Smarter & Stronger Power Transmission: Review of feasible technologies for enhanced capacity and flexibility

ISGAN Discussion Paper
Annex 6 Power T&D Systems, Task 3 and 4 August 2013
ISGAN Discussion Paper
Annex 6 Power T&D Systems, Task 3 and 4

MSc E.E. Carl Öhlén Operating Agent for Annex 6 Power T&D Systems and Leader for task 3 on Technology Development and Demonstration; Swedish Transmission Research Institute (STRI) – Sweden / Carl.ohlen@stri.se

Professor Kjetil Uhlen member of ISGAN Annex 6 Power T&D Systems and Leader for task 4 on System Operation Management and Security; Norwegian University of Science and Technology (NTNU), Department of Electric Power Engineering – Norway / Kjetil.Uhlen@ntnu.no

Abstract: Transmission and distribution (T&D) systems are facing new challenges linked with the introduction in the generation mix of a progressively increasing share of unpredictable energy sources and variable generation from renewable energy sources (RES), as well as changing patterns of demand that new types of load such as electric vehicles (EV) will introduce. Large and unpredictable fluctuations in the power balance as well as variations in voltage can jeopardize the quality and availability of power. The T&D system has to be stronger and smarter to provide the real-time flexibility needed to efficiently handle the new conditions. Investment needs in the power T&D infrastructure are large and require long term planning and deployment. The environmental concerns and public acceptance issues that often arise when constructing additional conventional transmission lines will require more efficient solutions with lower environmental impact.

This Discussion Paper from ISGAN Annex 6 Power Transmission & Distribution Systems Task 3 and 4 focuses on “Smarter & Stronger Power Transmission” and is a review of feasible technologies for enhanced transmission capacity and flexibility in terms of status and deployment. This includes both the primary AC and DC technology for the high voltage transmission grid as well as the information and communication technology (ICT) required to efficiently supervise and operate the power system. Focus is on the development of power electronics including flexible AC transmission (FACTS) and high voltage DC (HVDC), the standardization within ICT such as IEC 61850 and Common Information Model (CIM) in order to obtain vendor independent interoperability as well as the progress of wide area monitoring, protection and control (WAMPAC). The combination of smarter ICT applications together with power electronics such as FACTS and HVDC can be described as a digitalization of the power system operation offering the required flexibility. Most of the examples given are from the Nordic European power system, reflecting the participation of the authors from ISGAN Annex 6 Task 3 and 4, with additional input from North America and selected International case studies.
About ISGAN Discussion Papers: ISGAN Discussion Papers are meant as input documents to the global discourse about smart grids. Each is a statement by the author(s) regarding a topic of international interest. They reflect works in progress in the development of smart grids in the different regions of the world. Their aim is not to communicate a final outcome or to advise decision-makers, rather to lay the ground work for further research and analysis.

Acknowledgements: This Discussion Paper was prepared during Q1, 2013 by the task leaders for ISGAN 6 Power T&D Systems, Carl Ohlen (Task 3) and Kjetil Uhlen (Task 4). The Authors used information and knowledge from the Swedish and Norwegian ISGAN Annex 6 technical experts and could benefit from their direct experience in Smart Grid projects, the International Electrotechnical Commission (IEC), the Council on Large Electric Systems (CIGRE) and other initiatives. This combined expertise is documented in three Special Reports from ISGAN Annex 6 Task 3, dealing with Technology Development and Demonstration.

This report is mainly based on the development and case studies from Norway and Sweden. Additional information was also used from the work of the Authors and other technical experts involved.

FACTS and HVDC technologies were first introduced in Sweden during the 1950s, and supplemented by a national “Internet-like” communication (TIDAS) for remote control which was introduced in the 1970s. Both developments contributed to the evolution of the Nordic power system towards one of the first multinational deregulated markets.

Comprehensive data from studies, projects and products have been gathered by ISGAN technical experts in Norway and Sweden. This paper includes detailed information from selected case studies. Part of the material has been produced by the Company ABB, who introduced some of these technologies and can claim a long global operational experience with FACTS, HVDC and substation automation technologies. It is however important to highlight that ABB is nowadays only one of the many technology providers in this field: other international companies such as Alstom Grid and Siemens, as well as local suppliers, like CEPRi in China, already have or are developing power electronics technologies as UHVDC and HVDC-VSC. The same is valid for ICT and power utility automation, both of which have a very long list of technology suppliers.

As this “digital power system” technology is now being deployed globally, this report focuses especially on interoperability among products and systems from diverse vendors as a fundamental challenge for creating a Smart and Strong Grid. Therefore, the paper refers to available work and reports from CIGRE, IEC, the National Institute of Standards and Technology (NIST), the European Network for Transmission System Operators for Electricity (ENTSO-E) and the European Committee for Electrotechnical Standardization (CENELEC), along with ongoing joint industry initiatives. This Discussion Paper also draws on earlier work within International Energy Agency (IEA) Implementing Agreement on Electricity Networks, Analysis, Research and Development (ENARD), as well as ongoing work within ISGAN Annex 6 (with its participants during 2012 from Austria, Belgium, Italy, Norway, Sweden and the United States), which includes conclusions arising from several ISGAN Annex 6 workshops held in 2012 and 2013. Finally, the work within the US Department of Energy (US DOE) on Transmission Systems and the North American Synchrophasor Initiative (NASPI) project has been a valuable contribution through ISGAN Annex 6 Task 1 Leader Phil Overholt. Specific references are listed separately.

The paper’s Executive Summary was edited by Marilyn Smith.

Disclaimer: This publication was prepared for ISGAN. ISGAN, also known as the IEA Implementing Agreement for a Co-operative Programme on Smart Grids (ISGAN), functions within a framework created by the International Energy Agency (IEA). The views, findings and opinions expressed herein do not necessarily state or reflect those of any of ISGAN’s Participants, any of their sponsoring governments or organizations, the IEA Secretariat, or any of its member countries. No warranty is expressed or implied, no legal liability or responsibility assumed for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, and no representation made that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring.
This Discussion Paper from ISGAN Annex 6 Power Transmission & Distribution Systems focuses on “Smarter & Stronger Power Transmission” and is a review of feasible technologies for enhanced transmission capacity and flexibility in terms of status and deployment. This includes both the primary AC and DC technology for the high voltage transmission grid as well as the Information and Communication Technology (ICT) required to efficiently supervising and operating the power system. Many examples given are from the Nordic European power system, which is a synchronized 50 Hz system connected to the rest of Europe with HVDC links as illustrated above.
# Contents

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 Executive Summary</td>
<td>P. 6</td>
</tr>
<tr>
<td>2 Introduction</td>
<td>P. 13</td>
</tr>
<tr>
<td>2.1 ISGAN Power T&amp;D Systems objectives</td>
<td></td>
</tr>
<tr>
<td>2.2 Conclusions from ENARD</td>
<td></td>
</tr>
<tr>
<td>3 Background and Overview</td>
<td>P. 15</td>
</tr>
<tr>
<td>3.1 A Framework for the Smart Grid</td>
<td></td>
</tr>
<tr>
<td>3.2 The Nordic Electrifying Experience</td>
<td></td>
</tr>
<tr>
<td>3.3 A Global View</td>
<td></td>
</tr>
<tr>
<td>4 Status of Feasible Transmission System Technologies &amp; Solutions</td>
<td>P. 29</td>
</tr>
<tr>
<td>4.1 HVAC and HVDC Power electronics</td>
<td></td>
</tr>
<tr>
<td>4.2 ICT for Network Management and Automation</td>
<td></td>
</tr>
<tr>
<td>4.3 Wide Area Monitoring, Protection and Control</td>
<td></td>
</tr>
<tr>
<td>5 Conclusions and Recommendations</td>
<td>P. 65</td>
</tr>
<tr>
<td>5.1 Deployment of smarter &amp; stronger transmission infrastructure</td>
<td></td>
</tr>
<tr>
<td>5.2 Ensuring interoperability for communication and automation</td>
<td></td>
</tr>
<tr>
<td>5.3 Enhancement of observability &amp; controllability with WAMPAC</td>
<td></td>
</tr>
<tr>
<td>6 List of HVDC VSC Projects</td>
<td>P. 76</td>
</tr>
<tr>
<td>7 References</td>
<td>P. 77</td>
</tr>
<tr>
<td>8 Acronyms and abbreviations</td>
<td>P. 79</td>
</tr>
</tbody>
</table>
1 Executive Summary

Power T&D systems are vital to clean energy deployment

THE FUTURE IS ELECTRIC!

Recognising that energy is vitally important for future economic growth, many countries are making it a priority to establish a clean and efficient energy system. Three main factors drive the share of electricity as a primary energy carrier:

- Increasing demand associated with global efforts to bring modern energy to the more than one billion people in the world who are currently without electricity and to many more with insufficient electricity supply, and from new applications for electrical power (such as computers, cell phones, electric vehicles, etc.).
- The urgent need to decarbonise the energy system through an increased use of renewable energy sources (RES) and other clean energy sources generating electricity.
- The need to reduce overall primary energy demand by making energy consumption more efficient; here, electricity offers smarter electrical solutions (such as heat pumps).

SMART & STRONG POWER SYSTEMS ARE NEEDED TO KEEP PACE WITH ELECTRICITY DEMAND!

Modern society depends heavily on the continuous delivery of reliable and efficient electric power to homes, offices, industries, shopping centres and transportation systems. To manage uncertainty and variability, increased electrification requires more intelligent operation of smarter and stronger power transmission and distribution (T&D) systems to:

- Connect large-scale RES (hydro, wind, solar) facilities from remote regions, link generation and consumption areas (such as offshore wind farms and growing of mega-cities) and integrate additional infrastructure for storage, balancing and reserves.
- Support installations of intermittent power generation from distributed energy resources (DER) based on solar and wind, as well as consumer demand response.
- Modernize and strengthen ageing T&D infrastructures in many countries to meet future challenges and ensure reliable power delivery.

WE NEED TO INVEST IN A SMART & STRONG GRID!

Figure 1. The smart and strong grid
BACK TO BASICS: A PRIMER FOR NON-EXPERTS

Understanding a few basic concepts will be useful to non-experts who participate in energy planning and decision-making.

When electricity became a part of society at the end of the 19th century, a “war of currents” quickly arose. Thomas Edison promoted an option known as direct current (DC), while Nicholas Tesla and George Westinghouse were proponents of alternating current (AC). Agreement was reached to standardize certain elements of the new technology, such that electric power ($P$) came to be measured in watts ($W$) and the two factors that determine power were designated as; current ($I$), which is measured in amperes; and voltage ($U$), measured as volts.

From the start, transporting electricity from the point of generation to that of use was a challenge as a portion of the power was lost along the way, due to electric resistance of the line. AC had the advantage that transformers could be used to increase the voltage in steps, thereby allowing power transmission over longer distances whereas DC was limited by the low voltage range allowed by generators and suitable only for shorter distances.

As a result, AC was adopted by other inventors such as Jonas Wenström, who patented a complete three-phase power system with generator, motor and transformer, which was tested 1890. A simplified three-phase AC power system can be seen as a generator supplying electricity to a motor at a defined frequency (normally is 50 Hz or 60 Hz). The generator produces active power ($P$), which the motor consumes: if the production is higher than the consumption, the frequency of the system will increase; if the production is lower, the frequency will decrease (Figure 2).

![Figure 2. A simplified power system shown in balance and out of balance](image)

In reality, such systems include a large number of generators and an even higher number of motors and other types of load that are “synchronized” and connected by the power T&D grid. Production and consumption for the complete system need to be in balance at any time, while also taking into account that losses will occur within the power T&D grid.

T&D losses result from the fact that the resistance ($R$) of a transmission line consumes active power ($P$), thereby reducing the voltage. Further reduction in the voltage is caused by inductance of the power line that introduces the reactance ($X$), which is higher than the resistance and consumes reactive power ($Q$).

AC transmission was further developed for higher voltages during the first half of the 20th century. In 1952, Sweden achieved an industrial first by introducing a 400 kV AC line; just two years later, the Swedes established the world’s first high voltage DC (HVDC) line, which provided a cable link spanning almost 1 000 km to the island of Gotland.
ENERGY BALANCING UNDER A NEW PARADIGM

By its very nature, electricity adds a complex dimension to energy delivery: because it cannot be stored, power companies need to anticipate—down to the minute—the level of demand (i.e. how much electricity will be needed by whom). In fact, the level of demand drives the amount of generation required, and meeting demand requires that a synchronized power system be continuously balanced both for active power (frequency) and reactive power (voltage). Unbalance between production and consumption may cause a power system to break apart. Moreover, the T&D grid is exposed to weather, vegetation, pollution, and other events that can create disturbances and faults (such as flashovers). Strategies to predict demand and manage balancing within traditional energy systems are well developed.

Energy systems are changing in ways that make old strategies obsolete. The introduction of renewable energy sources creates variability on two levels. First, the availability of the resource—sun, wind or hydro—is less predictable than using fossil fuels for a primary source. Second, rather than having one massive plant, many RES technologies are small scale and distributed over wide areas (such as wind or solar farms). A third factor that influences balancing is the possibility to influence the load patterns (i.e. actual electricity use) through demand-response mechanisms.

Instead of a long-term plan for a balanced power system with minor deviations from predictions, this new paradigm requires the ability to adapt rapidly to changes and large fluctuations throughout the power system. Larger numbers of new types of generation in multiple locations often means increased use of cables, which influences the reactive power balance and the voltage in different parts of the system.

In today’s more diversified yet integrated energy systems, there are critical locations at which a fault that is not cleared with sufficient rapidity may result in a major disturbance: one subsystem may accelerate while the other lags behind, creating a risk that the two systems will separate. The new system requires innovative mechanisms by which a short circuit fault can be instantaneously detected and disconnected by the protection and circuit breakers, respectively.

Thanks to the rapid development of power electronics, old applications with switched capacitors and reactors can be optimized with thyristors and transistors in what is known as flexible AC transmission systems (FACTS) and with HVDC. Wide area monitoring, protection and control (WAMPAC) can interact with available FACTS devices and HVDC. This creates increased flexibility to respond to sudden changes of active and reactive power flows in the system: in effect, “smarter” monitoring, protection and control systems are better able to act on “smarter” primary systems.

Several approaches have been developed to minimize losses on long transmission lines. Many power companies now install conductors with a larger cross section (to reduce resistance) and/or several (bundle) conductors per phase (to reduce reactance). Others use reactive power compensation, in which series capacitors provide negative reactance to compensate for the positive reactance from the inductance of the line. A third option is to install shunt capacitors at the end of the line to provide reactive power and increase the voltage, or shunt reactors to reduce the voltage.

With these advances, both types of systems have become widely used, often complementing each other. AC systems of 400 kV, 500 kV, 800 kV and 1 000 kV AC are in operation around the world, while HVDC transmission up to +/- 800 kV is used for many applications.
Since DC is not affected by reactance, HVDC is preferable for long-distance transmission and for longer offshore cable connections. DC can also be used to direct the power flow and act as a “switch” between different AC systems. Although the present applications of DC is to connect two terminals without any intermediate station, DC meshed networks are also discussed for the future smarter grid. The use of HVDC to separate two AC sub-systems, or as “embedded” HVDC, can improve the performance of existing HVAC systems. The evolution of power transistors replacing power thyristors paved the way for the new HVDC with voltage source converter (VSC) technology, which controls both active and reactive power. VSC is now in service in several applications around the world.

Historical data show power consumption and production for a typical week in Sweden (Figure 4). Because the pattern is predictable, it is quite simple to balance the system using nuclear power for base production (red) and hydro power (blue) together with import from other countries (grey) to balance the variations. Hydro power has the advantage that it can be stored (in reservoirs) and dispatched (run through the dam) when required, and can be used as a spinning reserve. In effect, the hydro station (the generator) is synchronized to the system without producing any power but ready for activation when needed.

With the introduction of more wind and solar power in the system, production is variable and more unpredictable (Figure 5). Thus, managing a given energy system becomes a more complex matter of balancing variation in both consumption and production. Based on the simple formula “Energy = Power x time”, because production from renewable energy sources has a lower capacity factor (i.e. lower capability to produce the rated power during time, because of the variability of the primary source) compared to conventional generation, it is necessary to install more power in MW to get the same amount of energy as MWh.
Under this new scenario, peak power production can be very high and theoretically equal to all connected RES, while there can also be periods of variable duration with practically no generation. It is important to note that RES is not completely unpredictable – and prediction methods are improving. While solar may have large variations during the day, it is more predictable than wind power since no solar generation occurs at night.

A strategic combination of capacity, flexibility and controllability of the power system is needed to handle these variations, along with storage and demand response.

**DEVICES FOR IMPROVING FLEXIBILITY AND CONTROL IN POWER BALANCING**

Given the reality that a major part of power production is now unpredictable, that both production and demand are dispersed, and that the magnitude and speed of variations for either is substantially increased, there is an urgent need for a wide area system approach and for the tools and controllable devices that are capable of balancing active power and reactive power. The world needs an integrated energy system in which each part interacts with all other parts in real time. This can be achieved by combining advances in power electronics with those in ICT for monitoring, protection and control.

In both AC and DC lines, power electronics using thyristors and transistors for high power applications offers more advanced options for flexibility and controllability such as FACTS and HVDC. Because reactive power cannot be transmitted across significant distances without excessive voltage or energy losses, managing its balance is more localized. Devices for reactive compensation and voltage control can be distributed throughout the power system, as in done in modern wind generators. Still, such devices need to be coordinated with larger FACTS devices for series compensation as well as SVC and STATCOM.

**A SYSTEM VIEW IS NEEDED**

Investments in smart power T&D infrastructure are essential to enable an efficient global clean energy society. The increased electrification and growing complexity of supply and demand requires a holistic system approach for power T&D development – with connected supply and demand – for the following three reasons:

- The electric power system is ONE interacting system in which supply and demand have to be continuously balanced at every moment to maintain voltage and frequency within strict limits. This requires increased knowledge and supervision of system behavior and wide area implementation of ICT for monitoring, protection, control, automation and visualization, together with increased flexibility from power electronics such as FACTS and HVDC.
- The increased share from variable RES of total installed power, which can change generation instantaneously, creates a paradigm shift for power system operation with basically unpredictable and rapidly fluctuating conditions requiring instantaneous system-wide compensation and balancing of frequency and voltage.
- With more small-scale solar, wind and hydro power as distributed generation and customer participation through demand response (sometimes in combination as “Prosumers”), the interaction among T&D systems will increase substantially.
A holistic system will require even more advanced, accurate and fast applications. Within a sound business management system (BMS), supervisory control and data acquisition (SCADA) will enable better, automated management of energy, assets, distribution and demand-side activities as well as substation automation. This complex interdependence raises one of the most critical issues: i.e. the urgent need for interoperability among different components and “systems of systems” from diverse vendors that need to “talk” to each other within the “digital power system”.

**Figure 6. The digital power system**

The level of interoperability needed in the digital power system will in turn require ongoing development and implementation of standards by dedicated organizations such as IEC, CENELEC and NIST. Such standards should allow the interchange of data while also ensuring cyber security. This will require cooperation among different stakeholders, planning and especially work-force empowerment through training and testing. Traditional skills in power engineering will need to be enhanced with new skills in ICT engineering. The implementation of new technology will drive the change and will affect the work force within the power T&D segment. Change management will be an essential part of the successful implementation of the digital power system in order to prepare the work force with necessary training.

**TO PREDICT THE FUTURE, YOU HAVE TO CREATE IT!**

There is near-consensus among energy sector players regarding the substantial challenges that lay at the interface of energy and the environment. Stakeholders also agree that most of the technologies needed to transform the energy sector are already available, and can be rapidly demonstrated and deployed. Unfortunately, the development of these technologies and actions seems to be progressing too slowly if considered in the diverse scenarios that highlight the consequences of both action and non-action (see e.g., IEA’s *Energy Technology Perspectives 2012*).

A smart and strong electrical infrastructure can make substantial contribution to meeting energy and climate goals, but decarbonisation of energy will require increased electrification. In the European Union, for example, different scenarios aim to increase the share of electricity from a current level of 20% to almost 40% by 2050.
There is, however, no single universal solution. Industry should avoid any contradiction of the “grid vs. ICT”; one cannot solve everything only by building more transmission lines or with new “apps” or smart meters. Both elements are vital to a strong and smart power T&D system and new power electronics can help both elements. FACTS, especially VSC-based devices for compensation at the transmission level, together with boosting the development of VSC technologies for HVDC, provides increased flexibility to support smoother RES integration, voltage regulation and reactive power control. In the future, distribution systems with more connected DER will be similar to transmission systems. A static synchronous compensator (STATCOM) is based on VSC technology with power transistors and provides dynamic voltage control in transmission and distribution systems. Distributed FACTS (D-FACTS) and devices for distribution, such as D-STATCOM, can provide similar flexibility for distribution applications. These are the smart and strong “apps” needed. The technology is available but has to be demonstrated and deployed.

History demonstrates the value of close cooperation between state-owned utilities (which were often vertically integrated to manage generation, transmission and distribution) and private companies (which have their own R&D resources and in-house power system expertise). New approaches are needed to stimulate early investments in infrastructure with a system view. Thus, it is important that policy makers, regulators and governments establish the framework to allow for and finance necessary R&D and long-term investments.
2 Introduction

2.1 ISGAN Power T&D Systems objectives

The main objective of ISGAN’s Annex 6 work within Power Transmission and Distribution Systems is to establish a long term vision for the development of Smarter and Stronger Power T&D electricity systems. Power transmission and distribution provides the infrastructure to integrate distributed and large-scale renewable energy and has to be recognized as such. This work consists of efforts to improve the understanding of Smart Grid technologies applicable to, or influencing, system performance, transmission capacities and operation practices as well as to accelerate their development and deployment. This includes promoting the adoption of related enabling regulatory and government policies. This work focuses on system related challenges for transmission and distribution systems. The initial work on Smarter and Stronger Power Transmission Systems is presented in this paper.

The ISGAN Annex 6 is organized into four main areas all influencing the Power T&D System as seen in figure 3 below and are covered in four tasks. This report is part of the work within task 3 (Technology Development and Demonstration) and task 4 (System Operation Management and Security) with a special focus on the introduction of power electronics (FACTS, HVDC) to enhance transmission capacity, stability and flexibility for power delivery as well as the ICT development in Power Utility Automation, Wide Area Monitoring and Network Management to enhance visibility and controllability.

FIG 7. ISGAN Annex 6 Power Transmission & Distribution Systems

It is, however, important to point out that all four aspects interact with no clear definition of cause and effect. However, policy and regulation reflecting the overall importance of reliable electric power supply, environmental aspects and public needs and acceptance should be the prime mover. In some cases, rapid technology development i.e. within ICT and power electronics, is both an enabler and driver for changes. Finally, it is important to remember that the Power T&D system is to supply all of us today with high quality and reliable electricity as “consumers” while tomorrow we may be more active “prosumers”, with PV cells on the roof or on the wall, driving an electric car and using demand response appliances.

The aim of this report is to identify the potential and feasibility of new technologies and to make recommendations on how to stimulate the demonstration and deployment of promising technology options, for example, through large scale demonstration projects. Necessary measures, practices and standards should be identified to allow faster, more efficient and more reliable deployment of new technology as well as to manage risks and interoperability. Available Smart Grid conceptual models, domains and structures from USA (FERC, NERC, NIST) and Europe (EEGI, CENELEC, ENSTO-E) as well as IEC and CIGRE have been used as a base for this work.
2.2 Conclusions of ENARD

ISGAN Annex 6 follows up on earlier work within IEA Implementing Agreement on Electricity Networks, Analysis, Research and Development (ENARD). The ENARD Annex IV on Transmission Systems worked out a long-term perspective and a vision for the development and evolution of transmission system planning and operation, motivated by the established targets for energy system developments and security of supply requirements. The Annex work concluded that urgent action is needed to make the power system able to safely and economically accommodate the dramatic changes it is required to undergo. A main message is that the "right" investment in transmission capacity, which must be stimulated, may be regarded as "overinvestment". Taking into account the very long planning and consent processes, and accounting for the technical aspects in the regulatory and market framework transmission system, investments may be "necessary" even though there is a chance that they may be underutilized during parts of their lifetime.

VISION for transmission system developments

- **Paradigm shift:**
  - Variable generation will be a main part of the base power
  - Fossil fuel (previously "conventional") generation becomes peaking units

- **Increasing need for power transmission and energy storage**
  - Generation further away from load centres and increasing variations in power flow
  - Increased value of interconnections and energy storage due to
    - Periods of generation surplus and risk of negative prices
    - Longer periods of low wind and lack of production capacity

- **Large capacity (multi-GW) connections will be more common**
  - These will challenge present security standards (n-1 and similar)

- **Flexibility becomes increasingly important**
  - Creates possibilities for "smart solutions" in distribution and transmission

- **Market evolution**
  - Market design must reflect and support the changes in the system
  - Intra-day and real-time markets will become increasingly important

Specific recommendations were put forward from the Annex concerning transmission expansion planning, market analysis and system operation:

Secure transmission operation requires more coordination and integration at TSO and TSO-DSO levels, as well as enhanced tools and new operational security rules. Flexibility and controllability become increasingly important.

The Smart Grid development may result in future distribution and sub-transmission networks that require different services from the transmission system than today. The increasing share of local generation and mix of loads results in stronger variability also at the distribution level. Flexibility and controllability are key properties to manage the variability of the future power system. Developments towards more active demand side participation could be particularly important to cope with variability at the lowest possible cost. This can be an important enabler of the Smart Grid vision.
The challenges related to balancing the variability of the future system must be better understood. To this aim, techniques and tools for power balancing assessments must be devised.

Probabilistic risk approaches for operation should be developed and tested. This is important as a supplement to the deterministic N-1 criterion which has mostly been used in the operational context. N-1 means that only one event, e.g. the loss of one transmission line, is considered. Implementation of new security criteria and operational standards relies more heavily on ICT, control systems and load flexibility. With the increasing dependence on the ICT solutions, cyber security also becomes an increasingly important issue.

Online analysis tools for very large systems should be developed. Phasor measurement units (PMUs) should be installed in all major sub-stations to stimulate development of Wide Area Monitoring Systems (WAMS). Finally, there is a need to develop new applications for on-line and off-line analysis based on the availability of phasor measurements, as well as closed loop control applications as Wide Area Monitoring And Control (WAMPAC).

3 Background and overview

3.1 A Framework for the Smart Grid

![Smart Grid Framework (NIST)](image)

FIG 8. Smart Grid Framework (NIST)

With the greater application of ICT to handle the increased and faster communication flow between a larger number of actors in the Power System, there is now a common understanding of the need for standardization and interoperability of the ICT products and “systems of systems”. This is handled globally within IEC as well as within CENELEC (EUROPE), NIST (USA) and other National or International organizations. NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 1.0 is structured in domain interconnected with electrical flows of energy as well as secure communication flows of information and commands. Version 2.0 was released in February 2012 and a Smart Grid Interoperability Panel (SGIP) has been created.
FIG 9. SGAM framework (CENELEC Reference Architecture)

FIG 10. Transmission Domain with main functions (NIST)
In December 2012, a set of comprehensive documents were published, provided by the CEN-CENELEC-ETSI Smart Grid Coordination Group (SG-CG), being responsible for coordinating the ESOs reply to M/490 (Mandate). This includes a Smart Grid Architecture Model (SGAM) which is an adaption of the NIST conceptual model for Europe extended with Distributed Energy Resources (DER) as well as a first set of proposed standards. In this report from ISGAN, the NIST definition on main transmission applications is used: Control, Protect, Measure, Record, Stabilize and Optimize. In addition to the above, NIST states:

*Actors in the Transmission domain typically perform the applications shown in the figure (FIG.10). The Transmission domain may contain Distributed Energy Resources, such as electrical storage or peaking generation units. Energy and supporting ancillary services (capacity that can be dispatched when needed) are procured through the Markets domain; scheduled and operated from the Operations domain; and finally delivered through the Transmission domain to the Distribution domain and ultimately to the Customer domain.*

What can be added is that Transmission today also may include Power electronics (FACTS and HVDC) which, besides allowing larger power transmission over long distances, can be used to Stabilize and Optimize the Power System. This is described later for the Nordic Power System and also in the context of Wide Area Monitoring Control and Protection (WAMPAC). The HVDC VSC technology is now being deployed for different onshore and offshore applications, including wind farms, and the concept of DC grid solutions is being discussed within the "North Seas Countries' Offshore Grid Initiative (NSCOGI)".

While HVDC classic solutions with thyristors have long experience from several manufacturers and users, the HVDC VSC with transistors has more limited experience from only one manufacturer (ABB). However, the latter is currently deployed by three major manufacturers (ABB, Alstom, Siemens) with slightly different technology and is being further developed in China. The possibility of a DC grid raises here the question of interoperability between different manufacturers and how to design reliable and selective protection systems as well as efficient control. CIGRE and CENELEC are now working on these issues and available information is used as reference for this report.

Offshore HVDC transmission for wind farms represents huge investments requiring very high reliability and availability. At the same time, the consequences of a failure could be severe. There is a need to verify equipment and systems and also manage the risk. Therefore, an ongoing Joint Industry Project by DNV KEMA & STRI, with major stakeholders for the North Sea and Baltic Sea wind farm deployment, is working on this in parallel with the ongoing work on recommendations and standards within CIGRE and CENELEC.

When connecting the offshore wind farms to land, either with HVAC or HVDC, the onshore transmission grid has to be strengthened. In addition, introduction of onshore wind and solar generation requires enhanced transmission to handle the variation. This is very well described for Europe in the latest ENTSO-E ten year plan (TYNDP 2012). Besides the construction of new lines, a greater use of FACTS and HVDC offers solutions to increase flexibility and power transmission capacity in the existing transmission grid. The use of existing corridors and the conversion of existing transmission lines from AC to DC are being studied in Europe and the U.S. By converting an existing AC line to DC, it is possible to significantly increase the power transfer and by using HVDC VSC technology also enhance the flexibility. Finally, the planned increase of Concentrated Solar Plants in "the sun belt" would often need HVDC transmission to deliver the power to consumption regions. This includes the EUMENA DERTEC vision of harvesting sun in Sahara to export to Europe, the Middle East and the rest of Africa. During the day, a small area of desert would suffice to produce all necessary energy.
3.2 The Nordic Electrifying Experience

The Nordic Power System, including Finland, Norway, Sweden and part of Denmark, is operated as one common AC frequency area connected with the rest of Europe via HVDC links. The four countries have a long history of close cooperation in the development and operation of the Nordic Power System. One reason is the significant differences in the primary energy sources for electricity generation as seen in the figure below. The complete Nordic system has 51% hydro, 3% wind, 20% nuclear and 25% other thermal but this mix varies significantly between the four countries.

While Norway uses almost 100% hydro power for generation, Sweden is a mix of hydro and nuclear with additional thermal units combined with district heating. Consequently, Sweden and Norway have a low carbon footprint electricity generation while Denmark and Finland are still more dependent on fossil fuel. Denmark, however, has one of the world’s most ambitious plans for wind power and also Sweden is investing in wind power. A complete picture on the primary energy balance of the four countries shown in the table below is from BP Statistical Review. Here we can see that although the carbon footprint is low for electricity generation, there is high oil consumption, mainly from transport. The electrification of the transport sector is therefore required to further reduce the carbon footprint.

Norway has already one of the highest per capita consumption of electricity in the world with 25 MWh/capita, while Sweden and Finland are on the same level as the U.S. and Canada with around 15 MWh. This is significantly higher than the world average of 3 MWh/capita and year. Denmark is on a typical European level with 6 MWh per capita and year. To reduce dependence on fossil fuel, Denmark is “electrifying” the energy system which increases electricity consumption by utilizing more wind power. This is demonstrated on the island of
Bornholm in the EcoGrid project. However, it is a long and large process to electrify the complete energy system. BPA statistical review states 1 ton of oil is equal to 12 MWh. This conversion factor is very simplified and differs in different processes. However if this is used for the Nordic energy system to replace all current oil consumption with electricity, we come up with some very high figures, as seen in the table.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Denmark</td>
<td>29</td>
<td>26</td>
<td>37</td>
<td>36</td>
<td>39</td>
<td>39</td>
<td>6</td>
<td>7</td>
<td>6</td>
<td>6</td>
<td>6</td>
<td>1,3</td>
<td>101</td>
<td></td>
</tr>
<tr>
<td>Finland</td>
<td>49</td>
<td>54</td>
<td>63</td>
<td>70</td>
<td>81</td>
<td>81</td>
<td>5</td>
<td>15</td>
<td>16</td>
<td>15</td>
<td>16</td>
<td>1,6</td>
<td>125</td>
<td></td>
</tr>
<tr>
<td>Norway</td>
<td>103</td>
<td>122</td>
<td>123</td>
<td>133</td>
<td>124</td>
<td>124</td>
<td>5</td>
<td>24</td>
<td>25</td>
<td>25</td>
<td>25</td>
<td>1,2</td>
<td>129</td>
<td></td>
</tr>
<tr>
<td>Sweden</td>
<td>137</td>
<td>147</td>
<td>148</td>
<td>153</td>
<td>156</td>
<td>156</td>
<td>10</td>
<td>16</td>
<td>15</td>
<td>14</td>
<td>15</td>
<td>1,1</td>
<td>183</td>
<td></td>
</tr>
<tr>
<td>TOTAL</td>
<td>319</td>
<td>348</td>
<td>371</td>
<td>401</td>
<td>411</td>
<td>411</td>
<td>26</td>
<td>16</td>
<td>16</td>
<td>16</td>
<td>16</td>
<td>1,3</td>
<td>538</td>
<td></td>
</tr>
</tbody>
</table>

According to this calculation, the Nordic power generation should almost double from 400 TWh to 400 + 538 = 938 TWh. Now electrical cars are more efficient compared to oil driven cars since the energy is lost as heat. But still, power generation must expand and with this, the power T&D grid. For the reasons above, the Nordic Power System provides a good mix of different energy sources with related challenges which is of interest for the development in other parts of the world. As noted, Norway and Sweden already have a high electrification level. The following more detailed review of the Nordic Power System development, especially technology applications and market design, can be used for global knowledge sharing, although each region and country are different and have local challenges.

At the turn of the 19th and 20th centuries, Sweden was one of the first countries to be electrified based on hydro power. As in many other countries, this was done in local clusters. This included the electrification of the 500 km railroad to connect the mines in Northern Sweden with the port of Narvik in Norway. The Swedish side was electrified 1915 and completed on the Norwegian side 1923. The electricity was supplied from the hydro power plant in Porjus which was constructed between 1910 and 1915. These electrical trains, driven by hydropower, were an early example that “clean energy” is possible.

Three-phase AC power transmission was developed in several countries and the voltage level was increased to allow for more transmission with lower losses. In Sweden, a 220 kV transmission was commissioned during the 1930s. One of the main challenges for Sweden was that the hydro power resources were concentrated in the northern part of the country while consumption was in the southern part. Since this was a distance of almost 1000 km, new technologies for power transmission were investigated and tested by the Swedish State Power Board (Vattenfall) and ASEA (Now ABB). These technologies included Extra High Voltage (400 kV) AC, series compensation, as well as HVDC.

The 950 km transmission line was put into service in 1952 as the first 400 kV installation in the world and series compensated in 1954 as the first in the world. The concept of series compensation had been implemented earlier on 220 kV in Sweden. HVDC was actually considered and tested also for the first north-south link, but the 400 kV HVAC series compensated technology was considered at the time a more reliable option. The first commercial HVDC link in the world was with a cable connecting the island ofGotland with the Swedish mainland (1954). The main reason was to supply the island with hydro power at the same price level as mainland Sweden. This was the start of many similar projects in the Nordic countries and around the world for what was later called “flexible alternating current transmission system” (FACTS) and HVDC for different applications.

Today, the Swedish 400 kV system consists of a number of series compensated 400 kV transmission lines between the hydro power in the north and consumption in the south. 19
This includes a thyristors controlled series capacitor as a state of the art FACTS function for one of the 400 kV lines. A few 220 kV transmission lines remain but regional grids of 130 kV are used as sub transmission to interface with distribution. The Norwegian transmission grid with 330 kV and 400 kV covers long distances with few transmission lines. It is supported by a number of Static VAR Compensators (SVC), another important FACTS application to stabilize the voltage and allow increased power transfer. The 330 kV system is now being uprated to 400 kV.

The Nordic electric power cooperation began already in 1915 with two sub-sea 25 kV AC cables to deliver Swedish hydropower to Denmark. As already mentioned, the Swedish hydropower plant Porjus supplied the railroad between Sweden and Norway with an 80 kV single phase transmission line. However, it was not until 1959-60 that the Nordic power system was interconnected at 220 kV from Norway to Sweden and from Sweden to Finland. All three countries were mainly self sufficient on hydropower and additional sources which means there were no real reasons for an integrated system until a climate “disturbance” climate created this reason, in the 1950s!

Hydropower has the advantage that it can store energy and be a “spinning reserve” to balance the power system with needed. Swedish hydropower comes from long rivers with several dams and plants which have to be operated in coordination with each other. This means they can be turned on and off to balance the system, but within certain limits. Therefore, Swedish hydropower is not suitable for long term storage of water. Norwegian hydropower is different, with larger storage facilities and high altitude generation. When Sweden experienced very dry summers, Norway had normal rain and could supply Sweden for longer periods with hydropower. Consequently, a special agreement was established to “store” Swedish hydropower in Norwegian dams. Occasionally the opposite conditions were applied, when Sweden had to supply Norway (and Finland) with hydropower. All countries, therefore, realized the advantages to cooperate in a larger “pool” and power system. In 1963, NORDEL was created as the organization for this cooperation.

The 1954 HVDC connection to the island of Gotland was the first HVDC link in the world. In 1965, the Nordic System was connected with mainland Europe via the HVDC link Konti-Scan between Sweden and Denmark. These HVDC projects used mercury valves. The thyristors technology was implemented by ABB for electric traction in locomotives for the Swedish railroads. Thyristors were now also introduced in 1970 for HVDC in an upgrade for the Gotland connection. 1976 saw the Skagerrak HVDC sub-sea link connecting Norway via Denmark to continental Europe.

The Nordic Transmission System Operators (TSOs) have a long history of cooperation in grid development in the context of NORDEL, the previous cooperative organization for the Nordic TSOs. The Nordic power systems (with the exception of Iceland) are strongly connected and interdependent on each other, and hence close cooperation is essential to ensure a rational development of the system. After the UK, the Nordic electricity market with Finland, Norway and Sweden were the first to deregulate in Europe and allow "Third Party Access". Furthermore, it became the first multi national electricity market. This process started in Norway 1991 and Sweden in 1992 with the creation of the Norwegian and Swedish TSOs.

In 1996, a joint Norwegian-Swedish power exchange was established. The exchange was named Nord Pool ASA. Finland joined Nord Pool ASA in 1998. The Nordic market became fully integrated as Denmark joined the exchange in 2000. Nord Pool Spot was established as a company in 2002 as the world’s first market for trading power. Today it is also the world’s largest market of its kind, and is the leading market for buying and selling power in the Nordic region. One consequence of the electricity market realignment is the increased need
for data exchange between the actors in it. A practical prerequisite for meeting this need is some form of electronic data exchange, EDI (Electronic Data Interchange). For this reason a common EDI system called Ediel was developed. The Nordic Ediel Group was founded after Ediel Nordic Forum was reestablished as a pan European body under the name of ebIX (see www.ebix.org). As the Nordic market integrates with Europe, there is a need for a common standard. A Role Model has been developed by ENTSO-E, identifying roles and domains for an information interchange in the electricity market. The four Nordic TSOs and Nord Pool Spot have set up a project for migration of the message exchanges towards one common message standard.

FIG 12. The Nordic Electric Energy Exchange (Svenska Kraftnät)

A European “supergrid” is often mentioned and proposed as the future solution. This can be defined as a pan-European transmission network facilitating the integration of large-scale renewable energy and the balancing and transportation of electricity, with the aim of improving and integrating the European electricity market. In this context, the Nordic power grid can serve as an example where the original aims were similar. An overall motivation for transmission interconnections in the Nordic countries was to optimize utilization of the renewable hydro generation systems with their different characteristics concerning storage capacity and changing inflow patterns. Very early on, this required close coordination in operation and planning, which made it easier to develop a common electricity market after deregulation as described above. More recently, this collaboration has made it possible to develop and operate common intraday and balancing markets, which is expected to become
increasingly important in the future. Another important feature of the Nordic system is the large number of HVDC links. These provide flexibility in operation and a significant transmission capacity towards the neighboring synchronous interconnections (Russia, Baltic countries and Central Europe).

The Nordic co-operation on grid development is now taking place within the wider regional context provided by the regional groups North Sea and Baltic Sea of ENTSO-E, and the European organization for TSOs, in addition to bilateral co-operation when required. Three common Nordic grid master plans have been developed in the last ten years in the context of NORDEL, the previous cooperative organization for the Nordic TSOs which now is part of ENSTO-E. Joint Nordic grid development is essential to support further development of an integrated Nordic electricity market, as well as increased capacity to other countries and integration of renewable energy sources (RES). The main investment drivers for system development in the Nordic countries are:

1. Connection of new renewable and conventional generation units
2. Increased market integration inside the Nordic system as well as on its borders
3. Preservation of security of supply as power transfers increase

The further integration of the Nordic countries and connections between Nordic and Continental European countries make the system more robust and accommodate the integration of large amount of wind power and other renewable energy sources within and around the Nordic countries, as well as provide balancing and storage for Continental Europe. This is described in the ENSTO-E Ten Year Network Development Plan (TYNDP).

FIG 13. Planned new Nordic HVDC connections (ENSTO-E)

Market integration is the main driver for most of the projects, but as for the mid-term projects, renewable integration is also made easier in the whole system with increased capacity.
between the Nordic, Baltic and continental systems. Some projects are related to the security of supply (Arctic region) and some directly with RES integration. There are also some projects related to integration of large conventional generation (nuclear units planned in Finland). Some transmission capacity will be added gradually from the mid-term, since additional internal reinforcements will be finished within the long-term timeframe. Large investments in RES generation are expected towards 2020 throughout the Nordic region. Reinforcements in the internal grids as well as increased interconnector capacity are needed. Increased surplus and more interconnectors will lead to a stronger north-south flow, and domestic reinforcements are especially needed in this direction.

For the long-term time horizon, additional grid extension inside Germany is required to meet the foreseen generation (especially wind) in northern Germany, the increasing geographical imbalance between generation and consumption, as well as the long distances separating generation and consumption regions. German TSOs are considering several DC-connections, allowing the north-south and northeast-southwest power flow and enhancing grid stability. This affects the future flows to and from the Nordic Area. Similarly, future connections between the Baltic system and continental Europe (LitPol link) affects the transmission needs also in the Nordic system and between Nordic and Baltic systems.

The South-West link is an embedded HVDC. The Swedish North-South VSC HVDC-link is duplicated and originally an additional link to Norway was planned. An HVDC cable from Norway to Germany is planned to be commissioned by 2018, and a cable between Norway and the UK is planned to be commissioned by 2020. The expected capacity for these links is 1400 MW. Kriegers Flak Combined Grid Solution (CGS) from eastern Denmark to Germany is considered to be a pilot project to build, utilize and demonstrate a multi-vendor, multi-terminal HVDC VSC offshore system to interconnect different countries and integrate offshore wind power. This will be a full-scale prototype of future European HVDC super grids, e.g. offshore transmission systems in the North Sea and Baltic Sea. Kriegers Flak CGS is a project of pan-European significance and has been awarded a grant from the EEPR.

The project of a new (third) interconnection between Polish and German systems (Ger-Pol Power Bridge) is interesting for the Nordic area in the way that it allows connection of a possible future off-shore super-grid to the rest of the network of central Europe and transit RES (wind off- and onshore) to consumption centers in central Europe. After commissioning the project, it is possible to build a second DC link to Sweden and transit renewable energy from Scandinavian power systems to consumption centers in continental Europe.

The development of an offshore grid in the North Sea has been identified as one of the priorities in the European Commission’s October 2011 Energy Infrastructure Package. Although the backbone of such an offshore grid is likely to commence in the next ten years, it is only beyond 2020 and 2030 that the benefits of an integrated offshore grid are expected to be most significant. In December 2010, the ten governments of the North Sea countries (Ireland, UK, France, Belgium, Luxembourg, Netherlands, Germany, Denmark, Sweden and Norway) signed a Memorandum of Understanding to provide a coordinated, strategic development path for a possible offshore transmission network in the North Sea. The ENTSO-E work in this domain is now being taken forward within the North Sea Countries’ Offshore Grid Initiative (NSCOGI). It should be recognized that in addition to the physical challenges of planning, constructing and operating such an interconnected European system, there are many regulatory, legal, commercial and political hurdles that must be identified and addressed. NSCOGI will look at these wider issues as part of its deliverables.
### 3.3 A Global View

<table>
<thead>
<tr>
<th>Million toe</th>
<th>Oil</th>
<th>Natural gas</th>
<th>Coal</th>
<th>Nuclear energy</th>
<th>Hydro electricity</th>
<th>Renewables</th>
<th>Total</th>
<th>Percent Fossil</th>
<th>Percent RES/Hyd</th>
<th>Percent RES</th>
<th>CO2 Mton</th>
<th>CO2 per capita</th>
</tr>
</thead>
<tbody>
<tr>
<td>US</td>
<td>850</td>
<td>611</td>
<td>526</td>
<td>192</td>
<td>59</td>
<td>39</td>
<td>2278</td>
<td>87%</td>
<td>4%</td>
<td>2%</td>
<td>6127</td>
<td>19.4</td>
</tr>
<tr>
<td>Canada</td>
<td>103</td>
<td>86</td>
<td>24</td>
<td>20</td>
<td>79</td>
<td>4</td>
<td>316</td>
<td>67%</td>
<td>26%</td>
<td>1%</td>
<td>611</td>
<td>17.5</td>
</tr>
<tr>
<td>Brazil</td>
<td>118</td>
<td>24</td>
<td>14</td>
<td>3</td>
<td>91</td>
<td>7</td>
<td>256</td>
<td>61%</td>
<td>38%</td>
<td>3%</td>
<td>474</td>
<td>2.4</td>
</tr>
<tr>
<td>Austria</td>
<td>13</td>
<td>9</td>
<td>3</td>
<td>-</td>
<td>8</td>
<td>2</td>
<td>34</td>
<td>73%</td>
<td>27%</td>
<td>4%</td>
<td>71</td>
<td>8.4</td>
</tr>
<tr>
<td>Belgium</td>
<td>33</td>
<td>17</td>
<td>3</td>
<td>11</td>
<td>0</td>
<td>2</td>
<td>66</td>
<td>81%</td>
<td>3%</td>
<td>2%</td>
<td>156</td>
<td>14.2</td>
</tr>
<tr>
<td>Denmark</td>
<td>8</td>
<td>4</td>
<td>4</td>
<td>-</td>
<td>3</td>
<td>20</td>
<td>85%</td>
<td>14%</td>
<td>14%</td>
<td>51</td>
<td>9.1</td>
<td></td>
</tr>
<tr>
<td>Finland</td>
<td>10</td>
<td>4</td>
<td>5</td>
<td>3</td>
<td>3</td>
<td>29</td>
<td>63%</td>
<td>19%</td>
<td>9%</td>
<td>57</td>
<td>10.6</td>
<td></td>
</tr>
<tr>
<td>France</td>
<td>84</td>
<td>42</td>
<td>11</td>
<td>97</td>
<td>14</td>
<td>3</td>
<td>252</td>
<td>55%</td>
<td>7%</td>
<td>1%</td>
<td>400</td>
<td>6.1</td>
</tr>
<tr>
<td>Germany</td>
<td>115</td>
<td>75</td>
<td>77</td>
<td>32</td>
<td>5</td>
<td>19</td>
<td>322</td>
<td>83%</td>
<td>7%</td>
<td>6%</td>
<td>834</td>
<td>10.2</td>
</tr>
<tr>
<td>Italy</td>
<td>73</td>
<td>68</td>
<td>14</td>
<td>-</td>
<td>11</td>
<td>6</td>
<td>173</td>
<td>90%</td>
<td>10%</td>
<td>3%</td>
<td>441</td>
<td>7.2</td>
</tr>
<tr>
<td>Norway</td>
<td>11</td>
<td>4</td>
<td>1</td>
<td>12</td>
<td>3</td>
<td>42</td>
<td>36%</td>
<td>64%</td>
<td>1%</td>
<td>44</td>
<td>8.6</td>
<td></td>
</tr>
<tr>
<td>Russia</td>
<td>129</td>
<td>373</td>
<td>90</td>
<td>39</td>
<td>38</td>
<td>0</td>
<td>669</td>
<td>89%</td>
<td>6%</td>
<td>0%</td>
<td>1629</td>
<td>11.4</td>
</tr>
<tr>
<td>Sweden</td>
<td>15</td>
<td>1</td>
<td>2</td>
<td>13</td>
<td>15</td>
<td>4</td>
<td>51</td>
<td>37%</td>
<td>37%</td>
<td>7%</td>
<td>59</td>
<td>6.2</td>
</tr>
<tr>
<td>China</td>
<td>438</td>
<td>97</td>
<td>1676</td>
<td>17</td>
<td>163</td>
<td>12</td>
<td>2403</td>
<td>92%</td>
<td>7%</td>
<td>0%</td>
<td>8210</td>
<td>6.1</td>
</tr>
<tr>
<td>India</td>
<td>156</td>
<td>56</td>
<td>271</td>
<td>5</td>
<td>25</td>
<td>8</td>
<td>521</td>
<td>93%</td>
<td>6%</td>
<td>1%</td>
<td>1683</td>
<td>1.4</td>
</tr>
<tr>
<td>South Africa</td>
<td>26</td>
<td>4</td>
<td>91</td>
<td>3</td>
<td>3</td>
<td>0</td>
<td>124</td>
<td>97%</td>
<td>0%</td>
<td>0%</td>
<td>450</td>
<td>8.7</td>
</tr>
<tr>
<td>South Korea</td>
<td>106</td>
<td>39</td>
<td>76</td>
<td>34</td>
<td>1</td>
<td>1</td>
<td>256</td>
<td>86%</td>
<td>1%</td>
<td>0%</td>
<td>717</td>
<td>14.3</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>4032</td>
<td>2843</td>
<td>3532</td>
<td>626</td>
<td>779</td>
<td>166</td>
<td>11978</td>
<td>87%</td>
<td>8%</td>
<td>1%</td>
<td>33041</td>
<td>4.7</td>
</tr>
</tbody>
</table>

BP has published BP Statistical Review annually which illustrates the production and consumption of different types of energy that are all measured as Mtoe, Million tonnes oil equivalents. Different conversion factors are used for different energy. These conversion factors may differ between BP and other studies, especially for electricity generation. BP states: “The primary energy values of nuclear and hydroelectric generation, as well as electricity from renewable sources, have been derived by calculating the equivalent amount of fossil fuel required to generate the same volume of electricity in a thermal power station, assuming a conversion efficiency of 38% (the average for OECD thermal power generation).”

![Image of energy consumption table]

The above table showing world primary energy demand is from WEO2012 (IEA). The 2010 figures differ from BP mainly due to the difference in conversion factors and that IEA also include traditional and new bio energy use. However, the conclusion is similar. At around 1%,
renewable energy represents a very small part of the present primary energy use. Hydropower represents 7% in the BP statistic and 2.3% in the IEA statistic due to the different conversion factors. (For IEA 1 Mtoe = 11 630 GWh and for BP 4 400 GWh.) IEA presented at WEO 2012 three different future scenarios. The current policies scenario means that we continue as per adopted policies mid 2012. The new policies scenario means that in addition new recently announced measures are implemented. The 450 scenario means to limit CO2 concentrations to 450 ppm with a 50% chance to limit global warming to 2 °C. Scenario corresponds to a long-term average global temperature increase of 3.6 °C. Therefore, the policies adopted determine how much clean energy and energy savings are required and, by this, how the power system should be designed. If we selected an urgent path to limit emissions and global warming this would result in urgent investments in smart and strong power systems to integrate a large deployment of RES.

The above table is from IEA WEO 2012 and shows electricity generation in TWh. In the 450 scenario, the hydro and other renewables increase from below 20% to almost 50% of generated energy. Hydro generation doubles while other renewables increase 12 times in electricity generation. If we do not successfully implement the 450 scenario, the most probable alternative may be the new policies scenario. This still requires an increase of 7 times compared to 2012 and almost a doubling of hydropower.

This represents a big challenge that requires different measures on policies and technology. While the Nordic electricity system includes in a large part renewables, mainly hydro, global energy is more dependent on fossil fuels. It is not possible to treat all regions and countries as one. Even within Europe there are big variations between regions and countries. The above statistic for 2010 from BP Statistical Review illustrates these differences. The U.S. and Canada have the highest consumption of fossil fuels and emission of CO2 per capita of the selected countries while China now has the highest total volume for coal and CO2 emissions. Globally we have an enormous challenge to replace fossil fuel with clean energy. This challenge will vary in different countries as seen in the table below:
The Nordic countries together with the U.S. and Canada already have a high electrification measured as MWh per capita. Despite rapid growth, Brazil, India and China have a very low electrification measured as MWh/capita. In fact, the Nordic and North American electricity consumption is between 10-20 times higher than the large populations of Asia and South America. The integration for more power generation is a priority for the emerging markets including the BRICS countries (Brazil, Russia, India, China, South Africa). This is why the development and deployment of Power Electronics and “Super Grid” applications is accelerating in India and especially in China. Today these countries are highly dependent on coal for electricity generation. In countries with high oil consumption for transport, the challenge is to electrify this when possible. If all oil in 2010 is replaced by electricity according to the BP conversion factor, the world electricity production should increase from around 20 000 GWh with an additional 50 000 GWh. But as seen, there are still big differences between countries. To replace fossil energy with electricity from clean energy and provide electricity to those who do not have it is what some call “the third industrial revolution”.

---

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>US</td>
<td>2703</td>
<td>3185</td>
<td>3517</td>
<td>3990</td>
<td>4257</td>
<td>4331</td>
<td>316</td>
<td>14</td>
<td>14</td>
<td>13</td>
<td>13</td>
<td>1.6</td>
<td>10199</td>
</tr>
<tr>
<td>Canada</td>
<td>460</td>
<td>478</td>
<td>551</td>
<td>599</td>
<td>614</td>
<td>582</td>
<td>35</td>
<td>17</td>
<td>16</td>
<td>15</td>
<td>15</td>
<td>1.6</td>
<td>12322</td>
</tr>
<tr>
<td>Brazil</td>
<td>194</td>
<td>223</td>
<td>276</td>
<td>349</td>
<td>403</td>
<td>485</td>
<td>194</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>1.6</td>
<td>14171</td>
</tr>
<tr>
<td>Austria</td>
<td>45</td>
<td>50</td>
<td>57</td>
<td>61</td>
<td>61</td>
<td>71</td>
<td>8.5</td>
<td>8</td>
<td>8</td>
<td>8</td>
<td>8</td>
<td>1.6</td>
<td>155</td>
</tr>
<tr>
<td>Belgium</td>
<td>57</td>
<td>71</td>
<td>74</td>
<td>84</td>
<td>87</td>
<td>93</td>
<td>11</td>
<td>8</td>
<td>8</td>
<td>10</td>
<td>11</td>
<td>1.6</td>
<td>402</td>
</tr>
<tr>
<td>Denmark</td>
<td>29</td>
<td>26</td>
<td>37</td>
<td>36</td>
<td>36</td>
<td>39</td>
<td>6</td>
<td>7</td>
<td>6</td>
<td>6</td>
<td>6</td>
<td>1.3</td>
<td>101</td>
</tr>
<tr>
<td>Finland</td>
<td>49</td>
<td>54</td>
<td>63</td>
<td>70</td>
<td>70</td>
<td>81</td>
<td>5</td>
<td>15</td>
<td>16</td>
<td>15</td>
<td>16</td>
<td>1.6</td>
<td>125</td>
</tr>
<tr>
<td>France</td>
<td>344</td>
<td>420</td>
<td>494</td>
<td>541</td>
<td>576</td>
<td>573</td>
<td>66</td>
<td>9</td>
<td>8</td>
<td>7</td>
<td>8</td>
<td>1.7</td>
<td>1013</td>
</tr>
<tr>
<td>Germany</td>
<td>523</td>
<td>550</td>
<td>535</td>
<td>564</td>
<td>620</td>
<td>628</td>
<td>82</td>
<td>8</td>
<td>8</td>
<td>7</td>
<td>7</td>
<td>1.2</td>
<td>1388</td>
</tr>
<tr>
<td>Italy</td>
<td>186</td>
<td>217</td>
<td>241</td>
<td>277</td>
<td>304</td>
<td>313</td>
<td>61</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>1.6</td>
<td>677</td>
</tr>
<tr>
<td>Norway</td>
<td>105</td>
<td>123</td>
<td>129</td>
<td>143</td>
<td>136</td>
<td>124</td>
<td>5</td>
<td>24</td>
<td>23</td>
<td>25</td>
<td>29</td>
<td>1.2</td>
<td>128</td>
</tr>
<tr>
<td>Russia</td>
<td>962</td>
<td>1082</td>
<td>862</td>
<td>879</td>
<td>964</td>
<td>1036</td>
<td>143</td>
<td>7</td>
<td>6</td>
<td>6</td>
<td>6</td>
<td>1.1</td>
<td>125</td>
</tr>
<tr>
<td>Sweden</td>
<td>137</td>
<td>147</td>
<td>148</td>
<td>153</td>
<td>167</td>
<td>156</td>
<td>10</td>
<td>16</td>
<td>16</td>
<td>15</td>
<td>15</td>
<td>1.1</td>
<td>182</td>
</tr>
<tr>
<td>China</td>
<td>757</td>
<td>621</td>
<td>1007</td>
<td>1356</td>
<td>2500</td>
<td>4208</td>
<td>1354</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>10.2</td>
<td>5253</td>
</tr>
<tr>
<td>India</td>
<td>180</td>
<td>284</td>
<td>410</td>
<td>555</td>
<td>690</td>
<td>922</td>
<td>1210</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>5.1</td>
<td>1874</td>
</tr>
<tr>
<td>South Africa</td>
<td>143</td>
<td>165</td>
<td>188</td>
<td>244</td>
<td>245</td>
<td>260</td>
<td>52</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>1.8</td>
<td>314</td>
</tr>
<tr>
<td>South Korea</td>
<td>63</td>
<td>118</td>
<td>204</td>
<td>290</td>
<td>389</td>
<td>496</td>
<td>50</td>
<td>10</td>
<td>9</td>
<td>9</td>
<td>9</td>
<td>7.9</td>
<td>1277</td>
</tr>
<tr>
<td>World</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>520</td>
<td>48383</td>
<td>10</td>
<td></td>
<td>10</td>
<td></td>
</tr>
</tbody>
</table>

* Other includes geothermal, concentrating solar power and marine.

FIG 14. Power Capacity (GW) and Energy (TWh) addition 2010 – 2035 (IEA)
The above figure for WEO 2012 illustrates the additional generation needed for the new policy scenario. Oil is no longer used for power production but oil consumption for other purposes are maintained in all three scenarios. Our earlier calculation of replacing all oil with electricity from renewables was only hypothetical since oil will still be needed where it cannot be replaced. The introduction of electrical vehicles also needs less energy as electricity compared to the energy content of the oil used today. Furthermore, we need to differentiate between power and energy which is done in the figure above. Power is measured as Watt (W), kilo Watt (kW) or Mega Watt (MW). Electric energy is power multiplied with time and measured as Watt hours (Wh), kilo Watt hours (kWh) and Mega Watt hours (MWh). Our electricity bills show our consumption as kWh.

However, wind and sun is not constant and therefore wind power and solar power have a lower capacity factor, typically 20-30% compared to coal and nuclear plants with 80-90% and even higher. Therefore it is necessary to install more RES power in MW to get the same energy in MWh compared to fossil fuel and nuclear power plants. According to the IEA study, we need to deploy more than 1500 GW of solar and wind generating power to reach around 3000 TWh per year. Since one year has 8760 hours, this means around a 23% capacity factor. This increased installation of solar and wind generation results in larger variations between maximum and minimum values. To de-carbonize the power system requires therefore an increase of installed power even if energy consumption is constant or even reduced. In addition, we need more storage facilities. This is one reason why hydropower in the above figure operates at a lower capacity factor since it is used as storage to balance variable load and generation. The Power T&D infrastructure needs the capacity and flexibility to handle these larger and variable flows of power and energy.

As seen in the figure above on the deployment of renewables in the New Policies Scenario, their share of total world power generation expands substantially, from 20% in 2010 to 31% in 2035. It varies in different regions but a slight reduction in hydropower percentage remains the major source. This means the percentage in installed power is even higher than in the previous figures. Europe will have the largest challenge with an increased part of variable wind and PV. What is remarkable in this latest IEA study is that Concentrating Solar Power is so low. With the development of HVDC technology, the possibility to harvest large solar energy resources in desert areas and bring these to areas of large consumption (such as the EUMENA DESERTEC project) allows an even greater pace of deployment of renewables in many regions.
As part of the EU 20/20/20 goal, the installation of wind power is rapidly increasing in Europe which is illustrated in the figure above for 2035. This includes both onshore and offshore wind parks. Some of these offshore wind parks are relatively close to the shore and therefore conventional AC collection grids are directly connected to the main land AC grid at a suitable voltage level. Others require an HVDC for longer cable connections. All of them, however, require a smart and strong onshore transmission system.

It is a well known fact that the integration of variable RES, such as wind and solar power generation as distributed generation, as well as for the onshore and offshore wind farms, imposes new challenges for the power system operation. This is covered extensively in the literature and different studies such as IEA, EWIS and EWEA studies as well as the EU-DEEP project between 2004-2009 “Integrating Distributed Energy Resources into today’s electrical system”. The question is how much and with what is RES affecting the power system and what has to be done to mitigate these influences and ensure a high quality and reliable power delivery. “Integration of Distributed Generation in the Power System”, by Bollen and Hassan, describes the concept of “hosting capacity”.

This method can determine how much new Renewables/DER (Distributed Energy Resources) can be connected to a network without compromising the performance of the network. The approach starts with defining a performance index and calculating its value as a function of the DER penetration level. When the value of the performance index drops below the acceptable limit, the hosting capacity is reached. Next additional investment can increase the hosting capacity. This may be investment in the system but also investment in the DER units. The former may be in new lines, uprating of lines and FACTS. The latter may be in the form of more strict connection requirements as specified in the grid code.

The performance of wind power is different depending on the design of the turbine-generator sets. In the early installations during the 80s and 90s, fixed speed generators were used. Today the installed base is mainly variable speed generators, Double Infeed Induction Generator (DFIG) and Full Power Convertors (FPC). The performance of the wind turbine-generator is specified in available grid codes. If the wind park is connected via an HVDC link, the interaction with the onshore grid is different compared to the interaction within the offshore wind cluster. This is discussed in CIGRE report 370 from 2009 WG B4.39 “Integration of large Scale Wind Generation using HVDC and Power Electronics.”
4 Status of Feasible Transmission System Technologies & Solutions

4.1 HVAC and HVDC Power electronics

The development of Power Electronics, including FACTS and HVDC, has introduced new methods for new applications to create the Strong and Smart Power System. The figure below gives a summary of available technologies which are later described in detail.

![Diagram of Power Electronic Options (ABB)]

**FIG 17. Power Electronic Options (ABB)**

**A MATTER OF FACTS**

Power equals voltage multiplied with current. By increasing the voltage or the current we can increase the power. It is, however, more efficient to increase the voltage and that is why the power system steps up the voltage from generation to transmission over longer distances and then steps down for distribution using transformers. This is a well known “truth” that has been used for the last 100+ years. But when a system voltage is selected, it is fixed. This means that the voltage level within a power system has to be kept within specified levels for all parts of the power system. One way is by voltage regulation of the transformers interconnecting different systems. For longer transmission distances this is not sufficient. The inductive reactance of a transmission line consumes reactive power and causes a voltage drop. A rotating generator driven by a turbine delivers both active and reactive power to the network and controls both frequency and voltage. In addition, similar rotating machines, called synchronous condensers, are used to deliver (or consume) reactive power to regulate the voltage. But this is insufficient. Series and shunt compensation (FACTS solutions) on longer transmission lines is needed to control the voltage.

Series compensation in transmission, by installing capacitor banks in series with the line inductive reactance, was first introduced by ASEA/ABB in Sweden in 1948/1950 and simultaneously delivered for BPA in the U.S. at 220 kV. In 1954 the world’s first series 400 kV compensated transmission line was put in operation in Sweden. This allowed power transmission over a distance of almost 1000 km. The series capacitor was introduced to reduce the reactance of the line by compensating the inductive reactance X with a negative capacitive reactance XC and maintain a high voltage U at the end. With reference to the parameters in the figure below, the approximate transfer equation for electrical power P of a long transmission line may be written

\[ P_e = \frac{EU \sin \delta}{X - XC} \]
As can be seen from the definitions and formula above, the transferred power depends on the magnitude of the voltages, the reactance of the line, and the angle between the sending and the receiving end. This can simply be seen as a synchronous generator driving a synchronous motor at a constant speed corresponding to 50 or 60 Hz frequency. However, the reactance of transmission line in between imposes an angle between the generator and the motor. As long as this angle is small, the system is synchronized. But if it becomes too big, the sending and receiving ends lose synchronization and start rotating at different frequencies. A large angular difference will cause a system break down and a major disturbance. Series compensation allows more power transfer at a smaller angle and therefore improves the stability of the system.

Electrically, Sweden has a smaller use of capacitors. Today, all major Swedish 400 kV Transmission Lines from north to south, as well as the double circuit line interconnecting Sweden and Finland, are series compensated to increase the power transfer capability by:

— Increased dynamic stability of power transmission systems
— Improved voltage regulation and reactive power balance
— Improved load sharing between parallel lines

For one of the lines, Thyristor Controlled Series Compensation (TCSC) has been installed. The main reason is to limit the possibilities for Sub Synchronous Resonance (SSR) which
can damage connected large scale generator-turbine generators. The Forsmark nuclear power plant, situated in mid-Sweden, is interconnected with the north of the country by means of a number of 400 kV lines of varying lengths, all series compensated. However, one of the generator units at Forsmark, rated at 1300 MW, is subject to SSR risk in conjunction with certain conditions in the power grid. With the TCSC in operation, the SSR risk is eliminated for all possible system operating conditions. The benefits are increased availability of power from Forsmark and, thanks to series compensation, a high level of preserved power transmission over the system.

After the first installations for The Swedish State Power Board and BPA in the U.S., a large number of installations followed in Sweden and the western U.S. during the 1960s. The world’s first 800 kV series compensation was installed for FURNAS in Brazil in 1987-89. Today, Series compensation is installed in various voltage levels throughout the world, mainly to connect hydropower, but also for integration of renewables, as for example in Texas in the USA. With series capacitors, the capability of already existing power lines can be increased considerably, thereby decreasing the need for new lines in cases where the need for power transmission capacity has grown. Likewise, in green-field projects, the amount of transmission lines to take care of a certain amount of power transmission can be kept to a minimum. In summary, series compensation of power transmission circuits enables several useful benefits as follows:

- An increase of active power transmission without violating angular or voltage stability;
- An increase of angular and voltage stability without derating power transmission capacity;
- A decrease of transmission losses in many cases;
- A reduction in the number of required EHV transmission lines

The Power System consists of many voltage levels. Generation is at lower levels of a few kilo volts, e.g. 10 kV, and then stepped up to sub transmission and transmission levels of several hundred kilovolts, e.g. 400 kV or 500 kV. For distribution, the voltage level is reduced in steps, e.g. from 130 kV down to 10 kV, and finally to our 110 or 220 volt outlets. All these levels have to be controlled and kept within specified levels. This has always been required and handled with voltage control for generators and tap changer control for transformers. Shunt capacitors and shunt reactors have long been used to compensate the reactive power and control the voltage in the Power T&D system. A Rotating Synchronous Compensator is a synchronous machine that is powered from the grid. It has no physical load, delivers reactive power back to the grid, and controls voltage. What has changed is voltage regulation now has to be smarter and more flexible to handle the integration of variable and distributed generation and fluctuating power flows due to this, as well as the effects of deregulation of new commercial power flow demand. This is why FACTS devices and systems are needed even more to control the voltage and reactive power. In addition, so called “Phase shifting transformers” or so called “back-to-back HVDC” can be used as an interface between two subsystems.

Flexible AC Transmission Systems (FACTS) covers all of the power electronics based systems used in AC power transmission. Besides fixed and thyristor-controlled series capacitor (SC, TCSC), Static VAR compensators (SVC) are commonly used in transmission and distribution systems to control the voltage in steps with thyristor control. With the development of transistors for power applications (IGBT) this is used in what is called Synchronous static compensator (STATCOM). SVC, STATCOM and the older rotating synchronous compensator all provide reactive power compensation.

Similarly, the Swedish power system was the initial test bed for series compensation; the world’s first SVC with TSC technology was installed here 1972. This was further developed for combined TSC and TCR to CFE and Mexico and AEP in the U.S. between 1977-79. The
world's first SVC for 500 kV was installed in 1980 in China and for 735 kV in Canada in 1983.

The benefits of SVC to power transmission are:
— Stabilized voltages in weak systems
— Reduced transmission losses
— Increased transmission capacity to reduce, defer, or eliminate the need for new lines
— Higher transient stability limit
— Increased damping of minor disturbances
— Greater voltage control and stability
— Power oscillation damping

Systems interconnected via a relatively weak link often experience power oscillation problems. Transmission capability is then determined by damping. By increasing the damping factor (typically by 1-2 MW per MVAR installed) an SVC can eliminate or postpone the need to install new lines.

FIG 20. Example of SVC (ABB)

Over the years, SVCs of many different designs have been built. Nevertheless, the majority of them have similar controllable elements. The most common ones are:

- Thyristor-controlled reactor (TCR)
- Thyristor-switched capacitor (TSC)
- Thyristor-switched reactor (TSR)
- Mechanically switched capacitor (MSC)

The Norwegian transmission system is based on 300 kV and 400 kV. In the Norwegian power grid, the distances are long between generation and consumption. Many heavy industries, such as melting plants, are situated along the coast and they utilize energy-consuming production processes. In addition, Norway has several HVDC links to continental Europe originating along the coast. The grid had to be strengthened to meet the need for improved transmission capacity. This led to the initiation of the Mid-Norway project, with nine shunt capacitor banks to be installed in six different stations during 2007. Each bank is for 100 Mvar at 300 kV and is upgradable to 420 kV, since Statnett is now working on uprating some of their transmission lines from 300 kV to 400 kV using the existing lines. This exemplifies the possibility to increase the capacity and flexibility of an existing power system without the construction of new transmission lines.
There is large, power-intensive industrial development in central Norway; the demand in the region has increased dramatically and is expected to grow even further. The power import capacity to the region has previously been limited due to reasons of system stability. As a remedy, the Norwegian TSO Statnett installed SVCs in the 420/300 kV grid, each rated at +/-250 Mvar. With the installation of the SVCs, the power import capacity to the region under stable conditions has increased considerably. Another example is near Oslo with a SVC with ±160 Mvar and connected to the 420-kV system to stabilize the voltage during faults. The SVCs are equipped for damping of system electro-mechanical oscillations by means of Power Oscillation Dampers based on active power measurements. In addition, they are equipped with Q Optimizers, which enables coordinated control between the SVCs and mechanically switched shunt capacitors also employed in the grid. This ensures that the SVCs have maximum dynamic capability available to provide fast response to counteract grid disturbances. Finally, Statnett is working on implementing Wide Area Monitoring Protection and Control to manage this task. This is described later in this report.

Connection with offshore installations (for offshore wind or oil/gas platforms) requires cables. For this reason there is a technical and economical limit to the distance that can be served with AC cables. The capacitive, or charging, current has a limiting effect on cable rating capacity (MW). In case of long cable circuits, the compensation of charging current requires installation of shunt reactors connected at one or both ends of the cable. When connecting an offshore wind park with a longer cable, it may be a better solution to include the shunt...
reactor in a SVC. The integration of high amounts of wind power into an existing power system will need investments to increase the hosting capacity. This may be a new line, FACTS or storage. One case study of this is found in Texas. In 2008, the Public Utility Commission of Texas (PUC) assigned close to 5 billion USD for CREZ (competitive renewable energy zone) transmission projects to be constructed by seven transmission and distribution utilities. The project will eventually transmit 18,456 megawatts (MW) of wind power from West Texas and the Panhandle to highly populated metropolitan areas of the state. See [http://www.texascrezprojects.com/](http://www.texascrezprojects.com/)

![FIG. 23 CREZ program (PUC)](image1)

One possibility with STATCOM is to include battery storage for distribution. UK Power Networks has installed a DynaPeaQ dynamic energy storage system at a site in Norfolk, England in collaboration with ABB and Durham University. It is located in an 11 kV grid with considerable penetration of wind power. Its purpose is to test the functionality of the concept in conjunction with a small wind farm and test applications, such as leveling out short time power fluctuations from the wind farm, and to store energy during low demand and release it to the grid during high demand. The Energy Storage Systems (ESS) DynaPeaQ has a dynamic reactive power range from 600 kvar inductive to 725 kvar capacitive. The battery storage connected to the DC side of the VSC can deliver 200 kW for one hour, or 600 kW for a short period.

![FIG. 24 SVC with battery storage (ABB)](image2)
HVDC MATTERS!

HVAC technology supported with SVC is feasible for both onshore and offshore installations of wind parks. For larger onshore wind parks, SVC, STATCOM, as well as series compensation, may be required to transport the power and maintain power quality. There is, however, a technical-economical limit for AC cable connections. The longest offshore cable project in the world is to build a power link between a new oil and gas field being developed by Total E&P Norge AS in the North Sea and the Norwegian power grid. The field receives its electricity feed through the world’s longest subsea AC link – a 162 kilometer long, high-voltage sub-sea power cable that lies at its deepest point 370 meters below sea level. The 145 kilovolt high-voltage three-core polymeric insulated (XLPE) sub-sea cable supplies up to 55 megawatts of AC (alternating current) power from the mainland grid to the new Martin Linge field. The cable includes fiber optic links to control the facilities from shore. For longer cables, whether they are under ground or subsea, between countries or islands, HVAC is no longer feasible. But HVDC is!

Hydropower resources are often located far away from main consumption. As described earlier, it is possible to transmit more power over longer distances with lower losses using a higher voltage. Since the introduction of 400 kV HVAC and 100 kV HVDC in Sweden at the beginning of the 1950s, the voltage levels have increased significantly. The first “almost” 800 kV system in the world was built in 1975 by Hydro Quebec in Canada for 735 kV.

The line, stretching from the Manic-Outardes dam to the Levis substation, was brought into service on November 29, 1965. This was the beginning of power transmission from several distant hydropower plants such as Churchill Falls and James Bay.

The HQ 800 kV system was built to transmit hydropower over long distances. FACTS (SVC and series compensation) was later added to further increase the power transmission capability. As described earlier, HVDC is another alternative for transmission which is needed when using long cables. When it comes to long distance transmission with over head transmission lines, HVDC has the advantage that DC does not see the reactance in the line which causes AC voltage drop. Furthermore, a DC transmission line with two conductors for plus and minus requires less space than one HVAC line. In addition, one HVDC line may transmit the same power as several HVAC lines. HVDC does, however, add the cost of the HVDC stations. In the end, it will be an economic evaluation if HVAC or HVDC is less costly regarding investment and losses. The break even distance may differ but around 500 to 1000 km HVDC is competitive for remote hydro.

Another technology breakthrough for HVDC was needed to bring hydropower to Los Angeles. A series compensated 500 kV system was the backbone of transmission hydropower from the North West down to California and the main load centre in Los Angeles. After the introduction of HVDC in Sweden, and later in other countries, this technology was selected for what was called the Pacific Intertie. Since the start of the project in 1965, this HVDC link has been upgraded several times. When the first phase was commissioned in 1970 it was the longest and largest HVDC link in the world, with a 1360 km long transmission line. While earlier projects had been for subsea interconnectors, this was the first HVDC link specifically built for hydropower and also the first “embedded HVDC” to stabilize a parallel HVAC system. The voltage has been upgraded from the original ± 400 kV ->± 500-> to ± 560 kV. The power has been increased from 1440 MW to3800 MW.

Although Pacific Intertie was a technological breakthrough, it was the FURNAS Transmission system between Itaipu, then the largest hydropower station in the world, and the load centre in Sao Paulo that became the largest transmission project for many years. It has a total rated power of 6 300 MW and a voltage of ±600 kV DC. The Itaipu HVDC transmission consists of
two bipolar HVDC transmission lines bringing power generated at 50 Hz in the 12 600 MW Itaipu hydropower plant, owned by Itaipu Binacional, to the 60 Hz network in São Paulo, in the industrial centre of Brazil. HVDC was chosen basically for two reasons: partly to supply power from the 50 Hz generators to the 60 Hz system, and partly because an HVDC link was economically preferable for the long distance involved. In addition, three parallel series compensated 800 kV transmission lines transmit the Brazilian part of the Itaipu plant which means both FACTS and HVDC are utilized.

FIG. 25 The development of HVAC and HVDC

Commercial UHVAC was introduced by HQ in Canada for 735 KV in 1965 and later at AEP in the USA for the 765,000-volt transmission line, between Baker and Marquis stations in Kentucky and Ohio, respectively, in 1969 and the first series compensated 765 KV for FURNAS in Brazil. AEP continued the development of UHV technology in cooperation with ASEA (Now ABB). In 1976 the first sustained operation of ultra-high-voltage (UHV) line with transformer at 2,000,000 volts was tested at the AEP/ASEA UHV Research Center at North Liberty, Indiana, USA. Test installations and single lines were built also in other countries such as a 1,150 kV circuit in the former USSR in 1985. 1000 kV was built in Japan but, like the installation in Russia, they now operate it at 500 kV.

All major steps of HVAC and HVDC voltages have been initiated by transmission of large amounts of hydropower. This is why the latest increases of transmission voltages have been to connect hydropower in China and India. ABB started the development of UHVDC systems in the early 2000s with testing of each main component as well as full scale testing at STRI in Ludvika, Sweden in 2008-2009 for 850 kV and later 1050 kV.

FIG 26a. Testing of UHVDC at STRI
In July 2010, the Xiangjiaba - Shanghai transmission was the first UHVDC (Ultra High Voltage Direct Current) project to go into commercial operation in the world. State Grid Corporation of China (SGCC) is the owner and ABB was the main technology supplier. The project was completed in 30 months, one year ahead of schedule. The ±800 kV Xiangjiaba-Shanghai UHVDC link, with a rated power of 6 400 MW, has the capacity to transmit up to 7 200 MW of power from the Xiangjiaba hydropower plant, located in the southwest of the country, to Shanghai, China's leading industrial and commercial center, approximately 2,000 kilometers away. A UHVAC system for 1000 kV was deployed in parallel to the UHVDC system. 1100 kV rated GIS was developed for the 1000 kV UHVAC grid and tested at STRI in Ludvika.

Another example is the 2,090 km Jinping - Sunan power link which will transport clean hydropower from power stations in the Yalong river in the Sichuan province in central-western China to the highly industrialized coastal area in the eastern province of Jiangsu. The UHVDC link will have a rated capacity of 7,200 MW and 7,600 MW continuous overload. The 2-hour overload is 7,920 MW and the thyristors then handle a record-breaking DC-current of more than 5,000 Amperes. This is the most powerful transmission line in the world going into service in 2013 in China. It was done by ABB together with CEPRI and other Chinese partners. And even higher levels are being developed.

The North Eastern region of India has an abundance of hydropower resources, approximately 65 000 MW. The resources are scattered over a large area, whereas load centers are located several hundreds and even thousands of kilometers away. The power has to pass through the so-called "chicken neck area", a very narrow patch of land (22 km width x 18 km of length) in the state of West Bengal having borders with Nepal on one side and Bangladesh on the other.
The ±800 kV North-East Agra UHVDC link will have a record 8,000 MW converter capacity, including a 2,000 MW redundancy, to transmit clean hydroelectric power from the north-eastern and eastern region of India to the city of Agra across a distance of 1,728 kilometers.

ABB has been selected by Powergrid Corporation of India Ltd. to deliver the world’s first multi-terminal UHVDC transmission link, worth $900 million. The link is called the ±800 kV, 6,000 MW HVDC Multi Terminal NER/ER - NR/WR Interconnector – I Project (NEA800 in short and also known as North East - Agra HVDC). The link comprises four terminals located at three converter stations with a 33% continuous overload rating and the power transmission system will thus have the possibility to convert 8,000 MW – which is the largest HVDC transmission ever built. The first stage of the system is scheduled to be operational in 2014 and the second stage in 2015. The development of even higher voltages is planned in India (1200 kV UHVAC) and China (1100 kV UHVDC).

A large number of HVDC systems are in operation around the world and their performance is followed and reported by CIGRE. This technology is “mature” although it is still being developed to higher UHVDC systems and multi terminal applications. There are still large HVDC and UHVDC projects planned and being built to harvest large hydropower resources in Brazil, India, Africa and especially China. In China, UHVDC is also planned to connect to remote coal resources as well as large wind parks. This so-called “classic” HVDC technology is based on thyristors technology and is supported by the major International suppliers. Although this HVDC technology has many advantages, it could improve with transistors!

The HVDC VSC technology (with IGBT transistors instead of thyristors) was first demonstrated by ABB in 1997 and commercially introduced for Gotland in 1999. For about ten years, ABB was the only supplier but now this concept is offered by ABB, Alstom Grid, Siemens and CEPRI. New and larger applications are in use and there are ongoing discussions on larger HVDC grids.

Significant information has been provided about ABB design and application for the obvious reasons explained above. ABB has twelve HVDC VSC systems in operation while Siemens has one and Alstom Grid none. ABB has published a wide range of information while details from the other manufacturers are scarce. Earlier publications from CIGRE and others were also limited to ABB design for the same reasons. However three reports have recently been published, FOSG, “Roadmap to the Supergrid Technologies” (March 2012 and updated March 2013), CIGRE 492 “Voltage Source Converter (VSC) HVDC for Power Transmission – Economic Aspects and Comparison with other AC and DC technologies” (April 2012), CENELEC, “Technical Guidelines for first HVDC Grids” (December 2012).
FIG 28 Comparison between HVDC CSC and HVDC VSC (Siemens, Alstom Grid, STRI)

The introduction of HVDC VSC technology provided several advantages compared to the classic HVDC CSC technology. Simply put, HVDC VSC had the same functionality as HVDC and FACTS and could control power and voltage through the possibility to change the direction of active and reactive power. Just as simply, HVDC VSC can be compared with a combined generator and motor producing or consuming power.

FIG 29. The development of HVDC- VSC (ABB)

For more than ten years ABB was the sole supplier, until 2010 when Siemens put Transbay cable into service in the USA. This means the operational experience of HVDC VSC technology is mainly based on ABB installations. While operational experience of Classic HVDC is collected annually by CIGRE, as presented at CIGRE 2012 in Paris in
B4_113_2012, the published experience of HVDC VSC is more limited. However, in a 2010 CIGRE paper based on operations in Australia and the USA, the “Energy Availability” during the period 2003-2009 was of the same magnitude as for HVDC Classic (95-99%). The HVDC-VSC technology is evolving for higher voltages and higher power ratings. Since most of these applications are for cables, it is the cable rating that is the main dimensioning criteria. The total capability, reliability and availability will be determined by all components in the HVDC system, including transformers and switchgear but the HVDC converters and the cables are the most critical.

![Testing of HVDC VSC converter and HVDC PEX cable (STRI)](image)

FIG 30. Testing of HVDC VSC converter and HVDC PEX cable (STRI)

The capacity of both classic HVDC CSC and the novel HVDC VSC has increased rapidly during the last ten years and the present status I shown in the figure below. OHL applications do not have the same limitation as cables. The old mass impregnated cables (MIND) are available for higher ratings than the plastic design (PEX).

![Capacity of HVDC Systems](image)

FIG 31. Capacity for HVDC-CSC and HVDC- VSC (ABB)

The figure below summarizes the present capabilities. These capabilities, however, are affected by the configuration type used for the HVDC system: monopole or bi-pole.
The above figure shows the typical configurations used for HVDC CSC classic. Monopoles have normally been used for subsea cable connections. Early projects had ground return through the sea. Recent projects use a low voltage metallic return. The NORNED and BRITNED projects are examples of bi-poles without ground return. Bi-poles are the common connection for OHL. A bi-pole can transmit twice the power of a monopole. A further advantage of the bi-pole is the redundancy when it can be operated as a monopole in case of a failure in the other pole or circuit. Monopole operation has to be provided with a ground return path. This can be done with an additional metallic circuit or with ground electrodes.

The above symmetrical monopole configuration is used in all existing HVDC VSC applications except Valhall, Norway and Caprivi Link, Namibia. This means it is operated with plus and minus voltage with a grounded midpoint. Still, it cannot be operated with only one circuit. For this a full bi-pole configuration has to be used.

HVDC-VSC is now deployed for different applications including the Caprivi Link OHL in Namibia. Major generation situated in South Africa consists mainly of thermal power stations, while the central area (Zimbabwe and Zambia) contain a large proportion of hydropower stations. The western corridor (Namibia) has only small hydro and thermal generation. The Caprivi Link forms a very important regional interconnection in the South African Power Pool.
by providing a central-west interconnection. The scheme utilizes Voltage Source Converter (VSC) technology and is the first scheme to use VSC technology with overhead lines. The scheme has also been designed for earth return operation with earth electrodes. Today, the Caprivi Link converter stations can provide up to ±200Mvar SVC capability throughout nearly the entire power transfer range from 0-300MW operating as monopoles. However, it has been designed to be upgraded to a bi-pole. This is to increase the power, but also for improved redundancy since overhead lines are more exposed to faults, e.g. from lightening, compared to cables.

Another method to achieve higher power and redundancy is to duplicate the HVDC link. This was done for the Itaipu project in Brazil in the 1980s with two links for ±600 kV with a capacity for 3150 MW each. Brazil has more large hydropower resources but they are located far away from rapidly growing consumption centres. When the Trio Madeira project was planned, the experience from Itaipu was very valuable and after evaluating different options, a similar HVDC design was selected. The Rio Madeira HVDC System comprises a total of 7100 MW of converter capacity required to transmit the power from the hydroelectric plants of Santo Antonio and Jirau, located on the Madeira river close to Porto Velho, to local load centres and to the main consuming areas in south-eastern Brazil. The two trunk transmission lines to the south-east are rated ± 600 kV and extend over 2350 km, which was the longest transmission link in the world. This capacity is divided among two bipolar transmission links rated 3150 MW each (ABB and Alstom) and two back-to-back blocks of 400 MW each (ABB), giving a total of 7100 MW. Capacitor commutated converter (CCC) type back-to-back converters are used instead of conventional-type converters for local load. This provides reactive power support and eliminates the need for synchronized compensation.
The Rio Madeira project includes two vendors (ABB and Alstom) and several HVDC converters as different HVDC technologies (CSC and CCC) which all have to be coordinated in operation. Another challenge for coordination is the operation of a multiterminal system. The first multi-terminal HVDC system was built by ABB for the Quebec-New England Phase II HVDC project. The power is generated at La Grande II hydropower station, converted into DC at the Radisson converter station, and transmitted over the multi-terminal system to load centers in Montreal and Boston. The first multi terminal UHVDC link in India has been described earlier in this report. The HVDC CSC Classic technology has consequently been further developed for higher voltages and capacities including multi terminal applications. The HVDC VSC technology still offers additional advantages for power system operation. This includes the feasibility for multi terminal applications and DC grid systems.

In Transbay, Siemens introduced the multi level design. ABB introduced as well a cascaded multi level design which is now used for all new projects. Alstom Grid became the third vendor to introduce HVDC VSC although no project is in operation besides a small test installation. Sydvästlänken in Sweden is the first commercial project. The technical design of these three vendors differs, but they can all be called “multi level”. There are now a large number of projects planned and in progress, including large HVDC offshore installations using this technology with limited experience.

![Simulated multiterminal HVDC system (STRI)](image)

Although most HVDC VSC applications in the near future are radial point-to-point connections, it is necessary to be able to integrate at a later date several such links in a multi terminal application evolving to a larger DC grid. This was investigated within three projects on HVDC VSC technology performed by STRI for Statnett and Svenska Kraftnät. Different types of configurations, HVDC VSC technology and fast DC breakers, were included in the studies. One of the studied configurations included three off shore nodes connected to both wind power and load from a gas/oil offshore platform. This five terminal link should furthermore have the ability to transfer power between the end onshore HVDC converters (see figure 31). The other studied configuration was for an embedded HVDC VSC multi terminal connection for both cables and OHL. The above studies were a state-of-the-art survey of available HVDC VSC technologies and concerns and not for a specific project. It also included a survey to the major HVDC manufacturers; ABB, Alstom and Siemens. Some of the lessons learned are now being implemented in three HVDC VSC projects for Svenska Kraftnät and Statnett. All three can be designated as further advances of the VSC technology.

The TSO's of Sweden, Svenska Kraftnät and Lithuania’s LITGRID turtas have awarded ABB contracts to supply a new HVDC Light link between the two countries. The transmission rated 700 MW links the electricity networks of the three Baltic States with those of the Nordic countries. When it goes into operation in 2015 it will be the longest HVDC VSC cable connection with a 400 km long sea cable route, land cable routes of 40 km on the Swedish
side and 10 km on the Lithuanian side. The 700 MW and ±300 kV link is designed for the possibility of future additional terminals.

Another “first” is the ABB supply of additional HVDC VSC technology for the Skagerak link. The Skagerrak 4 HVDC Light link will be operated in a bipole configuration with the Skagerrak 3 HVDC Classic link. This is the first time a Classic and a Light link will be tied together in such a bipole configuration. This is possible because the same advanced control system is used for all terminals. With the Skagerrak 4 link, Norway and Denmark will have a total power exchange possibility of 1,640 MW. The link is owned by Statnett in Norway, and Energinet.dk in Denmark.

A major VSC contract has recently been awarded in Sweden by Svenska Kraftnät to ALSTOM Grid to supply the first stage of a 1440 MW onshore HVDC multi-terminal connection. This project is known as the ‘South-West Link’, and will consist of two parallel circuits, each comprising 720 MW, ±300 kV symmetrical monopoles. The transmission conductors will be a combination of both underground cable (Supplied by ABB) and overhead line. The first phase of the project is to build the scheme with only four stations, two at Barkeryd and two at Hurva. In a future phase the scheme was originally planned to expand with additional terminals, extending close to Oslo, in Norway, further increasing the flexibility of the Nordic power pool.

These significant challenges for new and more demanding applications using HVDC VSC, such as to connect offshore wind, are well known and described in several reports including the aforementioned reports from STRI for Svenska Kraftnät and Statnett which currently deploy HVDC VSC technology in three new projects. CIGRE has presented several reports, and the latest HVDC grid feasibility study is to be published in Q2, 2013. In addition, there are several new CIGRE working groups. The work within the so-called “Adamowitsch group” for DG Energy and “The North Seas Countries’ Offshore Grid Initiative (NSCGI), including a final report on “Grid Configuration” published November 16, 2012, give valuable inputs as well as the earlier report on “Offshore Transmission Technology”, published by ENSTO-E in November, 2011. The ENSTO-E North Sea group actively works on these challenges.

The conclusion is that HVDC VSC technology offers new features needed for the demanding new applications such as offshore wind power. There are many challenges for the reliable and secure deployment of this technology. This has been described by STRI and DNV in common papers on “Risk Based Approach for Offshore Grid Development” and is now further developed with many stakeholders in a Joint Industry Project (JIP) on Technology Qualification for offshore HVDC. The goal of this project is to develop a Recommended Practice (RP) that specifies a procedure for Technology Qualification that can prove that offshore HVDC transmission technologies are suitable for their intended use. Consequently, the successful deployment of HVDC technology is an ongoing joint effort including many
stake holders, CIGRE, CENELEC, JIP, the Friends of the Supergrid (FOSG), etc. A list of HVDC-VSC projects in service and in progress is enclosed as appendix to this report.

A large number of offshore wind farms, as well as subsea cable links with point-to-point HVDC connections, is now in different stages of implementation. The possibility to create an offshore DC grid, and a continental DC grid as well, has been discussed for several years. On November 16, 2012, the "North Seas Countries' Offshore Grid Initiative (NSCOGI)" presented their initial findings; “The information contained in this report aims to evaluate the long-term development of an offshore grid structure in the North Seas. While some coordination already exists nationally with the integrated connection of a number of offshore wind parks (e.g. Germany and Great Britain) and between nations in the development of interconnectors, this report seeks to answer the question of how best to exploit future offshore generation resources – by continuing to ‘go it alone’, or by ‘doing it together’? It therefore provides a view on how a meshed offshore grid might develop over the period 2020 to 2030 as the countries in the North Seas region advance towards a low carbon energy future.”

The following conclusion was reached: “It should be recognized that the radial and meshed design strategies represent extreme ends of the spectrum of approaches. Any integrated offshore grid is likely to develop in a stepwise manner with coordinated near-shore wind connections and point-to-point interconnectors an essential first step……. At today’s stage any future offshore grid is expected to be developed gradually based on robust business cases for individual projects rather than being built from any blueprint for the future.”

The Friends of the Supergrid (FOSG) is a group of companies which have a mutual interest to promote and influence the policy and regulatory framework required to enable large-scale interconnection in Europe. They promote the faster implementation of a DC grid. In a speech and press release on 19 March, Friends of the Supergrid Chairman, Mr. Marcello del Brenna, called on EU policy makers to deliver a single market in electricity this decade, and to put in place the regulatory framework to enable large scale interconnection between Member States. This will provide real benefit to consumers across the EU, and capture significant economic benefit for European industry. One conclusion of Supergrid 2013 was: Technology has never been, is not, and will never be the bottleneck to Supergrid delivery.”

Two reports from FOSG were released in March 2013 covering a road map and a summary of ongoing activities. Although not precluding overhead line transmission, the first report focuses on the availability of underground and subsea cable technology, as this is considered to be one of the core technologies on which a future Supergrid would be based. The other core technology is the Voltage Source Converter (VSC) variant of HVDC, which is now available from multiple manufacturers. New control and protection techniques are required to implement such a widespread HVDC grid. Two key technologies still under development, either at the research phase or at the prototype testing phase, are identified: fast acting DC circuit breakers and DC/DC converters.

ABB presented a solution at CIGRE in Bologna in 2011 with a hybrid DC breaker for up to 16 kA with losses less than 0.01 % and operation in less than 2 ms. This was possible with a hybrid design. In a press release in February 2013, Alstom presented the results from their design test for RTE of a fast breaker for 3 kA the large scale demonstration project TWENTIES supported by the FP7 programme of the European Commission.
Even though this needs IGBT components as well as other equipment, it is less complex than the full bridge solution. Which one of ABB, Alstom or Siemens variant for DC breaking will be most competitive is up to the users to decide.

The second Report summarizes the work of CIGRE and CENELEC in Supergrid technology. It presents an overview of the present “state of the art” across issues such as: testing of high voltage cables for DC applications, DC grid design, standardization of DC voltages, HVDC grid codes and converters, voltage control and protection.
4.2 ICT for Network Management & Automation

What we today call “Information and Communication Technology (ICT)” has been used for Power System Management for many decades. SCADA systems for remote control were introduced in the late 1960s and early 1970s in many countries to operate and balance the power system efficiently. The functionality of these systems has evolved together with the development of computers and communication. Advanced monitoring, protection, control and automation of substations have followed this evolution. The basic requirements of high reliability with the required sensitivity, speed and selectivity for fault detection and fault clearing are not new. However, the development of the power system has added to the above requirements.

In the older power systems mainly, in Europe and North America, the infrastructure is ageing together with that the system is getting larger, more complex and operated closer to its limits. In rapidly growing power systems the load demand is a race with new installations. Deployment of higher voltages, FACTS and HVDC give new possibilities for controllability of power flows and emergency schemes. Larger black outs in recent years in several countries have demonstrated the dependence modern society has on electricity and also how vulnerable a more complex and interconnected system is. Compared to most other processes, the power system is different because it is ONE interconnected process covering larger geographical areas with an increasing number of influencing equipment and sub processes that have to be in perfect balance at all times.

The rapid development of RES, especially as variable generation from wind and solar energy, will stress this system even further. To balance this system, an increasing number of generating units are integrated in the system at various points which, unless controlled, create new load flow patterns and unpredictable variations. In many countries, this balancing and scheduling had earlier been done by one entity responsible for generation, transmission and, sometimes, also distribution. In a deregulated power system, this is handled by different companies and organizations where trading of electricity is a separate process similar to the stock market with different prices being quoted at present and for the future.

The Transmission System Operators have the responsibility to maintain a reliable power system operation despite these new influencing factors. This requires an even stronger and smarter power system. Investments in the transmission system are costly and take time. ENSTO-E is regularly presenting their ten year plan for the system expansion. The latest TYNDP showed that more than 100 bottle necks had been identified in the European system due mainly to the introduction of RES together with trading of electricity. All of this will require the full utilization by IEC of advanced ICT for what now is called “Power Utility Automation”. Parallel with the power grid, there will be the ICT-grid interconnecting different stakeholders for sharing information as well as initiating fast automatic processes.

It can be seen as an Internet for the power system although with even higher requirements on speed, quality and security. A “bug” or a hacker intruder will never be allowed to close down a complete power system. The conflicting requirements of many to have increased and faster access with cyber security is therefore a challenge. Finally, another critical challenge is “interoperability”. Earlier, different vendors and users had their own systems and versions which required “protocol converters” to allow exchange of raw data within one system. The new challenge is that the number of data points, the quality and speed of data, the number of applications and users are multiplying in what we now call “Smart Grids”. A common “frame work” is needed with a common “data model” and “language” to exchange information rapidly and reliably. The Smart Grid requires standardization with future proof
interoperability. That is a BIG task with many stake holders. It requires a joint effort by manufacturers, users and standardization organizations.

The deployment of new technology is happening at different speeds in different countries. In emerging economies with rapidly growing power systems, the deployment of new technology is fast while in existing power systems this is slower and has to be interfaced with existing older infrastructure. The following is a summary of a workshop arranged by the U.S. DOE on “Electricity Transmission Systems” in October 2012 which illustrates the challenges faced in the North American transmission grid (emphasis in the original):

“Various technologies being deployed make it possible to produce an overabundance of data, but in some cases there may be insufficient understanding of the quality and usability of some of that information. As an illustration of this issue, the potential for using data streams from phasor measurement units (PMUs) currently deployed to provide system awareness and operations has not been fully realized, inhibiting deployment of additional sensors that may be beneficial. Applications for the PMU data are still very basic and the value proposition for additional sensors has not been demonstrated yet. Further efforts are needed to develop methods to identify, filter, extract, and aggregate useful information from the data for specific applications that are sufficiently flexible to meet requirements over multiple temporal and spatial scales.

Another challenge is developing an adequate information-technology (IT) and communications infrastructure to achieve comprehensive system visibility. The current state of this infrastructure is highly inconsistent across utilities and regions. For example, many utilities have inadequate connectivity from control rooms to substations and field assets. This issue is driving a redefinition of the concept of a “Smart Grid” beyond deployment of smart meters to encompass IT systems in general. More specifically, a modernized grid will require cost-effective, reliable and commercially available monitoring hardware that communicates between diverse products and users. These hardware devices must be capable of communicating automated, detailed information to help operators understand the source of a fault or a potential fault, the availability of system flexibility, and other system characteristics. Interoperability between both new and existing products, equipment, and technologies is a critical requirement to ensure clear and efficient interactions between devices and systems.

The lack of standardized communication protocols is another challenge to grid visibility. Equipment vendors often use different data transfer techniques—which are often proprietary—that cannot communicate with other devices and systems without added hardware or software, raising overall costs.

The transmission system currently lacks visibility into the distribution network, especially of deployed distributed resources. As these technologies are added in large quantities to distribution systems, the aggregate effects will impact the transmission system. Integration of these inputs—with data that is validated in real-time—will provide the visibility that transmission operators need to react and respond to critical events with a level of efficiency and accuracy that is unavailable to them now.

Knowledge of what neighboring entities are doing with respect to unit status, grid topology, transactions, control schemes, etc., is needed to facilitate wide-area understanding. Ultimately, issues associated with ownership and governance of data needs to be resolved to effectively coordinate data sharing and utilization. The key issues that need to be addressed include who can see the data, who can use the data, what they can do with it, who will manage it, and who will pay for its management. Furthermore, utilities are obligated to protect data confidentiality and that additional level of complexity must be considered in the design of a modern system. Cyber security is another element that must be incorporated
into every facet of information and communication systems for a future grid.

The prioritized challenges are summarized at the workshop as: “areas of grid visibility (the ability to “see” an event or condition), grid understanding (the ability to “know” what is happening or about to happen), and grid flexibility (the ability to “do” something appropriate in response).”

Today there are a number of ongoing Smart Grid activities and the understanding of what Smart Grid includes still differs. However, there is agreement on the increasing importance of Information and Communication Technology (ICT) for the Smart and Strong Power System. The increase of variable generation from Renewable Energy Sources (RES) such as wind and solar requires increased flexibility and immediate adaptability. Larger disturbances have shown the need for “Visualization” and “Situational Awareness” on what is happening within a more complex power system. There is also a common understanding of the need for standardization and interoperability of ICT as products and “systems of systems”. This is handled globally within IEC as well as within CENELEC (EUROPE) and NIST (USA).

And there are many standards. NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 1.0 in 2010 defined 75 standards as an example. Over 100 IEC Standards have been identified as relevant to the Smart Grid. A list of the core IEC standards is available at [http://www.iec.ch/smartgrid/standards/](http://www.iec.ch/smartgrid/standards/). The complete list of IEC Standards (by importance and relevant application) is available for download.

In the document above, NIST has also provided a conceptual model showing communication between different domains. In this report we will focus on the domain “Transmission” and to some extent “Operations” for transmission. Version 2.0 was released in February 2012 and a Smart Grid Interoperability Panel (SGIP) has been created. In December 2012 a set of comprehensive documents were provided by the CEN-CENELEC-ETSI Smart Grid Coordination Group (SG-CG). This includes a Smart Grid Architecture Model (SGAM) which is an adaption of the NIST conceptual model for Europe extended with Distributed Energy Resources (DER) as well as a first set of proposed standards.

Interoperability is seen as the key enabler of Smart Grid. Consequently, the proposed SGAM framework needs to inherently address interoperability. To understand interoperability in the context of Smart Grid and architectural models, a definition is given together with requirements for achieving interoperability.

IEC 61850 describes interoperability as “the ability of two or more devices from the same vendor, or different vendors, to exchange information and use that information for correct cooperation”.

In other words, two or more systems (devices or components) are interoperable if they are able to cooperatively perform a specific function by exchanging information.

The Smart Grid Architecture Model (SGAM) Framework consists of the five interoperability layers allowing the representation of entities and their relationships in the context of Smart Grid domains, information management hierarchies and in consideration of interoperability aspects.
In general, power system management distinguishes between the electrical process and information management viewpoints. These viewpoints can be partitioned into the physical domains of the electrical energy conversion chain and the hierarchical zones (or levels) for the management of the electrical process. This Smart Grid plane enables the representation on the levels (hierarchical zones) of which power system management interactions take place between domains or inside a single domain.

CENELEC presented in the same report in December 2012 a “first set of standards” covering the areas shown below. In this report we focus on “Transmission management systems”. HVDC is not included as it already plays an important role in Transmission Systems. HVDC links are already in use for emergency system protection within the Nordic power system. With the deployment of WAMPAC, the ability to control not only FACTS devices but also HVDC and especially HVDC VSC in real time will be an important method to damp oscillations and prevent voltage collapse.
The report is very comprehensive and a guide to the world of standards. As an example, the standards identified for Substation Automation is shown here below. It refers to the work done within IEC TC 57 for IEC 61850. IEC itself has identified the following core standards:

- IEC 61850 (Power Utility Automation)
- IEC 61970 (CIM, Common Information Model Transmission)
- IEC 61968 (CIM, Common Information Model Distribution)
- IEC 62351 (Cyber security)

The same five standards were identified by NIST as core standards but this created an intensive discussion in the U.S. where DNP 3.0 was a defacto standard used by many. This reflected the different history of designing protection and control systems where Europe, and especially the rapidly growing power systems in Asia & South America, favored a system approach while the U.S. practice has been more product focused. DNP 3.0, like IEC 870-5-101, is only subsets of the functionality of IEC 61850 which has a much wider scope and is one of the fundamental standards for a smarter grid. From basically covering only substation automation, this concept now includes a number of different applications. The work with the standard IEC 61850 is unique since a standard is often a matter of fact after development of products and systems. When it comes to the IEC 61850 standard, it enabled the development of technology, products and systems.

The technology evolution during the 1970s for monitoring, protection and control in substation from electromechanical devices to static (solid state) devices basically only replaced function by function, e.g. an over current relay or a distance relay. These devices had output and input relays with contacts as the only method for external communication. With the introduction of microprocessors during the 1980s it was possible to integrate more
functionality in one device and also introduce digital communication to a modem. With more powerful micro processors and digital signal processors it was possible to digitalize analog signals which was the basis for synthesizers and Compact Discs, but then also applied to monitoring, protection and control. Sampling of currents and voltages together with digital (numerical) algorithms gave further possibility to integrate different functionality and store data. This allowed for more information to be communicated, however still normally through a gateway or Remote Terminal Unit to a control centre for SCADA. This is called vertical communication and required a time of 2-3 seconds. A number of different protocols evolved for this straightforward point-to-point communication. Digital fault recorders and fault locators were introducing “sampling” of currents and voltages which made it possible to store information about a disturbance and retrieve this file when needed. COMTRADE was introduced as a de-facto standard file format which allowed these files to be presented, exchanged and even played back by third party tools and testing equipment. However, there was no common protocol to transmit the files.

Process automation was introduced in several industries and this was also implemented for Substation Automation in the mid-1980s. Process automation, including Substation Automation, required fast and reliable exchange of information between different devices in the substation. This is called horizontal communication and requires a common bus communication since several devices on this bus share the same information. This requires shorter times than for SCADA, down to the millisecond level for protection functions. At the beginning of the 1990s, many manufacturers offered products and systems for substation automation. However, these were using proprietary means for communication and the need for an open and standardized protocol was evident.

In 1994 EPRI/IEEE started the Utility Communications Architecture (UCA) with a focus on the station bus. In 1995, IEC TC57 (Technical Committee 57) began work on IEC 61850 to further define station bus communications. In 1995 IEC started work on what should become IEC 61850. A project group of about 60 members from different countries worked in three IEC working groups. In 1997 the work from both groups merged to define a truly global standard. One of the driving arguments was interoperability between different vendors. Another important foundation was the need to standardize, but not prevent, technical development; in other words, to be “future proof.

FIG 42. The structure of IEC 61850
IEC 61850 is not just another protocol but a complete concept and data model to structure how information is communicated throughout the power system. The data model introduces families of names for what is called “Logical Nodes”. This is basically the different functions included in the Substation Automation System. Each function is allowed to be designed differently which it is from different manufacturers. However, it is possible to identify as an example an over current function by its standardized name, PIOC and a distance protection as PDIS, independent of manufacturer. Since the “Logical Nodes” also use a logical designation name convention, P for protection, C for control etc., it is possible to understand this. Another important feature is the use of a common language = Substation Configuration descriptive Language = SCL in XML format and the use of standardized machine readable files to describe the Substation Automation System. Each IED is described in a file called an IED Capability Description. This allows the design of a Substation Automation system without the physical hardware. As an example, the ICD file for ABB and Siemens IEDs are shown.

FIG 43. ICD files from ABB and Siemens

The introduction of IEC 61850 gives many advantages and possibilities to digitalize the power utility monitoring, protection, control and automation system which can then be more reliable, informative, compact and “future proof”. It is a global standard now adopted by all major manufacturers and introduced by many TSOs and DSOs worldwide. It has also the potential to reduce investment and operation costs. However, it has to be understood that the implementation of new products and systems according to this standard will change the traditional work within a traditional power utility. The know-how of both traditional power engineering and IT need to be combined. Engineering, documentation, testing and maintenance will be different. Initial costs to the user include future planning and sufficient training of the work force with proper tools. The challenges will vary depending on the power utility’s own work and outsourcing of tasks, e.g. if substations are purchased “turn-key” with
external service provider for maintenance or if the power utility has in-house engineering and maintenance personnel. Independent of this, the fundamental know-how is required to specify and document a digital system according to IEC 61850. This means to learn the concept, the model, the language and the structure of various files.

The standard for power utility automation, IEC 61850, includes a powerful formal configuration that describes the substation automation system and enables exchange of engineering information between different vendor tools. This Substation Configuration Language (SCL) is delivered as project documentation of IEC 61850 substations. The SCL language itself is based on XML. Through SCL configuration files, the full scope of the language allows an object oriented model of a power utility automation system to be described. Therefore, it is of great importance that everyone working with IEC 61850 based systems is familiar with this “language”, not in detail, but especially the application of each of the different standardized files defining a substation:

• Relations between the switchyard topology (single line diagram) and the functions needed are contained in a .ssd file. (SSD = System Specification Description with single line diagram and function allocation)
• Capability of the devices is the .icd file (ICD = IED Capability Description which describes each IED with LN and data)
• The structure of the Communication system is in the .scd file (SCD = Station Configuration Description is the complete configuration of all IEDs in a substation with process signals and communication structure)
• Allocation of the data model and services to the IEDs is in a .cid file (CID = Configured IED Description include complete IED with vendor specific configuration.)
• The data exchanged between the functions is in the .scd (for entire system) and partially in .cid (relevant parts for a single device)

One of the basic features of the IEC 61850 standard is the separation of functions and hardware. This allows for free allocation of functions to different hardware. When the IEC 61850 standard was first introduced, several manufacturers implemented this standard in existing products with existing functionality. Now, several manufacturers have developed products for IEC 61850. In 2005 ABB introduced the 670 series with what is called “native” implementation of IEC 61850. This is based on a common software library including all monitoring, protection and control functions as defined by the standard which can be configured to a specific hardware platform for a specific application, e.g. a transformer or a
transmission line. The hardware platform and the software are modular, giving the flexibility to configure each IED as before with a limited number of functions or integrate a large number of functions for several objects.

FIG 45 Configuration of IED from a functional library (ABB)

The above figure shows how selected functions, e.g. a distance protection (PDIS), a differential protection (PDIS) or auto reclosing (RREC) can be configured to different sizes of IED hardware. The figure below shows an example for a breaker-and-a-half substation.

FIG 46 Configuration of IEDs for a breaker-and-a-half substation (ABB)

A large number of IEC 61850 based substation automation systems are now in operation. ABB and Siemens state more than 1000 systems from each manufacturer have been delivered. A large number of manufacturers of IEDs and related products and systems offer IEC 61850 compliant products and systems. However, there are still some concerns in the
implementation. These concerns have been reported by independent laboratories, end customers as well as ENSTO-E, GO15 and Phoenix Forum. “Achieving multivendor interoperability” and “Making the Smart Grid concept a practical reality” is the main advantage of IEC 16850 according to the Phoenix Forum questionnaire.

As stated earlier, the digitalization of monitoring, protection and control within the substation and from Remote Terminal Units to SCADA has been progressing for the last thirty years together with the development of ICT and fiber optics. Garbage In Garbage Out (GIGO) is a familiar phrase meaning that the result of every process depends on the quality of what you put in. All processes in the power system are based on the high quality measurement of voltage and currents. This is especially true for current and voltage used for protection, which need to measure and detect a fault in milliseconds. The simplified figure below shows the connection of a duplicated line protection.

FIG 47. Connection between protection and the switchyard

In conventional stations, large current transformers with multiple cores have been installed for the last 100+ years. Voltage Transformers are for larger voltages connected to capacitive dividers. Currents and voltages are connected with several long copper wires between the switchyard and the control room. With the introduction of digital (numerical) IEDs, the analog current connected to the IED was converted to a sampled signal via an A/D converter. This technology is well proven over 30 years. In the 1980s ABB introduced the Digital Optical Instrument Transformer (DOIT) for HVDC and FACTS applications. This basically moved the A/D converter out into the switchyard on high potential and this was connected via optical fibers with sampled values to the control room.

Today, more than 3500 DOIT are installed worldwide. In addition, ABB and other manufacturers developed other types of sensors for medium and low voltage applications as well as for Gas Insulated Substations. Several manufacturers started developing optical sensors for high voltage applications. But most substations were “built as usual” with a 100+ year design with large current transformers (CT) (free standing or in bushings) and voltage transformers (VT) connected with kilometers of copper wires. One main reason was that there was no standard digital sampling and communication, until IEC 61850 9-2 was released.
IEC 61850 9-2 standard also covers possible process bus applications with Merging Units and Non Conventional Instrument Transformers (NCIT). This opens for replacement of oil filled CTs and copper wires with optical transducers and fibers in the switchyard. This gives several advantages with less cabling and less problems with oil as well as the possibility to complete self-supervision and increased personal safety. NCITs, MU and IEDs are covered in different entities within IEC and CIGRE. There is work in progress on each area but not on the complete system integration. Some utilities, e.g. CFE in Mexico, are testing different types of sensors, Merging Units and IEDs from multiple vendors. Here the interoperability is a challenge with even higher complexity.

The ABB 670 series has been released of IEC 61850 9-2 and is used together with None Conventional Instrument Transformers in a Powerlink substation in Australia. The refurbishment project at Loganlea Substation has seen the replacement of the ABB proprietary communication to the existing NCITs with a smart substation automation protection and control system, featuring the world’s first conformance-tested IEC 61850-9-2 merging units and ABB’s protection and control IEDs (intelligent electronic devices). Today this seems to be the only complete substation with IEC 61850 station and process bus which has been described. There are, however, digital substations with NCITs in service in China with unknown functionality.

![FIG 48. Digitalization of the switchyard (ABB)](image)

The majority of substations are “Air Insulated Substations (AIS)” compared to Gas Insulated Substations (GIS). AIS are outdoors with larger switchyards and distances. The replacements of conventional instrument transformers with NCIT and/or Stand Alone Merging Units would here give significant savings in reduced cabling as well as improved self-supervision and improved safety. There are a limited number of NCITs, SAMU and IEDs for IEC 61850 on the market and there is a very limited operational experience. Consequently, there is a need for demonstration sites and pilots to verify the technology as such as well as the interoperability.
The IEC 61850 standard main parts were first published from 2002 to 2005. The standard was the result of nearly ten years of work within IEEE/EPRI on Utility Communications Architecture (UCA) and within working group “Substation Control and Protection Interfaces” of IEC Technical Committee 57. The IEC 61850 standard initial scope was standardization of communication in substation automation systems. The first edition of the standard was primarily related to protection, control and monitoring. From 2009 and onwards, the original parts of the IEC 61850 series have been updated and extended to also cover measurement (including statistical and historical data handling) and power quality. New parts of the standard will also be added to handle condition monitoring. Given the extended scope, today’s naming of the IEC 61850 standard is “Communication networks and systems for power utility automation”. The extended scope of application of the IEC 61850 (and affiliates) is indicated in the above figure.
In this Special Report we have mainly focused on the application of ICT for the Process, Field and Stations zones as defined by SGAM frame work model from CENELEC. There are also interoperability issues within and between Operation, Enterprise and Market zones. The Nordic energy market was one of the first to be deregulated with a formal cooperation between the Nordic Countries. This also included a definition of how to exchange information. A common standard for Electronic Data Interchange (EDI) was developed. The joint, standardized message format used is called EDIFACT. Nordic Ediel Group was formed in 2003 to handle Nordic questions related to data exchange in the energy market. The Nordic Ediel Group was founded after Ediel Nordic Forum was reestablished as a pan European body under the name of ebIX, see www.ebix.org. A Role Model has been developed by ENTSO-E and the associated organizations EFET and ebIX. IEC WG-16 works with standards Standardization as IEC 62325 for Deregulated Market Communications in liaison with ENSTO-E and ebIX. Mission, Scope: Develop Standards for Electricity Market Communications, Market Participants to Market Operator. Intra Market Operator- Use of TC 57 Common Information Model (CIM). In this work two sub teams have been created for “European Style and U.S. style markets”.

The European style is with zonal design and the U.S. style is with nodal design. In a zonal design, the grid is organized into congestion zones. To avoid congestion, the system operator can balance the sources of generation. This reduces congestion, but only between zones and not within zones. Nodal markets are able to address congestion within a zone as well as between zones.

Both ENSTO-E and GO 15 addressed some major concern on lack of interoperability in multivendor solutions as well as lack of third party tools. This illustrates the challenges ahead. Smart Grids will require further standardization TO OBTAIN SEAMLESS AND “FUTURE PROOF” INTEROPERABILITY. But the standard is not enough. It will be a joint effort with many obstacles. The operation and maintenance staff for the T&D systems will face a new technology revolution. They have to be prepared for this. The introduction of fully digital substation automation systems and new functionality for SCADA/EMS with WAMPAC in real time requires not only new skills, but also maintaining the old.

In most “old economy” countries in Europe and North America this will be a step-by-step process combining old and new technologies. A “future proof” and backwards compatible concept is needed. Building new green field systems make it easier. But all companies (TSOs and DSOs) implementing this new technology have to be prepared for this throughout the organization. Training and an implementation strategy are fundamental. This is an investment for the future and it therefore entails initial costs that, with a short time perspective, make it appear more expensive than staying with the older technology. It also requires a system view. Instead of retrofitting piece by piece as before, another challenge is to integrate a complete system with a new working process from engineering, operation and maintenance.

As an example, the integration of IEC 61850 as station bus just to replace existent RTU/SCADA functionality is not economical as such. However, when looking at the integration of new sensors in the substation and with the process bus as well as integration of PMU for WAMPAC, it is possible to save money and space in a future “Smart Substation”. Protection and control of power systems have always required special know-how and experience. It has also been a “conservative” sector of power engineering relying on well proven concepts. Therefore, the introduction of IEC 61850, including the process bus, is a challenge for everyone involved within the organization. It is necessary to take the first step. This means to plan for the future and involve all stakeholders within the organization with know-how of power and ICT, power system security and cyber security.
And once again, this is a joint effort. It will not be solved by finger pointing. We have today a global Internet and global phone system. We communicate with Skype and Facebook. We handle our bank transactions online. So this should not be a technical problem to solve although it is imposing higher requirements on speed and security. When it comes to the even bigger picture of integrating new stakeholders online for the commercial arena this will require other types of functionality. But this is already done on a “massive” scale. We can compare the future Smart Grid with a “MMORPG”, a Massive Multiplayer Online role Playing Game, which many of our children play. Millions of people participate and hundreds of servers already work together in cyberspace - but many in the older generation do not even know what it is. Maybe we can learn something from this?


The concluding remark is a quote from GO 15 from November 2012: “We support the promotion of the worldwide harmonization of standards, which will provide for interoperability of the solutions in a reliable and efficient way. To achieve this, the commitment of competent authorities is needed to support the development of new power grid and information technology infrastructure to provide for a successful and reliable energy transition and to reduce the time required for administrative authorization procedures. We will continue our present work within GO 15 and commit time, effort and resources to support the energy transition in our industry by deploying appropriate equipment and infrastructure with the aim of achieving a robust and reliable power grid and building a low carbon society”.

4.3 Wide Area Monitoring, Protection and Control

When discussing this topic it is appropriate to start with the NIST definition on main transmission applications; Control, Protect, Measure, Record, Stabilize and Optimize. These keywords describe very well the main objectives and motivation for wide area monitoring, protection and control systems.

The basic building block of a Wide area monitoring system is the Phasor Measurement Unit (PMU) that, through GPS time stamping, enables very accurate voltage and current measurements at any location in the power system. Time synchronization makes it possible to measure voltages and currents as phasors that refer to the same system wide angle reference. The PMU is therefore a measurement transducer where the outputs are commonly referred to as “synchrophasors”. The phasor measurements are streamed from their various locations (using different communication solutions) to Phasor Data Concentrators (PDCs) where the data is collected, processed or stored for further applications.

The applications can range from pure storing and simple display of phasor data to advanced post processing of information and possible use in protection and control systems.

Depending on the nature and use of these applications, they are referred to as Wide Area Monitoring Systems (WAMS), Wide Area Protection Systems (WAPS) or Wide Area Control Systems WACS) – or simply WAMPACs.

**Measure**

Based on system wide information from PMUs, it is possible to monitor and observe the state of the power system in a way that was not possible with the conventional SCADA information systems based on RTUs. Wide area monitoring systems (WAMS) have been under development in different places and at different pace during the last 20 years. These are now starting to become mature solutions and suitable for integration in control centre environments. Vendors of control centre systems are also offering solutions with integration of synchrophasor data in their software.

The main purpose of WAMS is to improve the monitoring and observability of the power grid. State estimation in power grids is about estimating voltage phasors at all nodes, and thus providing a valid power flow solution. To replace conventional state estimators, WAMS need to provide additional information or more accurate and reliable information. With a sufficient number of PMUs in the system, the task of state estimation becomes faster and more accurate. By directly measuring voltage phasors we have a state measurement rather than an estimate. The high resolution state measurement can be used to improve situational awareness and understanding of the state of the system in several ways.

- Faster and more accurate indicators can be provided about steady state security of operation. The effect of contingencies in terms of overloads and voltage deviations can very quickly be informed and analyzed.
- The high time resolution of measurements (up to 50 or 60 Hz) enables the implementation of dynamic state observers where the purpose is to provide information about system stability properties. Until now, most attention has been on development of algorithms for power oscillation and voltage stability monitoring. The aim of power oscillation monitoring (POM) is to estimate the natural modes and damping of low frequency inter-area resonances in the power system. Inter-area power oscillations are a true wide area phenomenon. Voltage stability, on the other hand, is considered more of a local problem. However, the identification of a potential voltage instability problem is
- Phasor measurement units are able to provide excellent measurement of system frequency. The importance of system frequency and the quality of frequency control in an AC interconnected power grid is undisputable. Therefore, it is also of highest importance that high quality frequency measurements are available, not only for control purposes, but also for monitoring and information to operators.

**Record**

Enormous amounts of data are collected and can be stored by a Wide area monitoring system. The main challenge is to gain useful information and knowledge from the data. The most widely and successful use of synchrophasor data until now has probably been in conjunction with forensic analysis (fault recording, disturbance analysis) and model validation. There are many examples where phasor data and WAMS information have been used to analyze and explain the root cause and development of high impact system disturbances. Also, measurements from the many smaller disturbances provide useful information, e.g. for model validation purposes. In this way, WAMS have for many years contributed to enhance the understanding of power system dynamics, even though the full breakthrough of using WAMS in the on-line operational environment is yet to come.

**Control, Protect**

In this context we consider control and protection at a system level. Maintaining the overall power system balance through frequency control and congestion management is the main responsibility of the Transmission System Operators. Under critical operating situations there are special emergency controls and protection schemes available, aiming at reducing the system consequences of large disturbances. These tools are usually referred to as System Integrity Protection Schemes (SIPS) or Remedial Actions Schemes (RAS). The most common system protection scheme is probably Under-Frequency Load Shedding (UFLS), but there are many other examples of solutions that take special control actions based on signals like overloads, under voltage or under/over-frequency. The control actions include shedding of loads, tripping of generators, network splitting and fast control of generation or HVDC connections.

A new generation of system protection schemes is foreseen based on phasor measurements, however much more research is needed to develop the robust solution for the future. The potential for development of Wide Area Protection Systems lies, not so much in changing the controls, but in utilizing the accurate and system wide measurements to make better adaptive and more reliable system protection schemes.

One example is the possibility to develop faster and more precise fault location algorithm and component protection.

Another example is smarter and more distributed UFLS. These schemes could be made smoother and more efficient with wide area measurements. In combination with Advanced Metering Infrastructure (AMI) such solutions could possibly become market based where almost any end user can participate.

Grid separation or islanding can be easily detected with system wide phasor measurements. This information can also be utilized for control and protection purposes by intentionally enforcing network splitting or islanding in critical situations. Using the phasor information it is possible to detect abnormal voltage angle differences that may be a risk to security and system stability. Special controls can then be designed to ensure stable island operation while minimizing the need for load shedding.
Such distributed control and protection solutions have the potential to revolutionize frequency control and balance management. We can imagine a future power system where the power balance and primary frequency control is never at serious risk. This is achieved through a combination of WAMS and AMI solutions enabling most consumers and generators to provide primary control services. This implies that from time to time there will be renewable generation that is lost and other times where loads need to be shed. Thus, the power balance will still come at a cost, but a balance will always be found where the control objective would be to minimize the cost of energy not served.

**Stabilize**

In very many of the large interconnected power systems throughout the world, power transfer capabilities are limited primarily due to stability issues. This may be risk of voltage collapse or the risk of sustained power oscillations (that eventually might lead to a collapse).

![Diagram of WAPOD implementation](image)

**FIG 52.** WAPOD implementation. Voltage phasors are measured at two remote locations, and the difference between the voltage angles is used as input to the stabilizing controller of the SVC unit.

The issue of power oscillations is related to damping of the inherent low frequency inter-area modes of the power system and is normally improved by the use of special controls on generators and FACTS devices, referred to as power system stabilizers (PSSs). The conventional power system stabilizer, however, is local control (using local measurements), while power oscillation damping can be a system wide problem. This has been a main motivation behind a lot of research work to develop Wide Area Power Oscillation Damping (WAPOD) controllers. The idea behind the WAPOD is to optimize and coordinate the stabilizing controls by utilizing system wide phasor measurements. With a number of PMUs available it is possible to choose one or a combination of measurements that provide the best observability of the mode to be damped. By implementing the controls in different units (e.g. FACTS devices) having the best controllability of the particular mode, the overall most efficient solution can be found. If there are several low damped modes in the system, it is also easier to design a coordinated control solution. Fig. 39 shows an example of a WAPOD...
solution that has been implemented and tested by Statnett on an SVC unit in Southern Norway.

**Optimize**
Wide Area Controls related to the enhancement of voltage stability properties are somewhat less interesting, considering the more local nature of this problem. However, as stated above the identification of a potential voltage instability problem is difficult and with the availability of phasor measurements at different locations it is possible to make excellent state estimates that can also be utilized for control purposes. The control objective in this case would be to optimize the use of reactive power assets, for example, through coordinated secondary voltage control. With respect to voltage stability, a main objective is the ability to minimize use of reactive compensation in order to maximize the available reactive reserves.

A general objective is to optimize system utilization by combining wide area measurements in coordinated control solutions. This is all about taking advantage of the superior observability provided by WAMS and execution of control where it is most efficient.

**Cyber security and ICT challenges**
The whole concept of Wide Area Monitoring, Control and Protection relies on distributed measurements as well as control actions. Therefore, it depends heavily on communication infrastructure and available ICT solutions. This includes the ICT technology as such and the issue of managing the enormous amounts of data that becomes available.

These aspects constitute major challenges and may be regarded as main vulnerabilities of WAMPACs. In addition to managing the data and information to develop useful applications, there are many questions to be addressed.

What about cyber security? The issue of *spoofing* has been raised. To what extent is it possible to generate false GPS (or other time synchronizing) signals. What are the possible threats related to this and how is it possible to protect against it? What should be the requirements for internal clocks and reliability of the PMUs and communication systems?

Standardization and interoperability will certainly be important for further development in this area.
5 Conclusions and Recommendations

5.1 Deployment of smarter & stronger transmission infrastructure

THE FUTURE IS ELECTRIC!

Energy is vitally important for future economic growth, and a clean and efficient energy system is a high priority for all countries. Electricity is assuming an increased share as a primary energy carrier for three main reasons:

- There is an increasing need for electricity for old and new applications (such as computers, cell phones, air conditioning, electric vehicles etc.) and there are more than one billion people in the world without electricity, and many more with insufficient electricity.

- There is an urgent need to decarbonise the energy system with increased use of RES and other clean energy sources with electricity as the energy carrier.

- There is a need to make energy consumption more efficient and here electricity offers new and smarter solutions to reduce primary energy consumption.

SMART & STRONG T&D SYSTEMS ARE NEEDED TO KEEP THE LIGHTS ON!

Increased electrification will require a strong and smart electricity grid to manage uncertainty and variability for three main reasons:

- Connection of large RES (hydro, wind, solar) facilities from remote regions, and growth of mega-cities will require long and powerful transmission links between generation and consumption areas and additional infrastructure for storage, balancing and reserves.

- Large installations of Intermittent power generation from Distributed Energy Resources (DER) based on solar and wind, as well as customer participation with demand response will require a more intelligent operation of the transmission and distribution (T&D) grid.

- Many countries have an ageing T&D infrastructure which requires significant modernization and strengthening for the Smart Grid of tomorrow.

A SYSTEM VIEW IS NEEDED

Smart T&D infrastructure investments are the most efficient part of the least-cost solution for a global clean energy society! The increased electrification and complexity of supply and demand requires a holistic system approach for Transmission and Distribution development with connected supply and demand for the following three reasons:

- The electric power system is ONE interactive system in which supply and demand must be continuously balanced in real time to maintain voltage and frequency within strict limits. This requires increased knowledge and monitoring of system behavior and wide area implementation of information and communication technology (ICT) for aggregation of data from smart meters, synchrophasor measurements and other sources, together with increased flexibility from power electronics such as FACTS and HVDC.

- The increased connection of large numbers of variable RES, which have little or no inertia, creates a paradigm shift for power system operation with basically unpredictable and rapidly fluctuating conditions requiring instantaneous system wide compensation and balancing of
frequency and voltage.

- With more DER, Distributed Energy Sources, and customer participation with demand response sometimes in combination as “Prosumers”, the interaction between Transmission and Distribution will increase substantially.

YES WE HAVE THE TECHNOLOGY FOR THE SMART & STRONG GRID

The basic technology for transmission like FACTS and HVDC was already introduced in the 1950s and the first “Digital substations” were deployed in the 1980s. Still, most established economies continued to build power systems as before. One important reason was naturally that there were no strong drivers to replace a functioning, hundred year old analog and electro mechanical technology with something new. Now there are! To successfully implement a new low carbon energy system, we need the smart and strong grid. The technology within Power Electronics and ICT has, however, been evolving rapidly during the last ten years partly driven by the expanding power systems in the BRICS countries but also by the rapid deployment of offshore wind. We have a global challenge including both old and new economies, but these challenges differ between regions, countries and even within countries. There is no SINGLE universal solution. But there is now a new portfolio of flexible tools which can be applied to meet these different requirements.

We need a smarter and stronger Power T&D grid in order to handle larger and more varied power flows. This requires the building of new HVAC transmission lines which may not only take a long time, but may also meet with resistance. The good news is that there are possibilities to build more compact transmission lines and, for shorter distances, underground cables can be employed. There are also several methods available to increase the power on existing lines by increasing the voltage or increasing the current. The uprating of 300 kV to 400 kV in Norway is one example. This requires investments in new insulators and/or new conductors but is much less expensive and much faster than building a new line. There are also possibilities with “Dynamic Line Rating” or “Flexible Line Management” when the power flow can be increased with lower ambient temperatures.

![FIG 53. Comparison between HVDC and HVAC with FACTS/SSC (FOSG)](image)

Flexibility is the key requirement for our future clean energy power system. Recent developments in Power Electronics with FACTS and HVDC have given us new tools to implement this flexibility for the smart and strong power system. FACTS and HVDC have traditionally been used to allow transmission over long distances from hydropower. This will also be necessary in the future as currently being done on a large scale in India, China and
Brazil. FACTS, HVDC and especially HVDC VSC can be used in the same way to connect offshore wind farms and Concentrated Solar Power from desert areas. A March 2013 report from the Friends of the Supergrid (FOSG) compares HVAC with FACTS and HVDC. See figure 53. HVDC will be competitive for longer distances with a typical break even of 600 km for a 1000 MW link.

![Figure 53: Comparison between HVAC and FACTS](image)

![Figure 54: Comparison between HVDC and HVAC (FOSG)](image)

The above figure shows a comparison of Towers at the same transmission capacity of 3000 MW for; a) 800 kV AC Line. b) 500 kV DC Line. To achieve the same level of redundancy as in case of the bipolar DC transmission, two parallel AC lines would be needed doubling the transmission corridor.

![Figure 55: Conversion of a 400 kV double AC line to 500 kV HVDC](image)

As repeatedly concluded, existing transmission grids need to be strengthened for several reasons. However, it is difficult to build new transmission lines. Here the conversion of existing HVAC OHL offers a rapid and cost efficient possibility. The main question is why it has not been used before? Once again, the answer is the lack of a strong driver. Now we have this. The AC/DC conversion technology is ready to be demonstrated and deployed. It will require studies for each application and there are different alternatives including hybrid AC and DC solutions. This is at present studied by CIGRE WG B2.41 in a “Guide to the conversion of existing AC lines to DC operation”, to be published during 2013.
FIG 56. Improvement by conversion of a 400 kV double AC line to 500 kV HVDC (ABB)

It is possible to increase the power transfer on an existing double circuit 400 kV transmission line with 2 x 3 conductors to a 500 kV triple bi-pole with 3 x 2 conductors by as much as 2-3 times. In addition to increased power transfer capability, the flexibility and redundancy will be enhanced significantly. Power Electronics gives the “Digital Power System” increased flexibility and controllability. The deployment of HVDC and especially HVDC VSC for old and new applications will provide the base for the Smart and Strong Power System. HVDC will not replace HVAC as the main carrier of electricity but we will see more hybrid systems.

FIG 57. HVDC applications

The new HVDC VSC technology offers flexible solutions as “embedded” links to control both active and reactive power within a HVAC system. The South West link in Sweden is such an example and is planned for three terminals with double HVDC links. Finally DC Grid systems are being discussed more often as a feasible solution for an overlaying “Super Grid” and for an offshore grid to interconnect offshore wind farms with HVDC links. This is not a new vision but was discussed already during the 1990s.
China is already creating a Super Grid based on HVDC which is integrated with the HVAC grid. At present, a number of HVDC VSC projects are processed for wind farms and interconnectors by the North Sea and Baltic Sea countries. The EUMENA DESERTEC is a feasible way to integrate “sun from Sahara”. ABB’s 1992 vision (to the left above) and Siemens’ vision (below) are now close to reality. More of our appliances such as computers and servers but also generation from PV is using DC. Transmission of power is using HVDC “Classic” and UHVDC. But as figure 59 illustrates we will also see more DC used in between. The rapid development of power electronics such as FACTS, STATCOM and HVDC VSC gives new tools to design and operate power systems. This will however require cooperation between all stakeholders within this power system for an optimized deployment.
TO PREDICT THE FUTURE YOU HAVE TO CREATE IT!

There is near-consensus on the challenges we face regarding energy and the environment. There is also near-consensus that we have technology available to implement the necessary actions. Still, the development of these technologies and actions to address these challenges seem to be progressing too slowly relative to the several scenarios and roadmaps telling us the consequences of our actions and none-actions. This has been very well formulated by IEA in Energy Technology Perspectives 2012. The following quote is from the foreword to the ETP 2012 by Maria van der Hoeven, Executive Director of IEA:

“Let me be straight: our ongoing failure to realise the full potential of clean energy technology is alarming. Midway through 2012, energy demand and prices are rising steadily, energy security concerns are at the forefront of the political agenda, and energy-related carbon dioxide (CO2) emissions have reached historic highs. Under current policies, both energy demand and emissions are likely to double by 2050…… The good news is that technology, together with changed behavior, offers the prospect of reaching the international goal of limiting the long-term increase of the global mean temperature to 2°C…. Knowing what we do about the link between GHG emissions and climate change, it is disturbing to see that investments in fossil-fuel technologies continue to outpace investments in best available clean energy technologies…… Too little is currently being spent on every element of the clean energy transformation pathway. As a result, clean energy technology infrastructure is being rolled out too slowly.”

Decarbonisation of energy will require increased electrification where EU, in different scenarios, looks at an increase from today’s 20% to almost 40% by 2050. A strong and smart electrical infrastructure is needed to meet energy and climate goals. Capacity, efficiency and interoperability of transmission and distribution systems for increased integration of RES and new network users, including storage and demand response, require deployment of Smart Grid technologies. Most of these technologies are already available and can be rapidly demonstrated and deployed as discussed in this paper.

There is, however, no SINGLE universal solution. We shall avoid contradiction of the “grid vs. ICT”. We cannot solve everything with new “apps” or smart meters. And we cannot solve everything by building more transmission lines. We need a strong and smart power T&D system. Here, new power electronics has a crucial role to provide both. FACTS, especially VSC-based devices for compensation at the transmission level, together with boosting the development of VSC technologies for HVDC, provides increased flexibility towards a smoother RES integration, voltage regulation and reactive power control. In the future, distribution systems with more connected DER will be more like transmission systems. D-FACTS (also known as Custom Power) and devices for distribution, like D-STATCON, can provide similar flexibility for distribution applications. These are the smart and strong “apps” we do need. The technology is available but has to be demonstrated and deployed.

One lesson from the history of the development of power technology is that it was often done in close cooperation between state owned utilities and private companies. These state owned utilities were also often vertically integrated with generation, transmission and distribution. These companies had own R&D resources and in house power system knowledge. Some countries still have this structure. Other does not where the deregulation, open market and free competition make the “old way” impossible. Since the implementation of the Smart and Strong grid requires early investments in infrastructure with a system view it is therefore of utmost importance that policy maker, regulators and governments have the framework in place to allow for and finance necessary R&D and long term investments.
5.2 Ensuring interoperability for communication and automation

The ongoing digital evolution has and is changing our way of life. Today we can communicate with our friends around the world, watch the movie we want and purchase anything we need as we walk around with our smart phone. We can store our information on a “cloud in cyberspace” and we can Google basically any information and zoom in on a picture of our own house. All this is possible because we have a reliable power grid delivering high quality electricity. All the equipment to monitor, protect and operate the power system is installed in substations and power stations. Computer based systems for SCADA, Supervisory Control and Data Acquisition has been in use since the 1970s which tap the substations for necessary information and provide possibilities to send back commands to the substation. This allows continuous supervision from a control center.

What we today call “Substation Automation”, with a digitalization of the substation, was introduced during the 1980s but a majority of the substations still have what we call an RTU, Remote Terminal Unit as the interface between the substation and the SCADA. But in many countries within “the old economies”, this essential power system is still monitored, protected and controlled with the same electro mechanical devices as fifty years ago, albeit with “islands” of digital technology. In “new economies”, with a rapid expansion of the power infrastructure, the digital technology has been and is being deployed. However, due to the continuous development of the Information and Communication Technology (ICT) these systems are rapidly ageing and require upgrading.

The advantage of the hundred + year old electromechanical technology with contacts and copper wires was and is that it is easy to mix equipment from different manufacturers and different generations. An electromechanical relay from 1929 could be connected to another electromechanical relay from 1992. But with the introduction of digital technology and communication we saw another evolution. The evolution of different protocols has made it costly and difficult to mix equipment and systems from different manufacturers. This is why IEC, as well as national standardization bodies, has and is trying to create international and open standards as a race against the evolution of technology. But this also created an “evolution” in the number of standards and different “dialects” in different countries.

During the 1980s and early 1990s a large number of digital vendor specific protection and control systems had been introduced and an increasing number of vendor specific protocols made it costly and difficult to maintain and upgrade systems. There was a need to define a common protocol and model to handle all information and communication within a digital substation. This new concept should be “future proof” allowing implementation of new technology as well as an open system, interoperable between different manufacturers. In 1994 the EPRI/IEEE started the Utility Communications Architecture (UCA) and a similar work was initiated by IEC the year after. In 1997 the groups joined forces to develop what was going to be named IEC 61850. The world’s first fully global, open and “future proof” standard to ensure interoperability for ICT applications in the power system.

The IEC 61850 standard main parts were first published from 2002 to 2005. The IEC 61850 standard initial scope was standardization of communication in substation automation systems. The first edition of the standard was primarily related to protection, control and monitoring. From 2009 and onwards, the original parts of the IEC 61850 series have been updated and extended to also cover measurement (including statistical and historical data handling) and power quality. New parts of the standard will also be added to handle condition monitoring. Given the extended scope, today's naming of the IEC 61850 standard is “Communication networks and systems for power utility automation".

71
The “digital evolution” with fast communication offers new possibilities. In all the different definitions of Smart Grids, the increased importance of ICT, Information and Communication Technology, is stressed in order to handle the increased complexity of the power system. The increase of variable generation form Renewable Energy Sources (RES) such as wind and solar requires increased flexibility and immediate adaptability. Larger disturbances have shown the need for “Visualization” and “Situational Awareness” on what is happening within a more complex power system. There is also a common understanding of the need for standardization and interoperability of the ICT “systems of systems”. This is handled globally within IEC as well as within CENELEC (EUROPE) and NIST (USA). NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 1.0 in 2010 defined 75 standards as an example. Over 100 IEC Standards have been identified as relevant to the Smart Grid. A list of the core standards is available at http://www.iec.ch/smartgrid/standards/.

For Power T&D Systems IEC 61850, together with IEC 61970 and IEC 61968, covering a Common Information Model (CIM) necessary for exchanges of data between devices and networks, primarily in the transmission (IEC 61970) and distribution (IEC 61968), domains are core standards to ensure interoperability. Particularly the IEC 61850 standard, if fully applied, will radically change how systems for monitoring, protection and control are designed, operated and maintained. It is much more than a new protocol. It is a model with a common language on how to handle the communication of information in real time. It will change the work processes. This has to be fully understood by the main users (TSOs and DSOs) so the migration from present electromechanical and/or digital technologies are planned with involvement from all relevant parts of their own organizations as well as outsourced activities. If the full benefits of IEC 61850 standard, such as the “future proof” interoperability and standardized documentation, should be harvested, there has to be enough knowhow on both ICT and Power T&D applications. The preparation, training and motivation of involved personnel is essential for the success.

ENSTO-E and The Very Large Power Grid Operator Association, GO 15 published statements regarding this standardization work in beginning of 2012. “ENTSO-E calls for all IEC61850 stakeholders to take the appropriate actions in order to ensure the success of IEC61850 and to make sure the standard – and the technologies developed around it – remain sustainable and provide significant benefits for all stakeholders and the community. This statement addresses the main stakeholders involved in the development and product implementation of the IEC61850 standard on communication networks and systems for power utility automation: secondary systems suppliers, International Electro technical Commission (IEC TC57, WG10 and others), conformance testing companies, third-party tool developers. This standard is of potentially large benefit to electricity transmission system operators (TSOs) as it addresses across different vendors many crucial aspects of TSO communications, with the promise of seamless interoperability of different vendors' subsystems within the overall TSO system management architecture.”

A similar statement came from VLPGO which now is called GO 15: “The IEC61850 standard is of potentially large benefit to Power Grid Operators (PGOs) as it addresses across different vendors many crucial aspects of PGO communications, with the promise of seamless interoperability of different vendors’ subsystems within the overall PGO system management architecture.” This was further stressed by a statement in November 2012 from GO 15: “We support the promotion of the worldwide harmonization of standards, which will provide for interoperability of the solutions in a reliable and efficient way.”

The above statements have helped to put focus on necessary work to be done. ENSTO-E is reporting this on https://www.entsoe.eu/about-entso-e/working-committees/research-and-development/standardisation/ Please see this for complete information.
Here are some highlights on what has been happening since the statement was published:

- Acknowledgment of the ENTSO-E statement by the IEC and creation of a “Users feedback” Taskforce within the IEC TC57 WG10;
- Creation within Cigré of a new working group within the SC B5 (Protection & automation section): B5.50 “IEC 61850 Based Substation Automation Systems – Users Expectations and Stakeholders Interactions”;

ENSTO-E is besides internal work also establishing liaisons with other stakeholders such as IEEE, in particular through the P2030.100 project, “Recommended Practice for Implementing an IEC 61850 Based Substation Communications, Protection, Monitoring and Control System” and with UCA, [http://www.ucaiug.org/aboutUCAIug/default.aspx](http://www.ucaiug.org/aboutUCAIug/default.aspx) in order to define a test of user cases, to demonstrate interoperability at different levels, and in particular at the level of tools.

The main concerns are lack of interoperability in multivendor solutions as well as lack of third party tools. In addition, “lack of knowledge and experience and a need for work force training and education” has been identified as important concerns. Once again, the basic feature of IEC 61850 is interoperability and the standard included from the beginning a requirement for independent testing of products to verify the conformance with the new standard.

The first products were tested by KEMA 2001 for ABB and Siemens, who also cooperated in the first multi-vendor project in Switzerland. There have been public interoperability demonstrations involving several manufacturers and there are a number of installations with several vendors in different countries. ABB has invested in a system verification center that can test the interoperability of a large number of IEDs and different vendors. STRI and other independent laboratories can provide interoperability testing. However, interoperability testing procedures need further development along with independent third party tools which can also be used for field testing. The above concerns are now being addressed within IEC and others as described above.

But there are many challenges to overcome. IEC is now accepted as the standard in most countries. Because the Smart Grid is evolving from the existing power grid, NIST has also included defacto standards that support widely deployed legacy systems in North America. Priority Action Plans (PAP) have been established to resolve interoperability issues between the standards for legacy equipment and other standards identified for the Smart Grid. For example, PAP1282 enables implementation of the Distributed Network Protocol, DNP3. The SGIP (Smart Grid Interoperability Panel) membership voted to include the IEC 61850 Standard Series into the Catalog of Standards (CoS) May 4, 2012. The standard 60870 TASE.2 was approved September 5, 2012.

The CEN-CENELEC-ETSI Smart Grid Coordination Group presented in December 2012 a first set of standards for Smart Grids which is a long list of many important standards in order to achieve a total wide area system indicated in the previous figure. The IEC 61850 covers the first process and station levels and standardizes how different types of information are communicated. Garbage-In-Garbage-Out (GIGO) is a well know expression. The voltages, currents and signals collected from the system will be used in the higher levels and has to be rapidly and accurately communicated. IEC 61850 provides integration of digital interfaces from the high voltage switchyard, communication between substations and provides remote control centers with wide area information, i.e. with a high speed Power System Internet capability. One of the main concerns is the Cyber Security. This is not covered here but by another ISGAN Discussion Papers.
FIG. 60 A Wide Area Vision of the Smart Grid


The change for information and communication will be similar to the change in the power system. Instead of have power and information flowing linear point-to-point there is a need to share information in many other ways. There is still a need to have essential functions like protection handled independently within each substation. There is additional need to have automation for fast response within each substation. Digital technology and fiber optics can integrate sensors and actuators in the switchyard and provide accurate data throughout this digital system. Wide Area Systems, e.g. WAMPAC, as discussed in 4.3 will add observability and controllability to conventional SCADA. The IEC 61850 standard has the potential to be a fundamental base for the development of the T&D part of the Smart Grid, formulating the structure, language and models to be used and affecting the complete process of engineering, operation and maintenance. For this reason, it is important for all stake holders to work within the framework of this global standard with a longer perspective and a system view. We have today a global Internet and global phone system. We communicate with smart phones, Skype and Facebook. So this should not be a technical problem to solve as such even though it is imposing even higher requirements on speed and security.

When it comes to the even bigger picture, integrating new stake holders for the commercial arena, this will require other types of functionality. We can compare this Smart Grid to a “MMORPG”, a Massive Multiplayer Online role Playing Game, which our children already are playing. For this we need clearly defined roles, rules and tools. This will be presented in an additional discussion paper from ISGAN during 2013.
It is our vision that Phasor Measurement Units (PMUs) will be installed in all major transmission level substations within the next one to two decades. This is crucial for the development and use of Wide Area Monitoring, Protection and Control Systems (WAMPACs).

To fully utilize the potential information that becomes available by phasor measurements, new applications for on-line and off-line analysis need to be developed, along with closed loop control applications. The common objective for all these applications is to enhance observability and controllability to manage the variability and dynamics of the future power system systems.

Monitoring applications (WAMS) are now maturing through many good prototype and demonstration tools. WAMS applications are also seen to be integrated with the traditional SCADA/EMS solutions. This development has to continue. All the operational tools and applications must be integrated in order to release the full potential of WAMS. Only in this way will the operators gain experience with using the applications and thus be able to acknowledge the added information provided by WAMS.

Research and development must continue, in particular on the development of robust protection and control solutions. There are great possibilities in combining wide area measurements, communication and coordinated control to develop Smart Grid applications that will maintain the security and integrity of the future power system. This development is only limited by our imagination and ability to best use all available information.

An integrated part of the research challenge will thus also be to manage the cyber security aspects which are brought forward by the dependence on information and communication technologies. There are still many open questions with regards to the design of fast, reliable and secure ICT systems, including how to manage and make useful information out of the enormous amounts of data that will become available.
## 6 List of HVDC VSC projects

<table>
<thead>
<tr>
<th>Name</th>
<th>Country</th>
<th>Cable (km)</th>
<th>OHL (km)</th>
<th>Volt (kV)</th>
<th>Power (MW)</th>
<th>Year</th>
<th>Supplier</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hellsjön-Grängesberg</td>
<td>Sweden</td>
<td>0,2</td>
<td>10</td>
<td>±10</td>
<td>3</td>
<td>1997</td>
<td>ABB. The first HVDC VSC pilot system in the world</td>
</tr>
<tr>
<td>Gotland Visby-Nas</td>
<td>Sweden</td>
<td>70</td>
<td>±80</td>
<td>70</td>
<td>1999</td>
<td>ABB.</td>
<td>The first HVDC VSC commercial system in the world</td>
</tr>
<tr>
<td>Terranora (Directlink)</td>
<td>Australia</td>
<td>65</td>
<td>±80</td>
<td>180</td>
<td>2000</td>
<td>ABB.</td>
<td>Land cable</td>
</tr>
<tr>
<td>Eagle Pass, Texas B2B</td>
<td>USA</td>
<td></td>
<td></td>
<td>±16</td>
<td>36</td>
<td>2000</td>
<td>ABB.</td>
</tr>
<tr>
<td>Tjæreborg</td>
<td>Denmark</td>
<td>4,4</td>
<td>±9</td>
<td>7</td>
<td>2000</td>
<td>ABB.</td>
<td>Interconnection to wind power generating stations</td>
</tr>
<tr>
<td>Cross Sound Cable</td>
<td>USA</td>
<td>40</td>
<td>±150</td>
<td>330</td>
<td>2002</td>
<td>ABB.</td>
<td>Buried underwater cable</td>
</tr>
<tr>
<td>Murraylink</td>
<td>Australia</td>
<td>180</td>
<td>±150</td>
<td>220</td>
<td>2002</td>
<td>ABB.</td>
<td>Underground XLPE cable</td>
</tr>
<tr>
<td>HVDC Troll 1-2</td>
<td>Norway</td>
<td>67</td>
<td>±60</td>
<td>2x41</td>
<td>2005</td>
<td>ABB.</td>
<td>The world’s first offshore platform HVDC transmission.</td>
</tr>
<tr>
<td>Estlink</td>
<td>Estonia - Finland</td>
<td>105</td>
<td>±150</td>
<td>350</td>
<td>2006</td>
<td>ABB.</td>
<td></td>
</tr>
<tr>
<td>BORWIN 1</td>
<td>Germany</td>
<td>203</td>
<td>±150</td>
<td>400</td>
<td>2009</td>
<td>ABB.</td>
<td></td>
</tr>
<tr>
<td>Valhall</td>
<td>Norway</td>
<td>292</td>
<td></td>
<td>150</td>
<td>78</td>
<td>2010</td>
<td>ABB.</td>
</tr>
<tr>
<td>Trans Bay Cable</td>
<td>USA</td>
<td>85</td>
<td>±200</td>
<td>400</td>
<td>2010</td>
<td>Siemens &amp; Pirelli; This was Siemens first VSC installation.</td>
<td></td>
</tr>
<tr>
<td>Caprivi Link</td>
<td>Namibia</td>
<td>950</td>
<td>350</td>
<td>300</td>
<td>2010</td>
<td>ABB.</td>
<td>The first commercial HVDC VSC OHL</td>
</tr>
<tr>
<td>East West Interconnector</td>
<td>Ireland - UK</td>
<td>250</td>
<td>±1200</td>
<td>500</td>
<td>2012</td>
<td>ABB.</td>
<td></td>
</tr>
<tr>
<td>BorWin2</td>
<td>Germany</td>
<td>200</td>
<td>±1300</td>
<td>800</td>
<td>2013</td>
<td>Siemens.</td>
<td></td>
</tr>
<tr>
<td>DolWin1</td>
<td>Germany</td>
<td>165</td>
<td>±1320</td>
<td>800</td>
<td>2013</td>
<td>ABB.</td>
<td></td>
</tr>
<tr>
<td>HelWin1</td>
<td>Germany</td>
<td>130</td>
<td>±1250</td>
<td>576</td>
<td>2013</td>
<td>Siemens.</td>
<td></td>
</tr>
<tr>
<td>Dalian City Infeed</td>
<td>China</td>
<td>43</td>
<td>±1320</td>
<td>1000</td>
<td>2013</td>
<td>CEPRI</td>
<td></td>
</tr>
<tr>
<td>SyiWin1</td>
<td>Germany</td>
<td>205</td>
<td>±1320</td>
<td>864</td>
<td>2014</td>
<td>Siemens.</td>
<td></td>
</tr>
<tr>
<td>Skagerak 4</td>
<td>Norway - Denmark</td>
<td>240</td>
<td>500</td>
<td>700</td>
<td>2014</td>
<td>ABB. The first 500 kV IGBT (integrated with existing Thyristors)</td>
<td></td>
</tr>
<tr>
<td>Mackinac B2B</td>
<td>USA</td>
<td></td>
<td>±71</td>
<td>200</td>
<td>2014</td>
<td>ABB.</td>
<td></td>
</tr>
<tr>
<td>SydVästlänken</td>
<td>Sweden</td>
<td>200</td>
<td>±300</td>
<td>2x720</td>
<td>2014</td>
<td>Alstom Grid (VSC), ABB (Cable)</td>
<td></td>
</tr>
<tr>
<td>INELFE France - Spain</td>
<td>France - Baixas</td>
<td>60</td>
<td>±320</td>
<td>2x1000</td>
<td>2014</td>
<td>Siemens</td>
<td></td>
</tr>
<tr>
<td>Troll &amp;4</td>
<td>Norway</td>
<td>67</td>
<td>±60</td>
<td>2x50</td>
<td>2015</td>
<td>ABB.</td>
<td></td>
</tr>
<tr>
<td>DolWin2</td>
<td>Germany</td>
<td>135</td>
<td>±1320</td>
<td>900</td>
<td>2015</td>
<td>ABB.</td>
<td></td>
</tr>
<tr>
<td>NordBalt</td>
<td>Sweden - Lithuania</td>
<td>450</td>
<td>±300</td>
<td>700</td>
<td>2015</td>
<td>ABB.</td>
<td></td>
</tr>
<tr>
<td>Åland</td>
<td>Finland-Åland</td>
<td>150</td>
<td>±80</td>
<td>100</td>
<td>2015</td>
<td>ABB.</td>
<td></td>
</tr>
<tr>
<td>HelWin2</td>
<td>Germany</td>
<td>130</td>
<td>±1320</td>
<td>690</td>
<td>2015</td>
<td>Siemens.</td>
<td></td>
</tr>
<tr>
<td>Zhoushan Multi-terminal</td>
<td>China</td>
<td>134</td>
<td>±200</td>
<td>400?</td>
<td>2017</td>
<td>CEPI 400/300/100/100/100</td>
<td></td>
</tr>
<tr>
<td>DolWin3</td>
<td>Germany</td>
<td>162</td>
<td>±320</td>
<td>900</td>
<td>2017</td>
<td>Alstom Grid</td>
<td></td>
</tr>
</tbody>
</table>
7 References

The information used in this Discussion Paper is derived from the work within “IEA Implementing Agreement on Electricity Networks Analysis, Research & Development (ENARD) Annex IV on Transmission Systems and the work within IEA Implementing Agreement on International Smart Grid Action Network (ISAGN) Annex 6 on Power Transmission and Distribution Systems. This work is documented in the following reports:


References from external publications:

- NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 1.0 and 2.0
- CEN-CENELEC-ETSI Smart Grid Coordination Group Smart Grid Reference Architecture, Nov 2012
- CEN-CENELEC-ETSI Smart Grid Coordination Group Smart Grid Reference Architecture, Nov 2012
- CEN-CENELEC-ETSI Smart Grid Coordination Group First Set of Standards, Nov 2012ABB documentation including latest edition of “It’s time to connect” and published information about HVDC VSC projects.
- STRI studies for Svenska Kraftnät and Statnett on HVDC VSC multi terminal applications. (4 reports during 2008-2011)
- EWEA publications and Offshore Grid study published by 3E in October 2012
- Nordic Grid Development Plan 2012
- BP Statistical Review of World Energy 2012
- CIGRE report 269 VSC Transmission April 2005
- CIGRE report 370 Integration f Large Scale Wind Generation Using HVDC and Power Electronics, February 2009
• CIGRE report 447 Components Testing of VSC System for HVDC Applications, February 2011
• CIGRE report 492 Voltage Source Converter (VSC) HVDC for Power Transmission – Economic Aspects and Comparison with other AC and DC Technologies, April 2012
• Ongoing CIGRE work including “HVDC Grid Feasibility Study” to be published Q2 2013.
• ENSTO-E Ten-Year Network Development Plan 2012
• ENSTO-E Offshore Transmission Technology 24.11.2011
• ENTSO-E statement on the IEC61850 standard Brussels, 2012-04-13
• The German DKE initiative on “Technical Guidelines for first HVDC grids, Sept. 2012 which has been reissued by CENELEC in November 2012.
• Relevant IEA publications including ETP 2012 and WEO 2012
• U.S. DOE Electricity Transmission System Workshop, Nov. 2012
• Other relevant information from Carbon Trust, National Grid, ISLES study, Kriegers Flak, EWEA offshore wind conference, International Workshop on Large-Scale Integration of Wind Power & Transmission Networks for Offshore Wind Power, IEEE, ELFORSK, ISGAN reports and other conference papers
• Ongoing work within Joint Industry Initiative on HVDC offshore transmission.
• The main information regarding IEC 61850 and other related references are obtained from IEC TC 57, http://tc57.iec.ch/index-tc57.html and UCA user group http://www.ucaiug.org/default.aspx
• The work on “COMMUNICATION NETWORKS AND SYSTEMS FOR POWER UTILITY AUTOMATION” is now for all major parts published or as the 2.0 version of the standard suite.
• In addition, continuous updates by Karlheinz Schwarz starting with Praxis Profiline and ongoing through News on IEC 61850 and related Standards, http://blog.iec61850.com/, PAC World Alex Apostolov/ Christoph Brunner, http://www.pacw.org and the work within IEC TC 57 WG 10 as reported by Nicholas Etherden, STRI on behalf of Svenska Kraftnät.
• The implementation of PMU for Wide Area Measurement Systems (WAMS) is also based on the experience of U.S. DoE through Philip Overholt, who is program manager for the U.S. deployment of PMU/WAMS, and SINTEF/NTNU through Kjetil Uhlen, who is leading R&D efforts in this area. North American SynchroPhasor Initiative, NASPI is updated in https://www.naspi.org/
Acronyms and abbreviations used in this report have the following meaning:

AC, Alternating Current
AIS, Air Isolated Switchgear (open-field surface substation, as opposed to GIS)
AMI, Advanced Metering Infrastructure
AR, Auto reclosing is used to restore operation of a power line when a fault has been cleared.
BAT, Battery storage
BCU, Bay Control Unit
BPU, Bay Protection Unit
CID, Configured IED Description
CIM, Common Information Model
CIM, Common Information Model
CPU, Central Processing Unit
CT, Current Transformer
DC, Direct Current
DCB, Disconnecting Circuit Breaker
DER, Distributed Energy Resources
DMS, Distribution Management System
DOCT, Digital Optical Current Transformer
DOIT, Digital Optical Instrument Transformer
DOVT, Digital Optical Voltage Transformer
DSM, Demand Side Management
DSO, Distribution System Operator
EDI, Electronic Data Interchange
EIPP, Eastern Interconnection Phasor Project
EMC, Electro Magnetic Compatibility
EMI, Electro-Magnetic Interference
EMS, Energy Management System
EMTP, Electromagnetic transients program
ENSTO-E, European Network of Transmission System Operators
EV, Electrical Vehicles
FACTS, Flexible AC Transmission Systems
FAT, Factory Acceptance Test
FB, Full Bridge
FERC, Federal Energy Regulatory Commission
FLM, Flexible Line Management utilizing dynamic rating of transmission lines
FOCT, Fibre Optic Current Transformer
FOSG, Friends of the Super Grid
FTP, File Transfer Protocol [RFC 959]
GIS, Gas Isolated Switchgear
GOOSE, Generic Object Oriented Substation Events
GPS, Global Positioning System
GW, gigawatt (1 Watt x 10^9)
HAN, Home Automation Network
HB, Half Bridge
HMI, Human Machine Interface
HSS, High Speed Switch
HVAC, High Voltage Alternating Current
HVDC CSC, Current Source Converter also called “Classic” using thyristors
HVDC High Voltage Direct Current
HVDC LCC, HVDC Line Communicating Converters also called HVDC-CSC
HVDC VSC, HVDC Voltage Source Converters using transistors (IGBT)
ICD, IED Capability Description
ICMP, Internet Control Message Protocol [RFC 792]
ICT, Information and Communication Technology
IEC, International Electrotechnical Commission
IED, Intelligent Electronic Device
IGBT, Insulated Gate Bipolar Transistor
IP, Internet Protocol [RFC 791]
IRIG-B, Inter-Range Instrumentation Group time code B
kW, kilowatt (1 Watt x 10^3)
LAN, Local Area Network
LCC, Line Commutated Converter
MMC, Modular Multilevel Converter
MMS, Manufacturing Message Specification
MSTP, Multiple Spanning Tree Protocol [IEEE 802.1Q-2011]
MTBR, Mean Time Between Repairs
MTTF, Mean Time To Fail
MTTR, Mean Time To Repair or Mean Time To Recovery
MU, Merging Unit
MW, megawatt (1 Watt x 10^6)
NASPI, North American Synchrophasor Initiative
NCCIT, Non-Conventional Instrument Transformers
NERC, North American Electric Reliability Council
NIS, Network Information System
NIST, U.S. National Institute of Standards and Technology
OHL, Overhead transmission line
PAC, Protection and Control
PCC AC, Point of common coupling (ac side)
PCC DC, Point of common coupling (dc side)
PGO, Power Grid Operator
PLC, Power Line Carrier is used to send information with higher frequency on a power line.
PMC, Protection, Measurement and Control combined IED
PMU, Phasor Measurement Units
POC, Proof of Concept
POD, Power Oscillation Damping
POM, Power Oscillation Monitoring
RAS, Remedial Action Scheme
RAS, Remedial Action Scheme also called SPS (See below)
RES, Renewable Energy Sources
RSTP, Rapid Spanning Tree Protocol [IEEE 802.1D]
RTU, Remote Terminal Units
SAMU, Stand-Alone Merging Unit [IEC 61869-9]
SCADA, Supervisory Control and Data Acquisition
SCD, Substation Configuration Description [IEC 61850-6]
SCED, security constrained economic dispatch
SCL, Substation Configuration Language [IEC 61850-6]
SCUC, security constrained unit commitment
SGAM, Smart Grid Architecture Model
SGIP, Smart Grid Interoperability Panel
SPS, System Integrity Protection Schemes
SPS, Special Protection Scheme also called System Protection Schemes or RAS
SSD, System Specification Description
SV, Sampled (measurement) values [IEC 61850-9-2]
SVC, Static VAR Compensation
TCSC, Thyristor Controlled Series Compensation
TRV, Transient Recovery Voltage
TSO, Transmission System Operator
TW, terawatt (1 Watt x 10^{12})
UCA, Utility Communications Architecture
W, watt (1 joule per second)
WAM, Wide Area Monitoring
WAMPAC, Wide Area Monitoring, Protection and Control
WAN, Wide Area Network
WAP, Wide Area Protection
WASAS, Wide Area Situational Awareness System
WCB, Withdrawable Circuit Breaker
WECC, Western Electric Coordinating Council
VAL, Variable Load
VLAN, Virtual Local Area Network [IEEE 802.1Q]
VPP, Virtual Power Plant is the clustering of generation from DER
VT, Voltage Transformer