga, Tuvalu, Vanuatu	400	500			
4	China	1376049	1348056	4876,7		1
	Hong-Kong	7288	8148	44		
	Japan	126573	107411	949,2		1
	Mongolia	2959	4028	5,3		
	North-Korea	25240	26970	10,2		
	South-Korea	50293	50593	495,3		1
	Chinese Taipei	23400	24000	230,7		

5	Brunei	423	546	3,9		
	Cambodia	15578	22545	4,9		
	Indonesia	257564	322237	202,8		
	Laos	6802	10172			
	Malaysia	30331	40725	132,5		
	Myanmar	53897	63575	13,4		
	Philippines	100699	148260	67,8		
	Singapore	5604	6681	47,5		
	Thailand	67959	62452	174,8		1
	Timor-Leste	1185	2162			
	Vietnam	93448	112783	143,4		
6	Afghanistan	32527	55955	5		
	Azerbaijan	9754	10963	17,6		
	Kazakhstan	17625	22447	68,2		
	Kyrgyzstan	5940	8248	10,6		
	Tajikistan	8482	14288	12,4		
	Turkmenistan	5374	6555	12,4		
	Uzbekistan	29893	37126	46,5		
7	Bangladesh	160966	202209	48,6		
	Bhutan	775	950			
	India	1311051	1705333	1027	1	1
	Maldives	364	494			
	Nepal	28514	36159	3,9		
	Pakistan	188925	309640	88,9		
	Sri-Lanka	20715	20836	11,7		
8	Georgia	4000	3483	9,9	1	1
	Turkey	78666	95819	214,8	1	1
	Bahrain	1377	1822	27,8	1	1
	Iran	79109	92219	211	1	1
	Iraq	36423	83652	35,6	1	1
	Israel	8064	12610	54,4	1	1
	Jordan	7595	11717	16,1	1	1
	Kuwait	3892	5924	43,3	1	1
	Lebanon	5851	5610	16,6	1	1
	Oman	4491	5844	28,9	1	1
	Qatar	2235	3205	36,4	1	1
	Saudi Arabia	31540	46059	292,8	1	1
	Syria	18502	34902	12,9	1	1
	United Arab Emirates	9157	12789	111,1	1	1
	Yemen	26832	47170	3,1	1	1
	Azerbaijan	9754	10963	17,6	1	1

9	Albania	2897	2710	2,3		
	Austria	8545	8846	69,6	1	1
	Belgium	11299	12527	85	1	1
	Bosnia&Herzegovina	3810	3069	12	1	1
	Bulgaria	7150	5154	33,2	1	1
	Croatia	4240	3554	17	1	1
	Cyprus	1165	1402	4,4	1	1
	Czech Republic	10543	9965	63,4	1	1
	Denmark	5669	6299	32,4	1	1
	Estonia	1313	1129	8,1	1	1
	Finland	5503	5752	82,5	1	1
	France	64395	71137	475,4	1	1
	Germany	80689	74513	520,6	1	1
	Greece	10955	9705	51,2	1	1
	Hungary	9855	8318	40,8	1	1
	Ireland	4688	5789	27	1	1
	Italy	59798	56513	314,3	1	1
	Latvia	1971	1593	7,2	1	1
	Lithuania	2878	2375	10,9	1	1
	Luxembourg	567	803	6,4	1	1
	Malta	419	411	3,4	1	1
	Montenegro	626	574	7,4	1	1
	Netherlands	16925	17602	112,5	1	1
	Norway	5211	6658	128,3	1	1
	Poland	38612	33136	151,1	1	1
	Portugal	10350	9216	49	1	1
	Romania	19511	15207	54,8	1	1
	Serbia	8851	7331	39,3	1	1
	Slovakia	5426	4892	27,2	1	1
	Slovenia	2068	1942	13,6	1	1
	Spain	46122	44840	262,9	1	1
	Sweden	9779	11881	135,9	1	1
	Switzerland	8299	10019	63,4	1	1
	United Kingdom	64716	75361	340,2	1	1
10	Belarus	9496	8125	29,2		
	Russia	143457	128599	726,3	1	
	Ukraine	44824	35117	118,9		1

11	Algeria	39667	56461	50,1		
	Egypt	91508	151111	154,2		
	Libya	6278	8371	9,8		
	Morocco	34378	43696	29,9		
	Tunisia	11254	13476	14,4		
	Israel	8064	12610	54,4		
	Western Sahara	573	901			
	Sudan	40235	80284	10,6		
12	Angola	25002	65473	8,4		
	Benin	10880	22549	1,1		
	Botswana	2262	3389	3,5		
	Cameroon	23344	48362	5,8		
	Central African Republic	4900	8782			
	Cote d'Ivoire	22702	48797	6		
	Chad	14037	35131			
	RDC	77267	195277	7,3		
	Equatorial Guinea	845	1816			
	Ethiopia	99391	188455	8,3		1
	Gabon	1725	3164	1,8		
	Gambia	1991	4981			
	Ghana	27410	50071	8,6		1
	Kenya	46050	95505	7,9		1
	Lesotho	2135	2987			
	Liberia	4503	9436			
	Malawi	17215	43155			
	Mali	17600	45404			
	Mauritania	4068	8049			
	Mozambique	27978	65544	13,4		1
	Namibia	2459	4322	3,8		1
	Niger	19899	72238	0,9		
	Nigeria	182202	398508	25		1
	Congo	4602	10732	0,8		
	Senegal	15129	36223	3,4		
	South Africa	54490	65540	198,5	1	1
	Swaziland	1287	1792			
	Tanzania	53880	137000	3,9		
	Togo	7305	15681	1,2		
	Uganda	39 032	101 873	2,7		1
	Zambia	16212	42975	11,4		
	Zimbabwe	15603	29615	6,8		
	Total	**7190212**	**9417572**	**20902,1**		

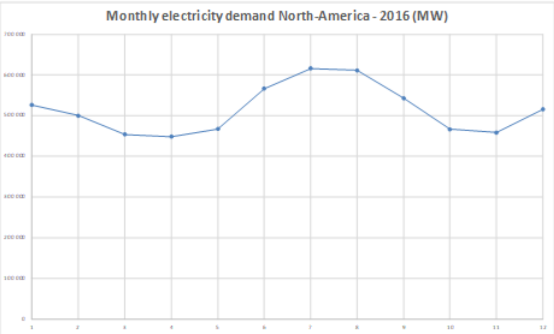
C.5. Summary of input data per region per Region Data

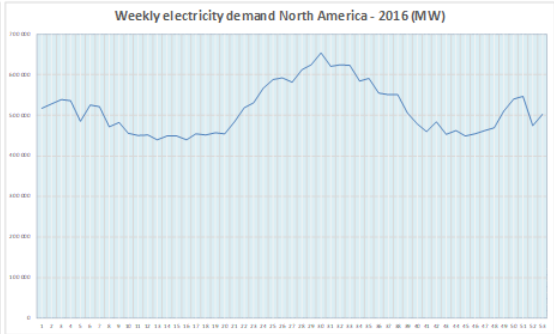
Region 1 – North America

Country	Population (thousands)		Electricity Demand (TWh)	
	2015	2050	2015	2050
Canada	35940	44136	544.5	N/A
USA	321774	388865	4128.5	N/A
Mexico	127017	163754	269.8	N/A
Total	*484731*	*596755*	*4942.8*	*6671*
(Notes)	increase of 23%			

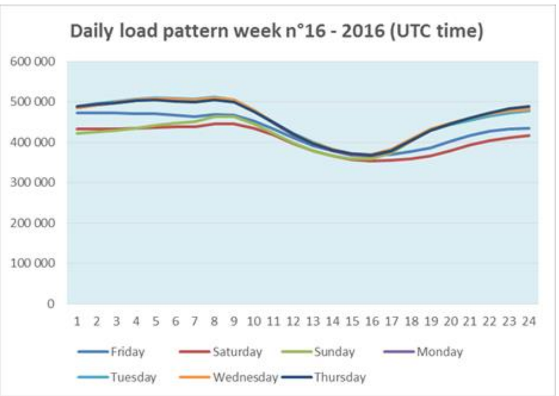
Source: World Population Prospects United Nations, 2015, IEA statistics, CIGRE C1.35

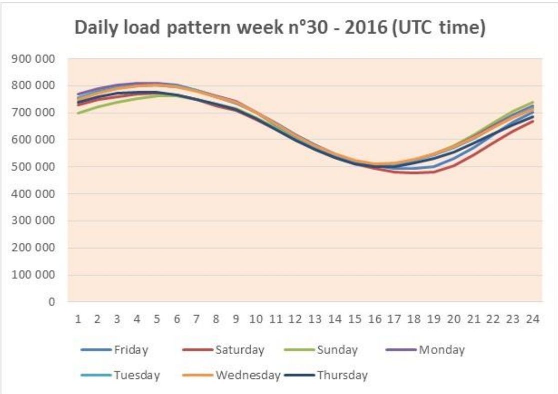
Electricity Demand Patterns

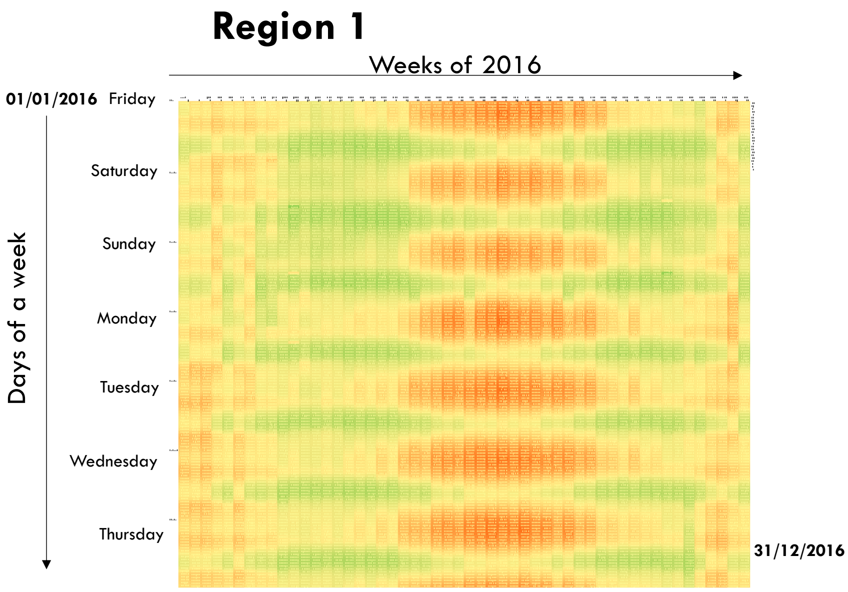




Source: CIGRE C1.35 survey. Peak period in summer (e.g., July, August). Off-peak period in autumn/spring (e.g., October, March). Average value = 515 GW, Max = +55%, min= - 32%.







Electricity Generation and Installed Capacities

Technology	2010		2050 (WEC – Unfinished Symphony)		2050 (C1.35)	
	Generation (TWh)	Installed Capacity (GW)	Generation (TWh)	Installed Capacity (GW)	Generation (TWh)	Installed Capacity (GW)
Hydro	650	160	942	248	950	295
Wind	130	80	2086	819	2701	913
Solar			691	401	492	342
Geothermal	30	20	313	60		
Biomass	30	10	106	24	6	3
Coal	2120	315	270	40	156	28
Oil	100	80				
Nuclear	940	130	1319	151	1185	175
Natural Gas	1200	520	1476	423	1181	682
Total	**5200**	**1315**	**7203**	**2167**	**6671**	**2438**

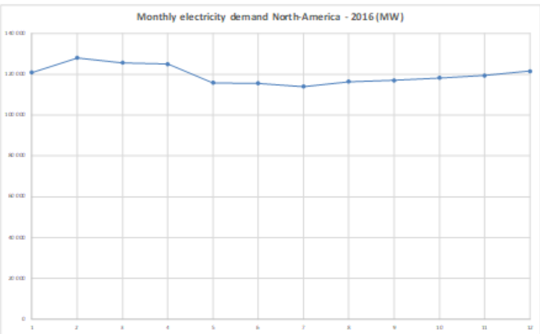
Source: World Energy Council 2013, 2016; CIGRE C1.35.

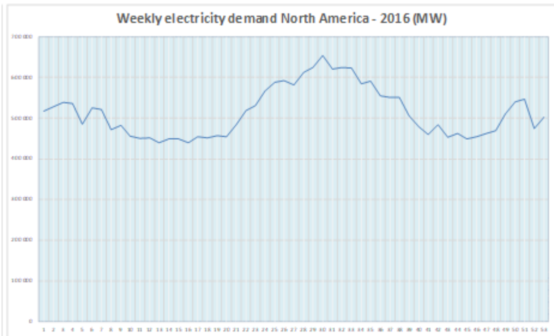
Region 2 – South America

Country	Population (thousands)		Electricity Demand (TWh)	
	2015	2050	2015	2050
Argentina	43417	55445	134.1	N/A
Bolivia	10725	15963	7.7	N/A
Brazil	207848	238270	523	N/A
Chile	17948	21601	71.7	N/A
Colombia	48229	54927	59.4	N/A
Cuba	11390	10339	17.2	N/A
Dom. Republic	10528	13238	16.2	N/A
Ecuador	16144	23013	23	N/A
Guatemala	16343	27754	9.8	N/A
Haiti	10711	14189	0.4	N/A
Honduras	8075	11217	7.8	N/A
Paraguay	6639	8895	11	N/A
Peru	31377	41899	42.9	N/A
Uruguay	3432	3667	10.9	N/A
Venezuela	31108	41562	76.2	N/A
Total	474681	582785	1011	2740
(Notes)	increase of 23%			

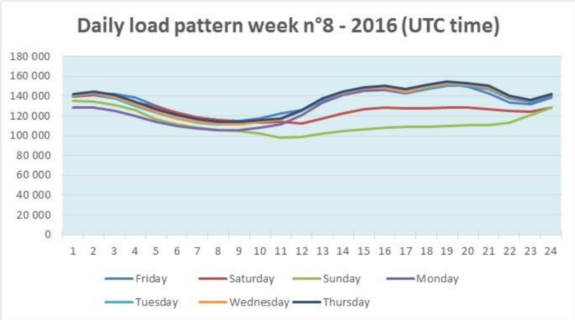
Source: World Population Prospects United Nations, 2015, IEA statistics, CIGRE C1.35.

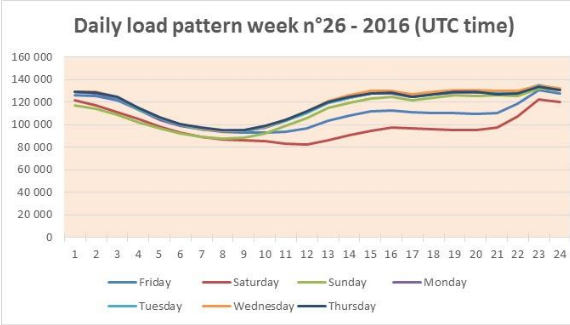
Electricity Demand Patterns

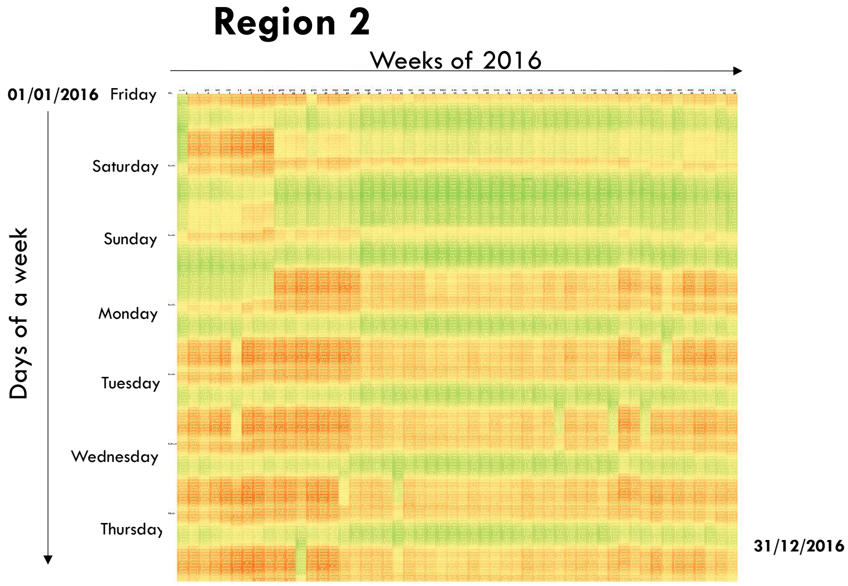




Source: CIGRE C1.35 survey.







Electricity Generation and Installed Capacities

Technology	2010		2050 (WEC – Unfinished Symphony)		2050 (C1.35)	
	Generation (TWh)	Installed Capacity (GW)	Generation (TWh)	Installed Capacity (GW)	Generation (TWh)	Installed Capacity (GW)
Hydro	700	130	1240	248	1248	268
Wind	0	0	279	112	670	224
Solar	10	5	297	171	323	196
Geothermal	0	0				
Biomass	60	20	489	73	196	74
Coal	40	20	20	4	17	3
Oil	140	20				
Nuclear	20	5	113	24	103	17
Natural Gas	180	60	338	85	184	123
Total	*1150*	*260*	*2777*	*716*	*2740*	*904*

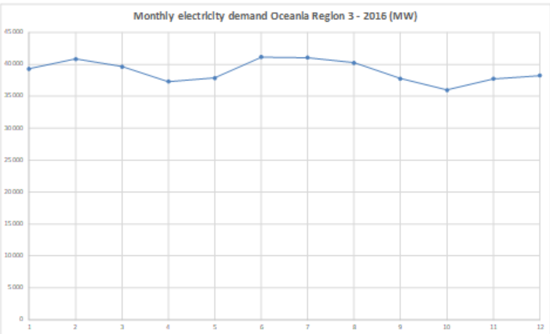
Source: World Energy Council 2013, 2016; CIGRE C1.35.

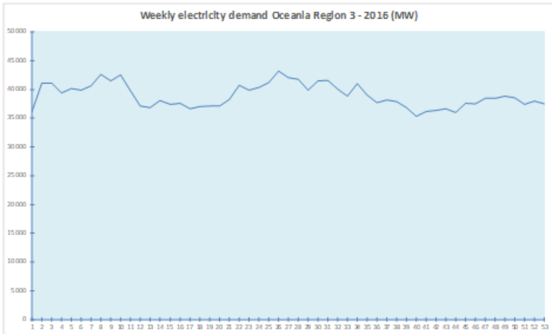
Region 3 – Oceania

Country	Population (thousands)		Electricity Demand (TWh)	
	2015	2050	2015	2050
Australia	23969	33496	238.1	N/A
New Zealand	4529	5607	41.4	N/A
Cook Island, Fiji, …	1000	1100	N/A	N/A
Tonga, Tuvalu, Vanuatu	400	500	N/A	N/A
Total	*29898*	*40703*	*279.5*	*959*
(Notes)	increase of 36%			

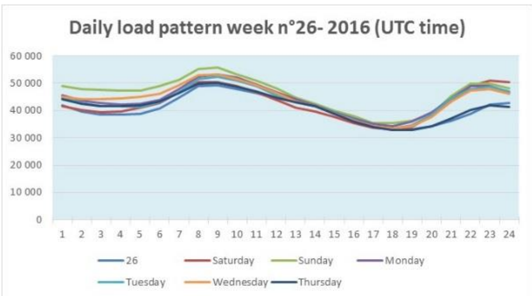
Source: World Population Prospects United Nations, 2015, IEA statistics, CIGRE C1.35.

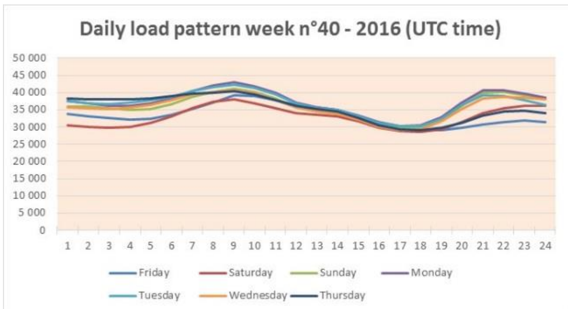
Electricity Demand Patterns

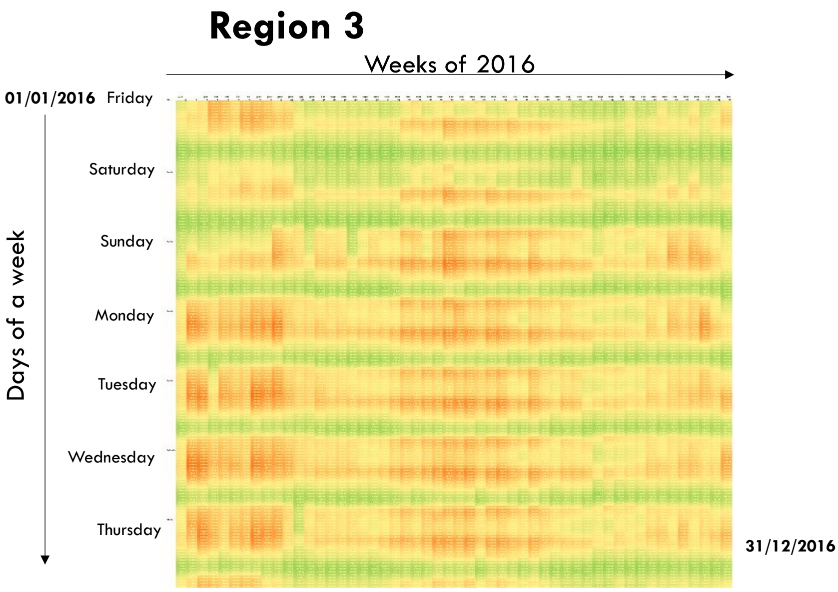




Source: CIGRE C1.35 survey. The load pattern is relatively flat, with an average value of 38 GW. Nevertheless, winter (e.g., June, July) and summer (e.g., February) peaks are visible. Off-peak period occurring during autumn/spring. Average value over the year around 39 GW, Max = +44%, min = -28%.







Electricity Generation and Installed Capacities

Technology	2010 Generation (TWh)	2010 Installed Capacity (GW)	2050 (WEC – Unfinished Symphony) Generation (TWh)	2050 (WEC – Unfinished Symphony) Installed Capacity (GW)	2050 (C1.35) Generation (TWh)	2050 (C1.35) Installed Capacity (GW)
Hydro	42	12	118	28	122	45
Wind	7	3	62	31	372	121
Solar	0	7	210	111	176	110
Geothermal	10	2	52	0		
Biomass	0	0	35	11	7	4
Coal	123	12	44	8	26	4
Oil	27	8	0	0		
Nuclear	0	0	57	9	52	8
Natural Gas	125	30	266	75	204	107
Total	*333*	*73*	*845*	*273*	*959*	*398*

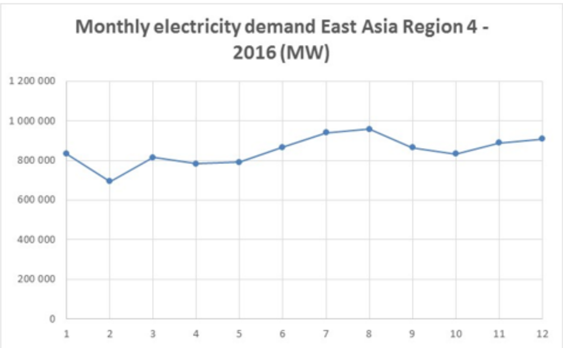
Source: World Energy Council 2013, 2016; CIGRE C1.35.

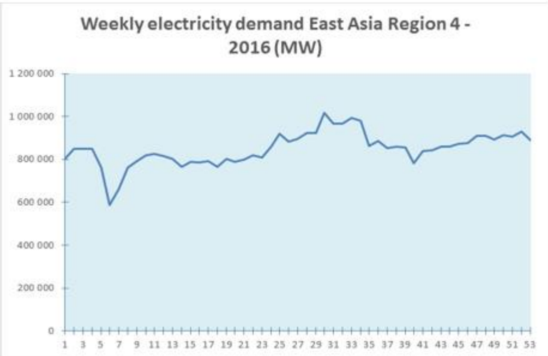
Region 4 – East Asia

Country	Population (thousands)		Electricity Demand (TWh)	
	2015	2050	2015	2050
China	1376049	1348056	4876.7	N/A
Hong-Kong	7288	8148	44	N/A
Japan	126573	107411	949.2	N/A
Mongolia	2959	4028	5.3	N/A
South-Korea	50293	50593	495.3	N/A
Chinese Taipei	23400	24000	230.7	N/A
North-Korea	25240	26970	10.2	N/A
Total	*1611802*	*1569206*	*6611.4*	*10408*
(Notes)	decrease of 3%			

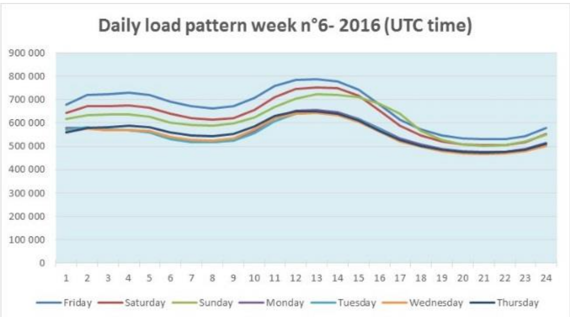
Source: World Population Prospects United Nations, 2015, IEA statistics, CIGRE C1.35.

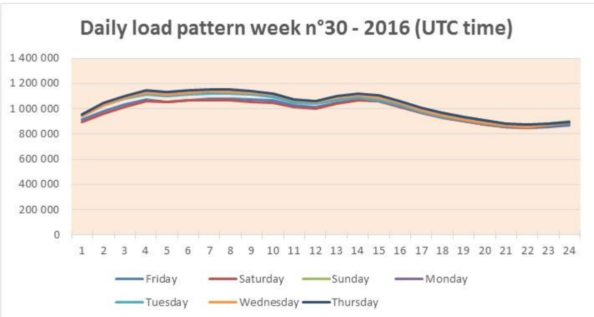
Electricity Demand Patterns

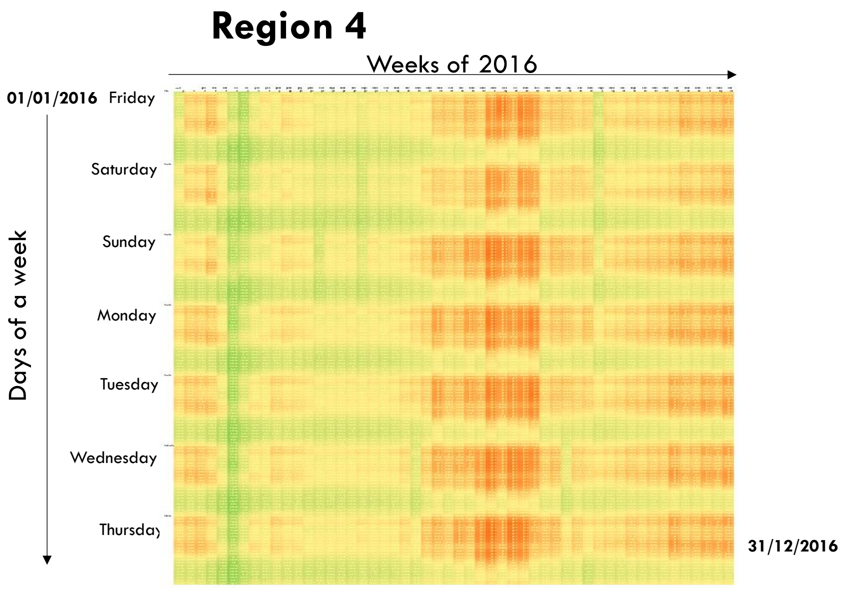




Source: CIGRE C1.35 survey. Peak period occurring in summer (e.g., July, August). Off-peak period occurring during late winter (e.g., Feb). Average value over the year = 850 GW, Max = +35%, min = -44%







Electricity Generation and Installed Capacities

Technology	2010		2050 (WEC – Unfinished Symphony)		2050 (C1.35)	
	Generation (TWh)	Installed Capacity (GW)	Generation (TWh)	Installed Capacity (GW)	Generation (TWh)	Installed Capacity (GW)
Hydro	840	300	1653	537	1633	420
Wind	120	80	931	372	285	166
Solar	0	0	1857	1129	1632	1183
Geothermal	0	0	0			
Biomass		0	245	82	36	17
Coal	3850	750	378	90	254	32
Oil	140	40				
Nuclear	600	110	2524	283	2687	318
Natural Gas	550	130	2331	742	3881	970
Total	*6100*	*1410*	*9920*	*3236*	*10408*	*3106*

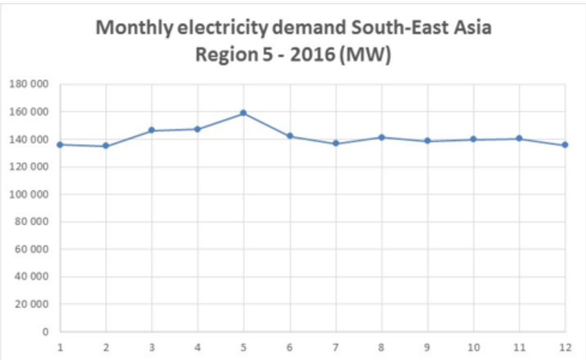
Source: World Energy Council 2013, 2016; CIGRE C1.35.

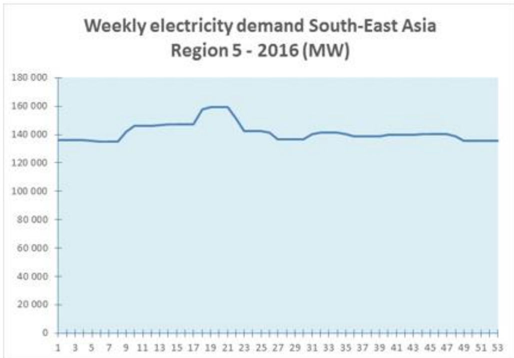
Region 5 – South-East Asia

Country	Population (thousands)		Electricity Demand (TWh)	
	2015	2050	2015	2050
Brunei	423	546	3.9	N/A
Cambodia	15578	22545	4.9	N/A
Indonesia	257564	322237	202.8	N/A
Laos	6802	10172	N/A	N/A
Malaysia	30331	40725	132.5	N/A
Myanmar	53897	63575	13.4	N/A
Philippines	100699	148260	67.8	N/A
Singapore	5604	6681	47.5	N/A
Thailand	67959	62452	174.8	N/A
Timor-Leste	1185	2162	N/A	N/A
Vietnam	93448	112783	143.4	N/A
Total	*633490*	*792138*	*790*	*1730*
(Notes)	increase of 25%			

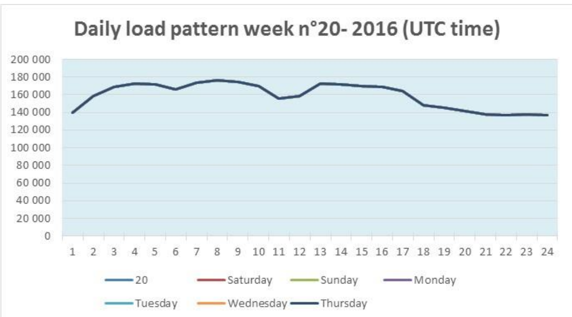
Source: World Population Prospects United Nations, 2015, IEA statistics, CIGRE C1.35.

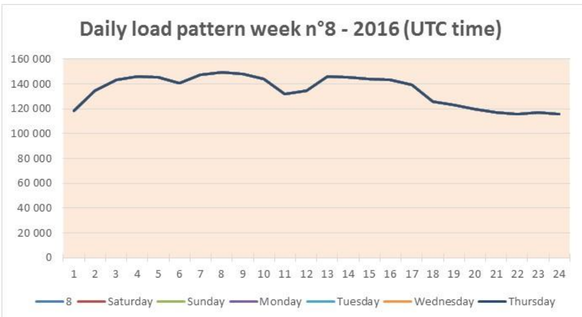
Electricity Demand Patterns

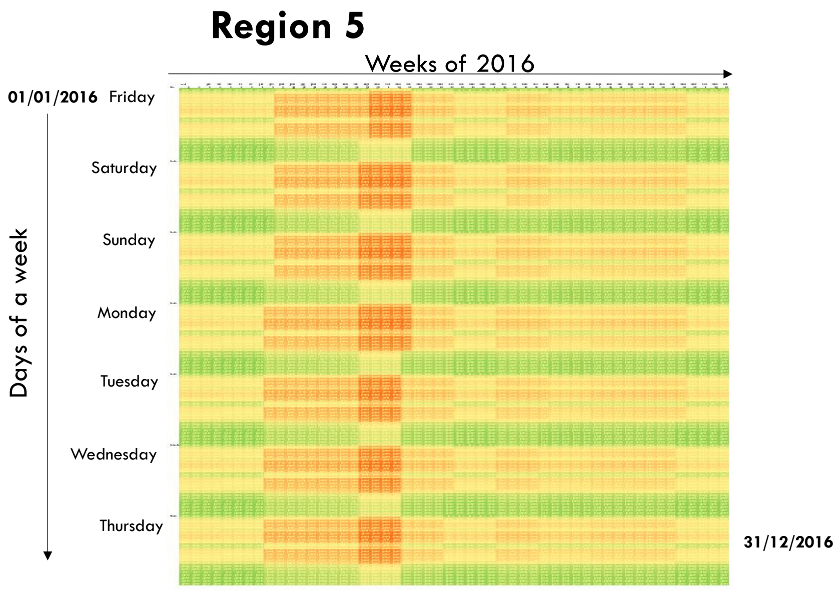




Source: CIGRE C1.35 survey.







Electricity Generation and Installed Capacities

Technology	2010 Generation (TWh)	2010 Installed Capacity (GW)	2050 (WEC – Unfinished Symphony) Generation (TWh)	2050 (WEC – Unfinished Symphony) Installed Capacity (GW)	2050 (C1.35) Generation (TWh)	2050 (C1.35) Installed Capacity (GW)
Hydro	83	23	237	55	236	78
Wind	13	7	124	62	598	246
Solar	0	13	421	223	343	233
Geothermal	20	3	104	0		
Biomass	0	0	71	22	14	7
Coal	247	23	88	16	59	8
Oil	53	17	0	0		
Nuclear	0	0	113	19	114	15
Natural Gas	250	60	533	150	496	177
Total	*667*	*147*	*1691*	*547*	*1860*	*763*

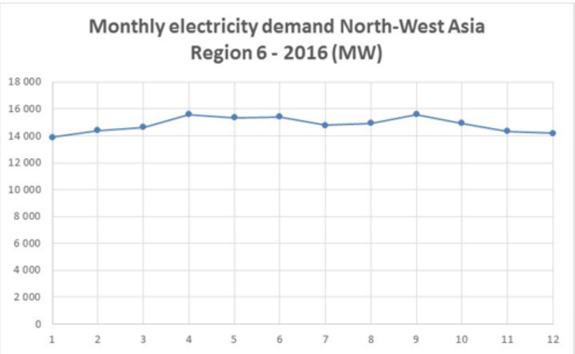
Source: World Energy Council 2013, 2016; CIGRE C1.35.

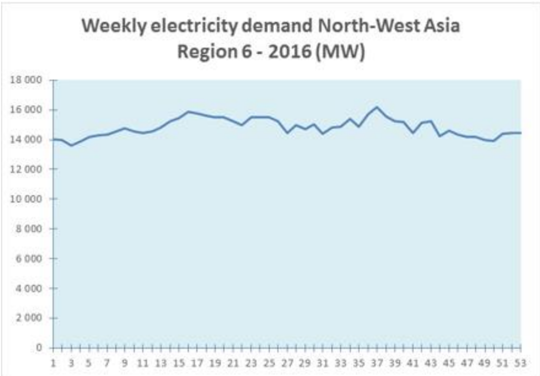
Region 6 – North-West Asia

Country	Population (thousands)		Electricity Demand (TWh)	
	2015	**2050**	**2015**	**2050**
Afghanistan	32527	55955	5	N/A
Azerbaijan	9754	10963	17.6	N/A
Kazakhstan	17625	22447	68.2	N/A
Kyrgyzstan	5940	8248	10.6	N/A
Tajikistan	8482	14288	12.4	N/A
Turkmenistan	5374	6555	12.4	N/A
Uzbekistan	29893	37126	46.5	N/A
Total	*109595*	*155582*	*172.7*	*551*
(Notes)				

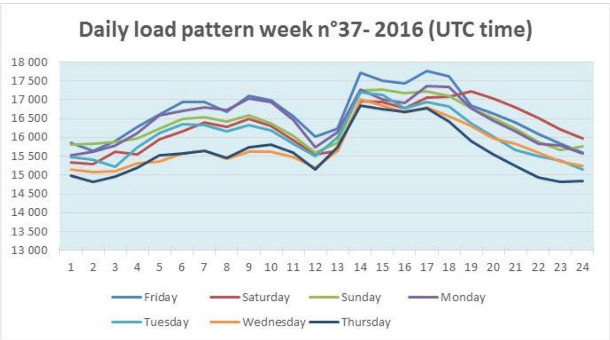
Source: World Population Prospects United Nations, 2015, IEA statistics, CIGRE C1.35.

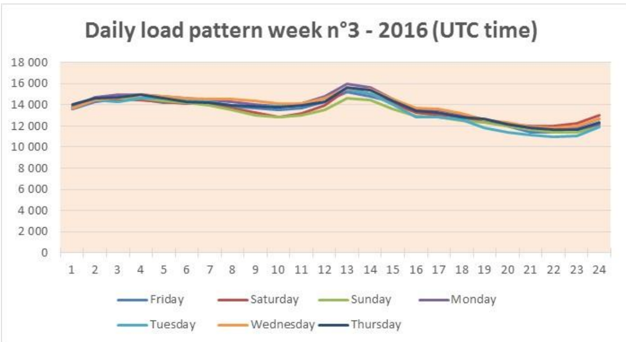
Electricity Demand Patterns

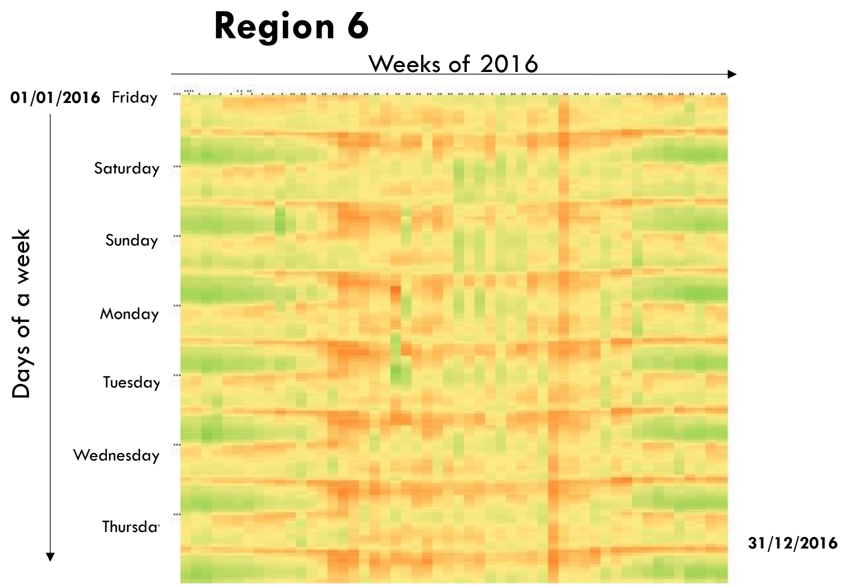




Source: CIGRE C1.35 survey.







Electricity Generation and Installed Capacities

Technology	2010		2050 (WEC – Unfinished Symphony)		2050 (C1.35)	
	Generation (TWh)	Installed Capacity (GW)	Generation (TWh)	Installed Capacity (GW)	Generation (TWh)	Installed Capacity (GW)
Hydro	40	8	145	48	71	21
Wind	5	4	186	81	261	69
Solar	10	5	248	149	56	49
Geothermal		0	30	0		
Biomass		0	70	10	6	3
Coal		11	40	6	14	3
Oil	5	6	0			
Nuclear		0	0	0	33	5
Natural Gas	30	7	101	20	109	48
Total	*90*	*40*	*820*	*313*	*551*	*198*

Source: World Energy Council 2013, 2016; CIGRE C1.35.

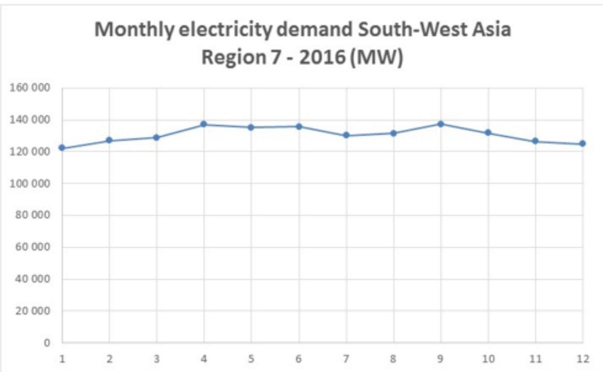
Region 7 – South Asia

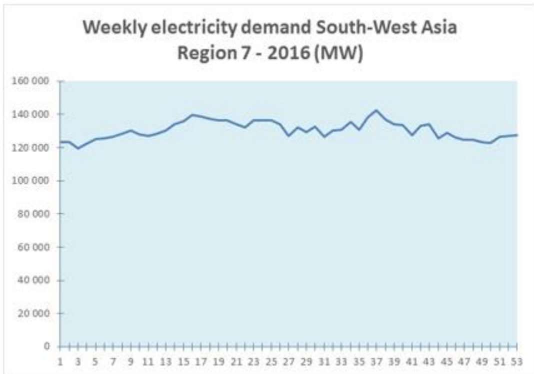
Country	Population (thousands)		Electricity Demand (TWh)	
	2015	**2050**	**2015**	**2050**
Bangladesh	160966	202209	48.6	N/A
Bhutan	775	950		N/A
India	1311051	1705333	1027	N/A
Maldives	364	494		N/A
Nepal	28514	36159	3.9	N/A
Pakistan	188925	309640	88.9	N/A
Sri-Lanka	20715	20836	11.7	N/A
Total	*1711310*	*2275621*	*1180.1*	*4885*

(Notes)

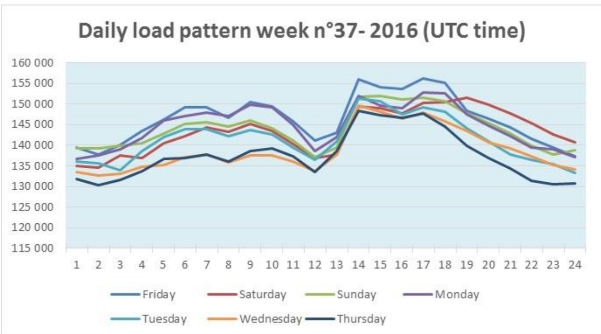
Source: World Population Prospects United Nations, 2015, IEA statistics, CIGRE C1.35.

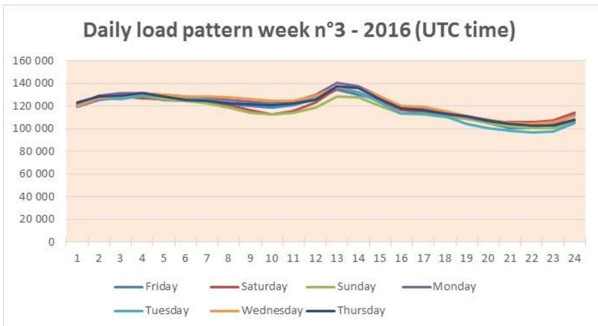
Electricity Demand Patterns

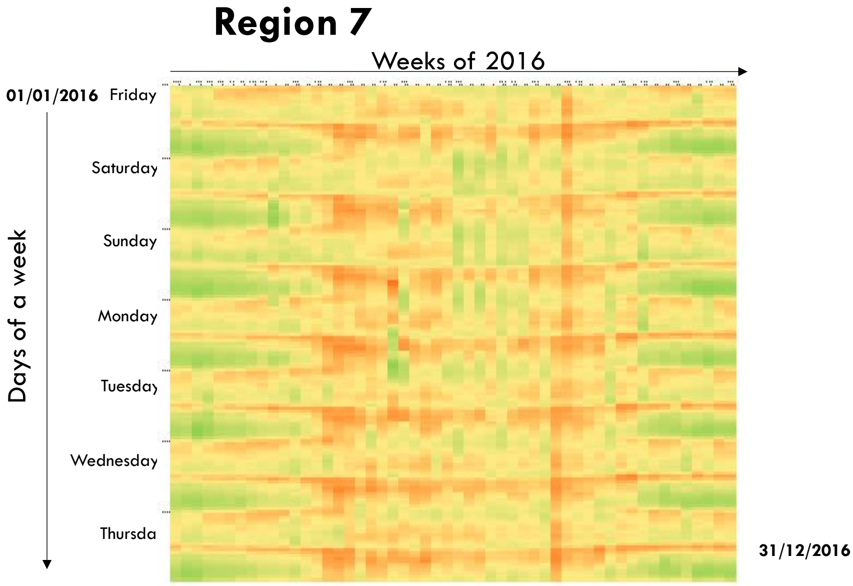




Source: CIGRE C1.35 survey.







Electricity Generation and Installed Capacities

	2010		2050 (WEC – Unfinished Symphony)		2050 (C1.35)	
Technology	Generation (TWh)	Installed Capacity (GW)	Generation (TWh)	Installed Capacity (GW)	Generation (TWh)	Installed Capacity (GW)
Hydro	160	32	582	192	638	127
Wind	35	26	1304	570	65	34
Solar	20	10	495	297	1 087	657
Geothermal	0		66	0		
Biomass	0		199	27	61	27
Coal	645	109	342	48	159	20
Oil	57	24	0			
Nuclear	50	5	433	94	366	45
Natural Gas	223	43	726	140	2 510	502
Total	*1190*	*250*	*4147*	*1369*	*4 885*	*1 413*

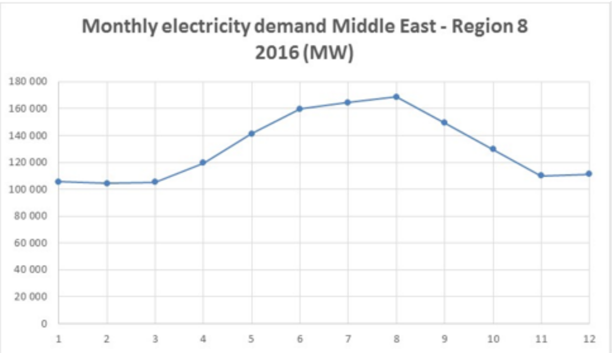
Source: World Energy Council 2013, 2016; CIGRE C1.35.

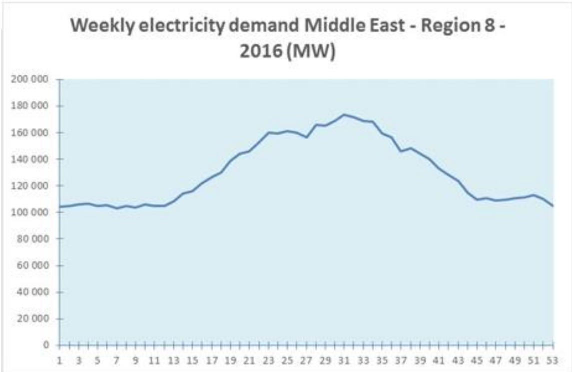
Region 8 – Middle-East

Country	Population (thousands)		Electricity Demand (TWh)	
	2015	**2050**	**2015**	**2050**
Georgia	4000	3483	9.9	N/A
Turkey	78666	95819	214.8	N/A
Bahrain	1377	1822	27.8	N/A
Iran	79109	92219	211	N/A
Iraq	36423	83652	35.6	N/A
Israel	8064	12610	54.4	N/A
Jordan	7595	11717	16.1	N/A
Kuwait	3892	5924	43.3	N/A
Lebanon	5851	5610	16.6	N/A
Oman	4491	5844	28.9	N/A
Qatar	2235	3205	36.4	N/A
Saudi Arabia	31540	46059	292.8	N/A
Syria	18502	34902	12.9	N/A
UAE	9157	12789	111.1	N/A
Yemen	26832	47170	3.1	N/A
Azerbaijan	9754	10963	17.6	N/A
Total	*327488*	*473788*	*1132.3*	*2215*
(Notes)				

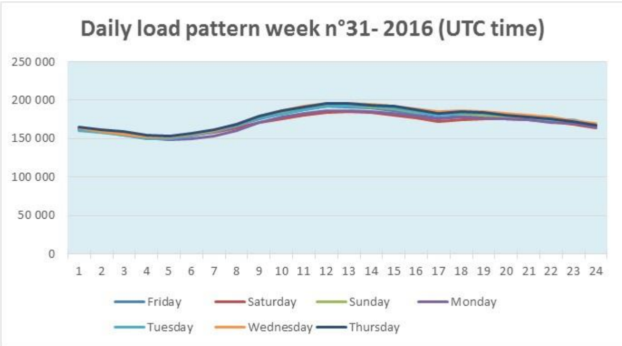
Source: World Population Prospects United Nations, 2015, IEA statistics, CIGRE C1.35.

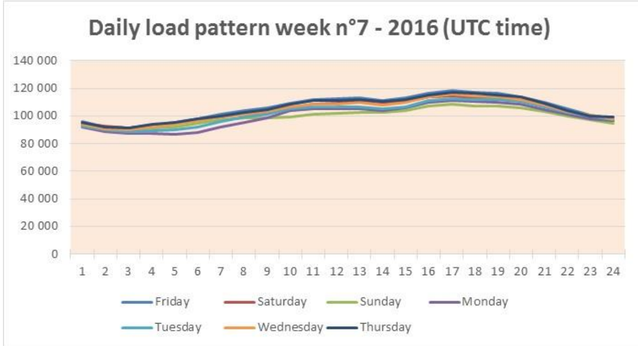
Electricity Demand Patterns

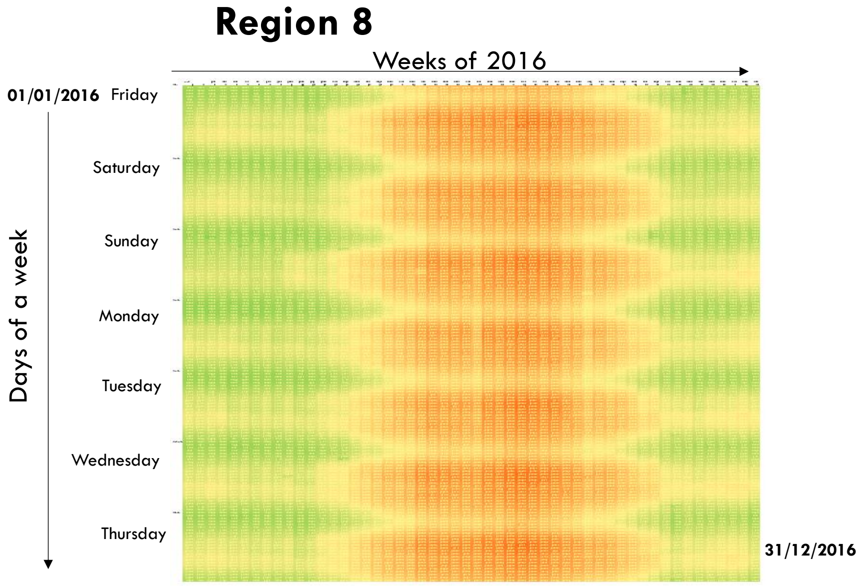




Source: CIGRE C1.35 survey. Peak period during summer (e.g., June, July, August). Off-peak during winter/spring (e.g., December to March). Average value = 130 GW, Max = +35%, min = - 22%.







Electricity Generation and Installed Capacities

Technology	2010		2050 (WEC – Unfinished Symphony)		2050 (C1.35)	
	Generation (TWh)	Installed Capacity (GW)	Generation (TWh)	Installed Capacity (GW)	Generation (TWh)	Installed Capacity (GW)
Hydro	85	34	145	48	29	5
Wind	3	1	186	81	1 128	412
Solar	0.1		248	149	420	267
Geothermal	0.6		30	0		
Biomass	0.2		70	10	56	25
Coal	90	4	40	6	18	3
Oil	290	70	0			
Nuclear	2.5	1	0	0	195	30
Natural Gas	570	110	101	20	369	239
Total	*1041*	*220*	*820*	*313*	*2 215*	*982*

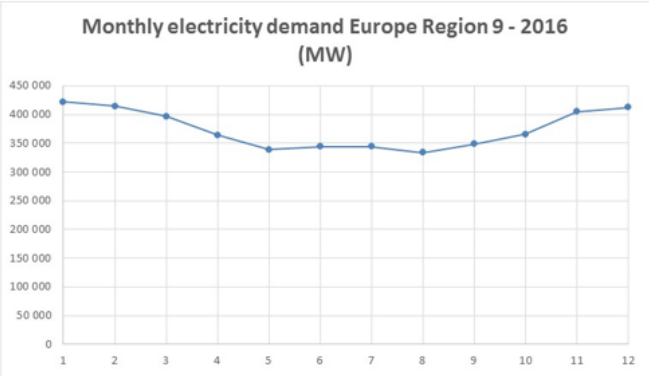
Source: World Energy Council 2013, 2016; CIGRE C1.35.

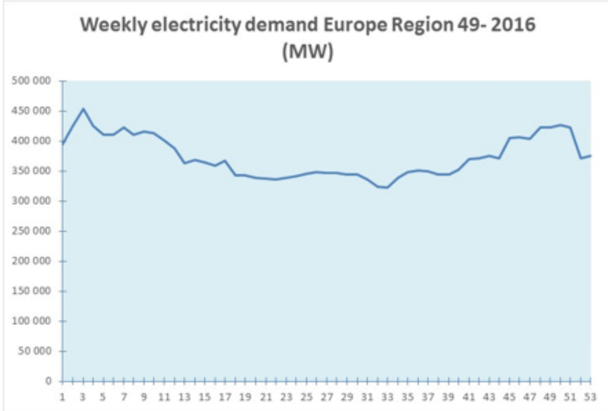
Region 9 – Europe

Country	Population (thousands)		Electricity Demand (TWh)	
	2015	2050	2015	2050
Albania	2897	2710	2.3	N/A
Austria	8545	8846	69.6	N/A
Belgium	11299	12527	85	N/A
Bosnia&Herzegovina	3810	3069	12	N/A
Bulgaria	7150	5154	33.2	N/A
Croatia	4240	3554	17	N/A
Cyprus	1165	1402	4.4	N/A
Czech Republic	10543	9965	63.4	N/A
Denmark	5669	6299	32.4	N/A
Estonia	1313	1129	8.1	N/A
Finland	5503	5752	82.5	N/A
France	64395	71137	475.4	N/A
Germany	80689	74513	520.6	N/A
Greece	10955	9705	51.2	N/A
Hungary	9855	8318	40.8	N/A
Ireland	4688	5789	27	N/A
Italy	59798	56513	314.3	N/A
Latvia	1971	1593	7.2	N/A
Lithuania	2878	2375	10.9	N/A
Luxembourg	567	803	6.4	N/A
Malta	419	411	3.4	N/A
Montenegro	626	574	7.4	N/A
Netherlands	16925	17602	112.5	N/A
Norway	5211	6658	128.3	N/A
Poland	38612	33136	151.1	N/A
Portugal	10350	9216	49	N/A
Romania	19511	15207	54.8	N/A
Serbia	8851	7331	39.3	N/A
Slovakia	5426	4892	27.2	N/A
Slovenia	2068	1942	13.6	N/A
Spain	46122	44840	262.9	N/A
Sweden	9779	11881	135.9	N/A
Switzerland	8299	10019	63.4	N/A
United Kingdom	64716	75361	340.2	N/A
Total	534845	530223	2955	4481
(Notes)				

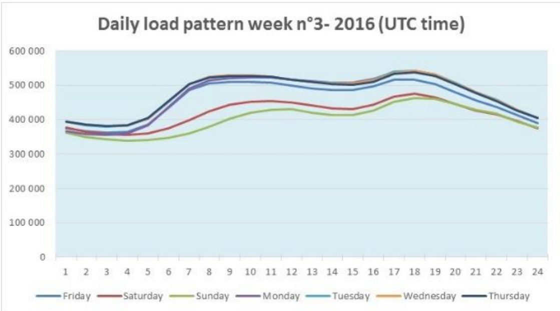
Source: World Population Prospects United Nations, 2015, IEA statistics, CIGRE C1.35.

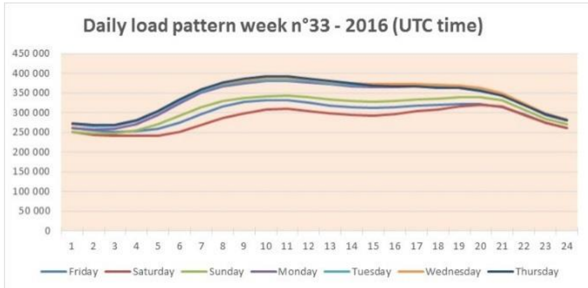
Electricity Demand Patterns

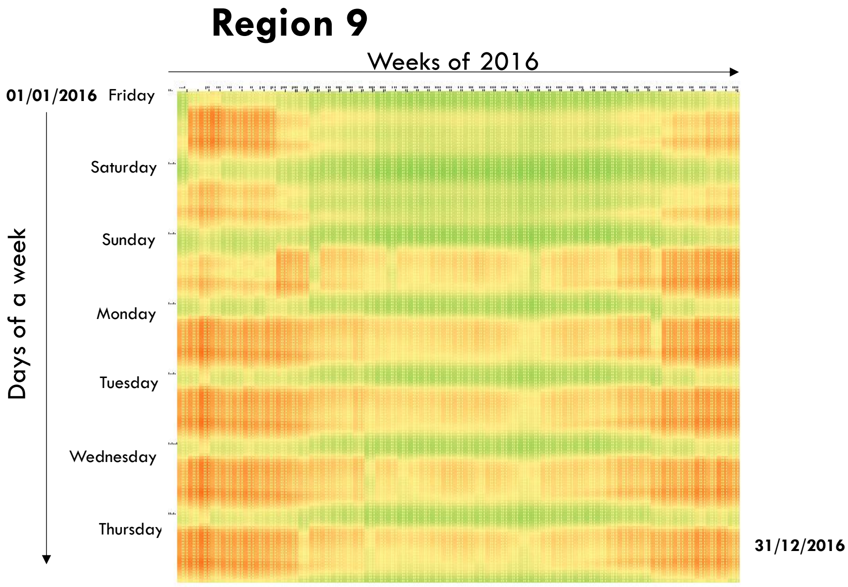




Source: CIGRE C1.35 survey. Peak period during winter (e.g., December to February). Off-peak during summer (e.g., June to August). Average value = 374 GW, Max = +21%, min = - 14%







Electricity Generation and Installed Capacities

	2010	2050 (WEC – Unfinished Symphony)	2050 (C1.35)

Technology	Generation (TWh)	Installed Capacity (GW)	Generation (TWh)	Installed Capacity (GW)	Generation (TWh)	Installed Capacity (GW)
Hydro	651	158	805	237	740	300
Wind	150	89	1758	676	760	314
Solar	20	50	308	213	365	300
Geothermal	29	2	28	0		
Biomass	148	37	432	72	116	50
Coal	964	236	177	29	220	30
Oil	69	90	0	0		
Nuclear	971	153	1245	170	1508	180
Natural Gas	860	290	767	164	771	360
Total	*3862*	*1105*	*5520*	*1561*	*4481*	*1534*

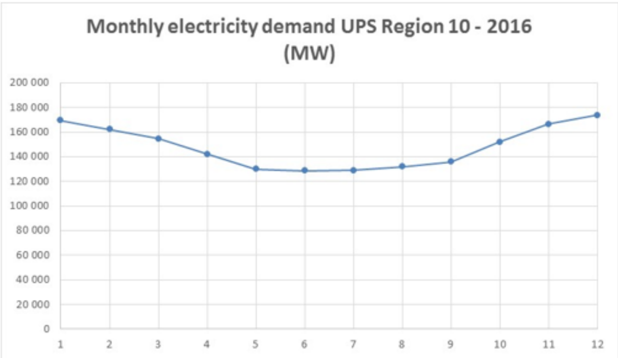
Source: World Energy Council 2013, 2016; CIGRE C1.35.

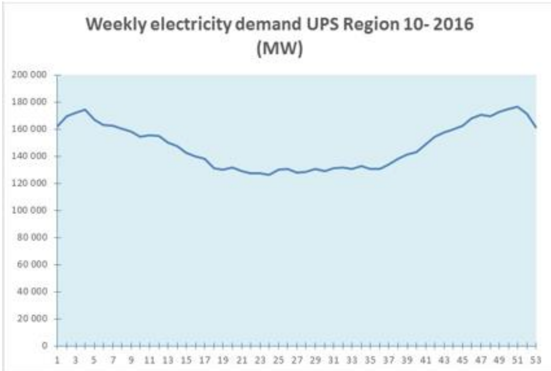
Region 10 – UPS

Country	Population (thousands)		Electricity Demand (TWh)	
	2015	2050	2015	2050
Belarus	9496	8125	29.2	N/A
Russia	143457	128599	726.3	N/A
Ukraine	44824	35117	118.9	N/A
Total	*197777*	*171841*	*874.4*	*2108*
(Notes)	decrease of 13%			

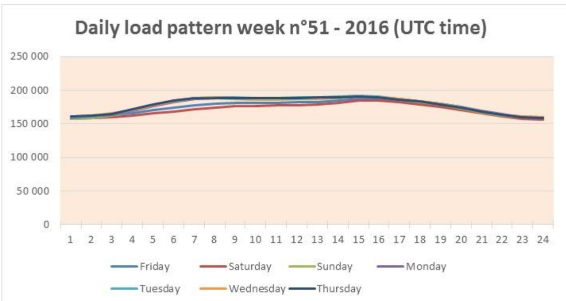
Source: World Population Prospects United Nations, 2015, IEA statistics, CIGRE C1.35.

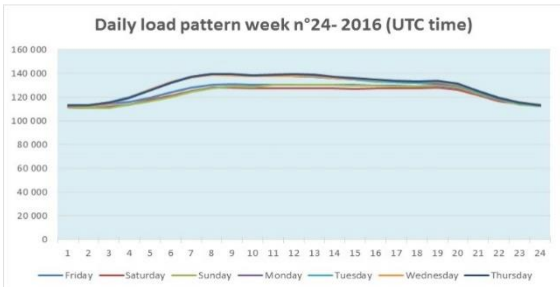
Electricity Demand Patterns

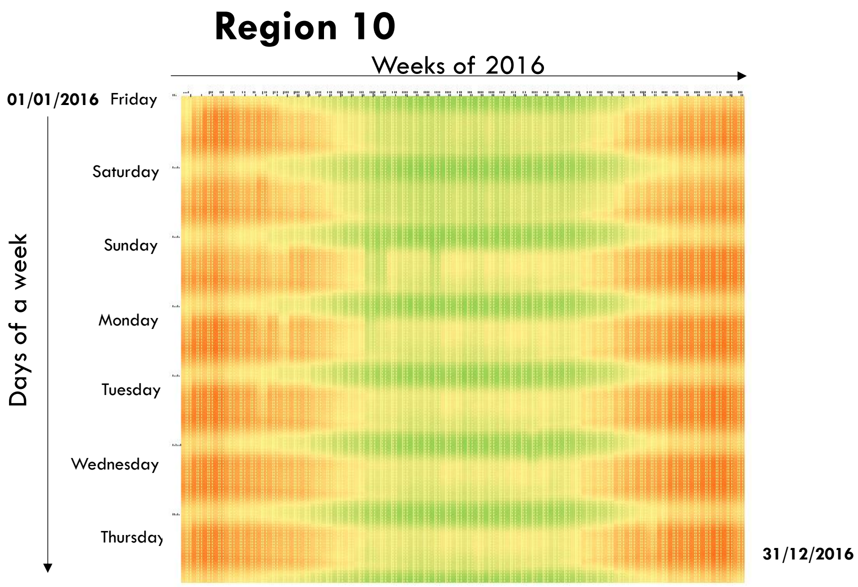




Source: CIGRE C1.35 survey. Peak period during winter (January, December). Off-peak during summer (e.g., June to August). Average value = 148 GW, Max = +20%, min = - 15%.







Electricity Generation and Installed Capacities

Technology	2010		2050 (WEC – Unfinished Symphony)		2050 (C1.35)	
	Generation (TWh)	Installed Capacity (GW)	Generation (TWh)	Installed Capacity (GW)	Generation (TWh)	Installed Capacity (GW)
Hydro	179	52	261	77	348	166
Wind	0	1	570	218	335	162
Solar	0	0	100	69	65	61
Geothermal	1	1	8	0		
Biomass	2	0	139	24	55	23
Coal	236	14	57	9	112	13
Oil	11	0	0	0		
Nuclear	259	37	403	56	692	80
Natural Gas	570	60	248	53	500	139
Total	*1258*	*165*	*1788*	*505*	*2108*	*644*

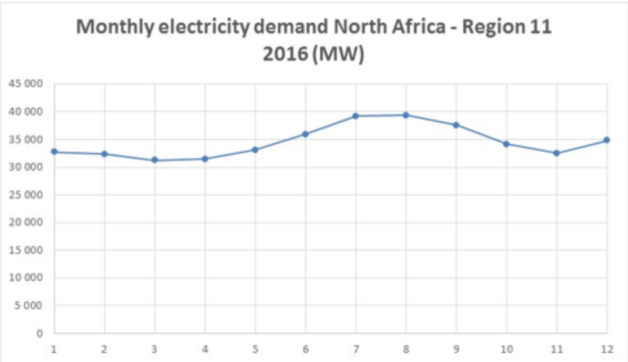
Source: World Energy Council 2013, 2016; CIGRE C1.35.

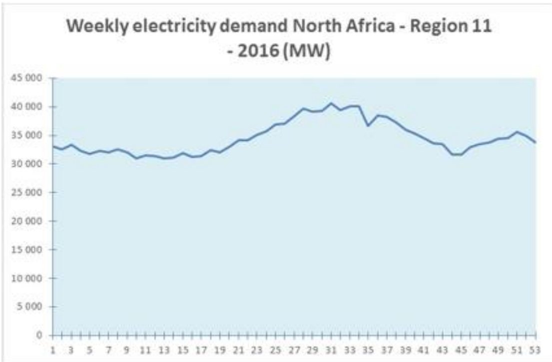
Region 11 – North Africa

Country	Population (thousands)		Electricity Demand (TWh)	
	2015	**2050**	**2015**	**2050**
Algeria	39667	56461	50.1	N/A
Egypt	91508	151111	154.2	N/A
Libya	6278	8371	9.8	N/A
Morocco	34378	43696	29.9	N/A
Tunisia	11254	13476	14.4	N/A
Israel	8064	12610	54.4	N/A
Western Sahara	573	901		N/A
Sudan	40235	80284	10.6	N/A
Total	*231957*	*366910*	*323.4*	*513*
(Notes)	increase of 58%			

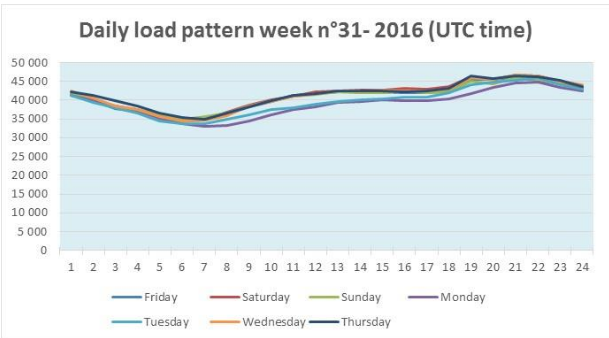
Source: World Population Prospects United Nations, 2015, IEA statistics, CIGRE C1.35.

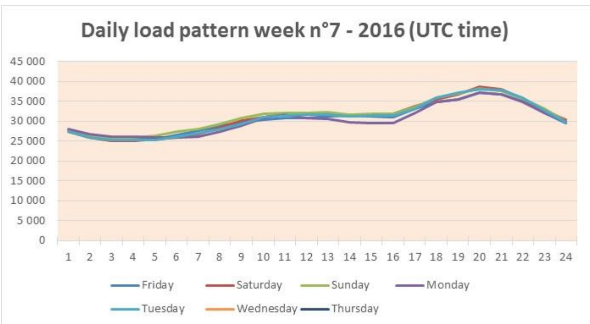
Electricity Demand Patterns

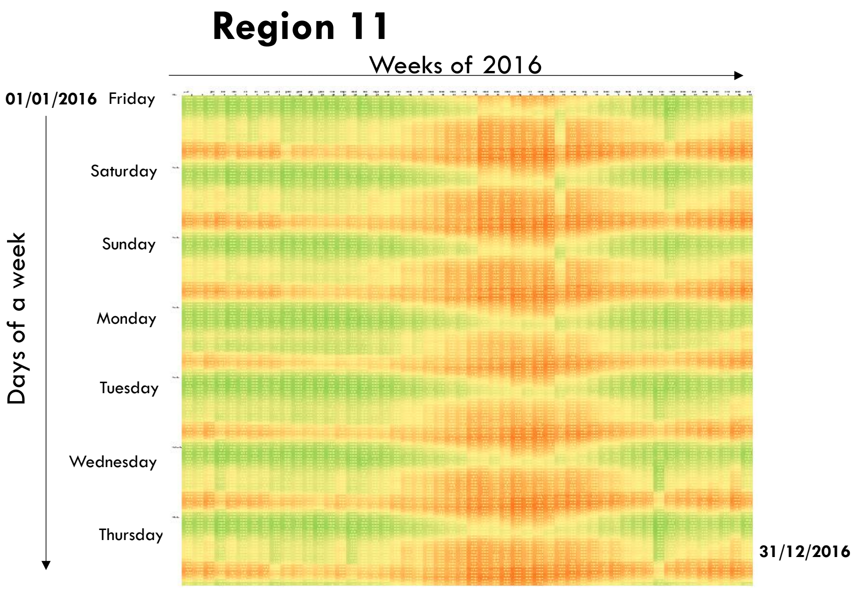




Source: CIGRE C1.35 survey. Peak period during summer (e.g., July, August). Off-peak during winter/spring (e.g., November to April). Average value = 35 GW, Max = +17%, min = - 17%.







Electricity Generation and Installed Capacities

Technology	2010		2050 (WEC – Unfinished Symphony)		2050 (C1.35)	
	Generation (TWh)	Installed Capacity (GW)	Generation (TWh)	Installed Capacity (GW)	Generation (TWh)	Installed Capacity (GW)
Hydro	15	4	14	4	7	2
Wind	3	1	52	4	276	92
Solar	0,2		119	65	120	67
Geothermal	0		0	0		
Biomass	0		0	0	14	6
Coal	10	1	2	0	4	1
Oil	40	10	21	0		
Nuclear	0	0	0	0	47	8
Natural Gas	190	35	338	82	83	55
Total	*258*	*51*	*547*	*155*	*552*	*231*

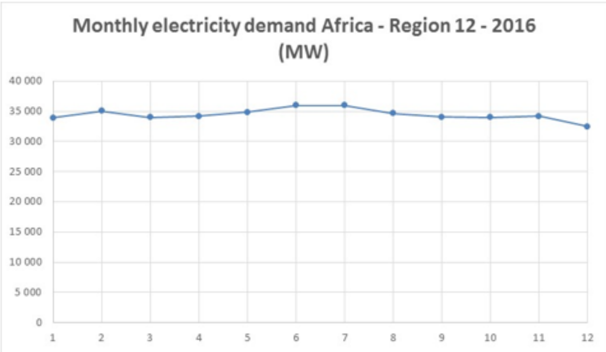
Source: World Energy Council 2013, 2016; CIGRE C1.35.

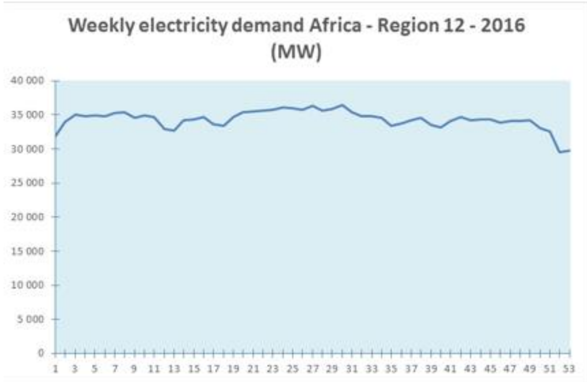
Region 12 – Africa

Country	Population (thousands)		Electricity Demand (TWh)	
	2015	2050	2015	2050
Angola	25002	65473	8.4	N/A
Benin	10880	22549	1.1	N/A
Botswana	2262	3389	3.5	N/A
Cameroon	23344	48362	5.8	N/A
Central African Republic	4900	8782	N/A	N/A
Cote d'Ivoire	22702	48797	6	N/A
Chad	14037	35131		N/A
RDC	77267	195277	7.3	N/A
Equatorial Guinea	845	1816		N/A
Ethiopia	99391	188455	8.3	N/A
Gabon	1725	3164	1.8	N/A
Gambia	1991	4981		N/A
Ghana	27410	50071	8.6	N/A
Kenya	46050	95505	7.9	N/A
Lesotho	2135	2987	N/A	N/A
Liberia	4503	9436	N/A	N/A
Malawi	17215	43155	N/A	N/A
Mali	17600	45404	N/A	N/A
Mauritania	4068	8049	N/A	N/A
Mozambique	27978	65544	13.4	N/A
Namibia	2459	4322	3.8	N/A
Niger	19899	72238	0.9	N/A
Nigeria	182202	398508	25	N/A
Congo	4602	10732	0.8	N/A
Senegal	15129	36223	3.4	N/A
South Africa	54490	65540	198.5	N/A
Swaziland	1287	1792	N/A	N/A
Tanzania	53880	137000	3.9	N/A
Togo	7305	15681	1.2	N/A
Uganda	39 032	101 873	2.7	N/A
Zambia	16212	42975	11.4	N/A
Zimbabwe	15603	29615	6.8	N/A
Total	*843405*	*1862826*	*330.5*	*2427*
(Notes)	Increase of 116%			

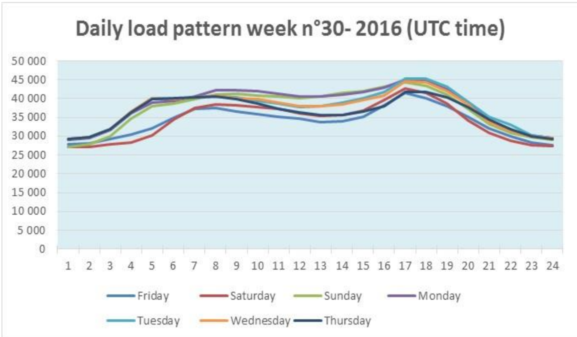
Source: World Population Prospects United Nations, 2015, IEA statistics, CIGRE C1.35.

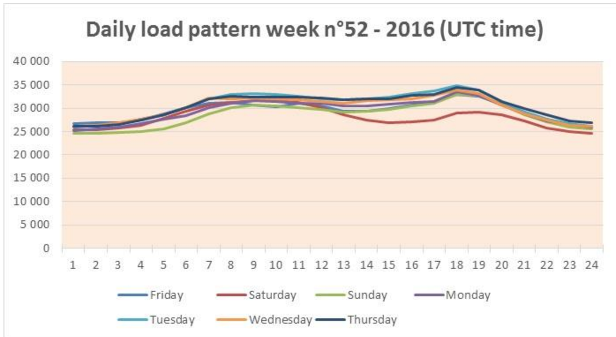
Electricity Demand Patterns

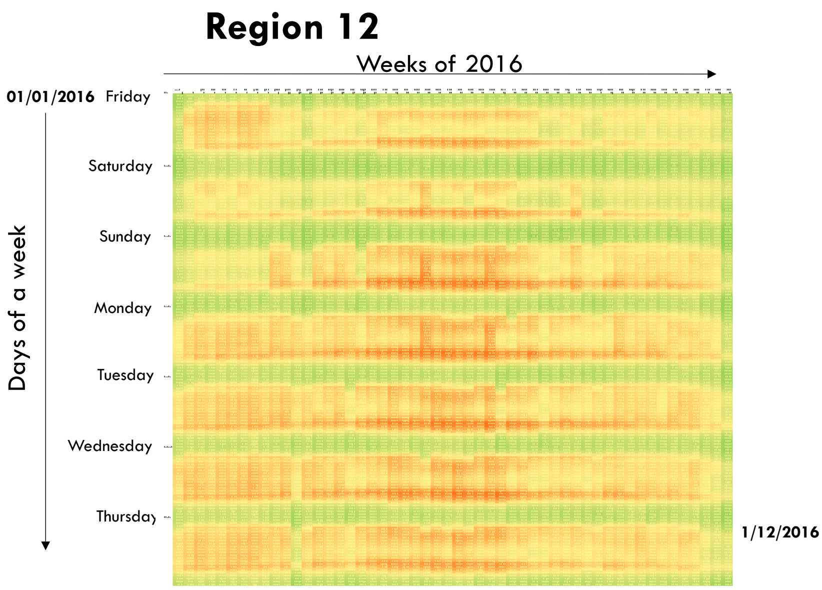




Source: CIGRE C1.35 survey.





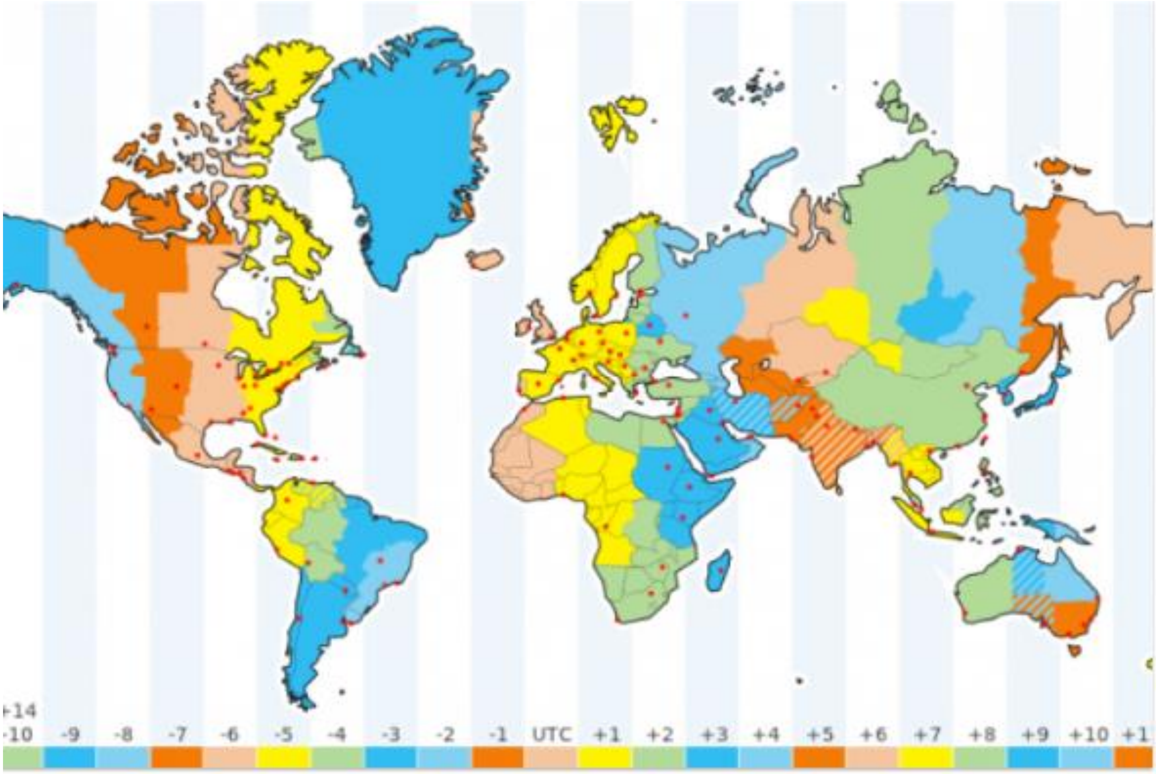


Electricity Generation and Installed Capacities

Technology	**2010**		**2050 (WEC – Unfinished Symphony)**		**2050 (C1.35)**	
	Generation (TWh)	Installed Capacity (GW)	Generation (TWh)	Installed Capacity (GW)	Generation (TWh)	Installed Capacity (GW)
Hydro	85	18	446	95	424	99
Wind	15	2	223	84	921	284
Solar			490	260	398	239
Geothermal			120			
Biomass			220	29	75	32
Coal	250	30	72	13	48	7
Oil	30	20				
Nuclear	15	5	57	9	56	8
Natural Gas	25	10	648	202	506	242
Total	*420*	*85*	*2276*	*692*	*2 427*	*912*

Source: World Energy Council 2013, 2016; CIGRE C1.35.

C.6. Time-zones



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