Abstract—Electricity networks operators must operate their network with a high degree of efficiency and reliability. Presently the drivers for lower-carbon electricity generation technologies are high, and to accommodate such technologies (e.g. large-scale wind power), significant changes have to be made to the way that Transmission and Distribution (T&D) networks are designed and operated. The Smart Grid concept has been introduced to highlight alternative, automated technologies that may bring significant benefits to the T&D networks. This paper summarizes smart grid technologies within the T&D sector that in terms of technology readiness are superior to other technologies, and are expected to be deployed in the near future. This paper summarizes the drivers behind development of the smart grid, then by introducing some smart grid technologies, their potential applications and benefits are discussed. The engineering challenges which may prevent large scale deployment of smart grid technologies is discussed

Index Terms—Smart Grid, Demand Response, Smart Meter, PMU, FACTS, SVC, STATCOM, Active Thermal Monitoring, Electric Vehicle, Energy Storage.

I. INTRODUCTION

In 21st century, the drive towards decarbonisation of the electricity industry will have a material impact on the use of both transmission and distribution networks and the technologies applied to them. A major challenge for power utilities is to align their individual decisions with the ultimate goal of the electricity industry. Decisions on how to operate the network, what assets to be used, maintenance schedules, and customer service are all likely to change. These changes are driven by [1]:

- Recognition that the existing networks are reaching the limits of efficiency gains deliverable through existing assets and traditional technologies; and
- Recognition that the industry is moving from a hierarchical and top-down power flow environment, into a system in which bidirectional power flow is expected due to the connection of generators at multiple locations, given the transition to a low carbon economy.

Most utilities are currently undertaking research and development to set the future directions of their network operation.

A. Climate Change and Renewable Power Generation

The electricity industry is moving from conventional fossil fuel burnt generation towards alternative low carbon generation. Technologies that can contribute to achieving this target include renewables and small scale non-renewable power generators located close to load centres; known as distributed generation (DG). The consequences of increasing the penetration of such generation technologies embedded into the system include [2]:

- Reserve Power Flow: DGs can supply the local demand and reduce the need for power transport from high voltage transmission to low voltage distribution systems, in turn reducing the power losses. This reduction in power losses is mainly due to supplying the load locally at LV level. Large scale connection of DGs will reverse power flow across the network.
- Network Congestion: The location of large-scale renewable generation technologies is determined by the availability of the energy source; e.g. locations with a higher average wind speed are chosen for windfarms. In general, windfarms or generators 60 MVA or less connect to 11 kV or 33 kV distribution networks, and above 60 MVA they are mostly connected to transmission networks at higher voltage levels. The existing T&D networks were not originally designed to accommodate localized generation. Consequently, in many regions the T&D network operators are expecting an increase of network congestion particularly in remote and rural areas. In distribution networks; the issue of voltage rise (if embedded generation is installed at a remote and weak point in the network) and increased fault current (if embedded generation is installed close to the load centres; such as micro-CHP) will be the result. In transmission networks, transferring a high volume of energy from renewable generation zones to the load centres may cause transmission bottlenecks across the networks and result in curtailing the power output of the renewable generators.
- Less Controllability of Renewable Generation: There is limited control over a renewable generators’ output compared with conventional plants. The conventional power dispatch methods may not satisfy the fact that intermittent generation such as wind power, may not be able to deliver their expected power output.

B. Meeting the Reliability Criteria

The reliability of their electricity supply infrastructure is the one of the ultimate goals of all utilities. The consequence
of not achieving reliability targets set by local reliability councils could result in a significant loss of revenue. To achieve the required reliability criteria, each utility has to spend some of its revenue to take measures to comply with regulations and standards. This may even have impact on how efficiently they may be to able to operate their network.

C. Ageing the Assets

Network reinforcement may be required due to increased level of demand supplied by the network or increased number of power plants delivering power through the network. Additionally, upgrading network components usually happens when the current assets are no longer able to function as they should, and the maintenance cost is so high that replacing the asset with new equipment may be more feasible. The existing assets within T&D networks in most countries were installed in 1960s. There are two main issues with regard to the old assets [3]:

- The existing assets were designed to provide resilience in case of the breakdown of large power plants. The top-down, unidirectional power flow in systems provide sufficient transmission access to large power plants installed far from load centres. Such old assets may not provide access to localized power plants and permit bidirectional power flow in the system.
- The replacement of old- with new-assets employing state of the art technology may result in an adaptation problem for the new assets and their capability to function along with remaining, older assets. Therefore, it may be necessary to change additional equipment(s) to enable the integration of the new assets.

D. Need for Wider Participation

The T&D networks are in fact monopoly companies within their area of their business, although the whole market is privatised. In most privatised electricity markets, there is a very limited capability of wider participation for better management and operation of the network. In particular, consumer participation in active demand management is limited to large consumers. Small domestic households may only be able to participate through passive demand management schemes, e.g. shifting the demand from peak to off-peak periods. To improve competition it is necessary to facilitate the participation of all consumers. This is in turn beneficial for both utilities and consumers. Incentives can be paid to the consumers for their participation, and utilities benefit by being able to have a more flexible approach to network operation and management.

II. DEFINITION OF SMART GRID

The “smart grid” is an umbrella term for a range of technologies which have been developed as an alternative to traditional methods for network operation. The smart grid can allow greater competition between providers, enabling greater use of intermittent power resources, establishing the wide area automation and monitoring capabilities needed for both bulk transmission over wide distances and distributed power generation, enabling more efficient outage management, streamline back office operations, enabling the use of market forces to drive retail demand response and energy conservation. The smart grid technologies will bring the following benefits to T&D networks:

A. Reliability

Through using intelligent and state of the art technologies that enable real time communication and exchange of data between generation, transmission and distribution, and consumers. This may remove the need for human interference in making the decisions to protect the system, and, the likelihood of system failure (blackout) as a result of sudden changes in the system characteristics will be minimized.

B. Flexibility

The flexibility in operation of the T&D networks allows network operator to better do business. Different demand side management technologies and various forms of generation can all be provided by smart grid technologies. This will diversify the operation options that can help achieve the reliability, environmental and economic targets.

C. Efficiency

The power transmission sector among all other electricity sectors is designed and operated with high level of efficiency. As a result, the total energy loss across the transmission networks is usually below 2% of the total losses. The efficiency of distribution networks is lower. This is also the case for the generation sector in which some power plants may be forced to operate at lower efficiency levels due to operational constraints. On the other hand, the efficient integration of distributed generators is unlikely to be made without changes to transmission and distribution network structure, planning and operating procedures. It anticipated that there will be less of a distinction between network types, and future distribution networks may become more active and share many of the responsibilities of existing transmission systems. Active networks are in fact distribution networks with some form of distributed energy resources (generators, energy storage) and flexible loads subject to control. Such networks and participating loads take some degree of responsibility for system support, which will depend on a suitable regulatory environment and connection agreements.

D. Environmentally-Friendly Network Operation

Most network operators have an obligatory duty to minimize the negative impact of their actions on the environment; i.e. reducing their carbon foot-print. This is a very broad topic within the T&D industry and it covers many aspects such as reducing call-outs and vehicle usage, to minimizing the SF6 leakage in gas-insulated substations. What smart grid technologies can provide to reduce the carbon footprint of the T&D industry is a fast and automated service. For instance, automated meter reading in contrast to meter reader staff visiting the customers’ premises, and automated outage management in contrast with technicians visiting substations to reconfigure the network.
III. SMART GRID TECHNOLOGIES

A. Active Network Management Modules

To allow the utilization of new forms of energy generation and consumption, T&D networks must move from a single passive and centrally controlled grid to active and automated sub-networks. Such a transition will enable the network operators to achieve higher degrees of efficiency and reliability by automation in system control. It will also permit the connection of various types of distributed generation by enabling the network to monitor and control their power outputs. Additionally, the efficiency and reliability will be enhanced by wider participation in operation and management of the network by enabling the consumers to participate in such activities.

1.1. Smart Demand Side Management

1.1.1. Smart Metering

The smart meter will provide the means of communication between consumers and the utilities. This will enable the integration of other technologies such as demand response. Real-time consumption level data can be transferred to the utilities, and will enable the consumers to monitor their electricity consumption and take measures to reduce their usage. Additionally, smart meters can provide real-time pricing of the electricity or indirect load control known as dynamic price response including [4]:

- **Time of Use (ToU) tariff**: This scheme encourages consumers to shift their consumption from a peak- to off-peak period. This is a non-dynamic tariff, and in fact large-scale integration of such a tariff may in turn just simply shift the peak time.

- **Real-Time Pricing (RTP)**: The price of the electricity in the market changes hourly (or half an hourly in some markets). The RTP programmes offer a type of tariff which changes hourly to reflect the variations in supply and demand and the price of the electricity in the market. It provides incentives to consumers to limit their consumption when the wholesale price of the electricity is high and increase their consumption at lower electricity price periods.

- **Coincident Peak Pricing (CPP) or known as Critical Peak Pricing (CPP)**: RTP is deemed infeasible for residential customers, a reasonable alternative is critical-peak pricing (CPP). CPP tariffs augment a time-invariant or TOU rate structure with a dispatchable high or “critical” price during periods of system stress. The critical price can occur for a limited number of discretionary days per year, or when system or market conditions meet pre-defined conditions. Participating customers receive notification of the dispatchable high price, typically a day in advance, and in some cases are provided with automated control technologies to support efficient load drop. Because all of the prices in a CPP rate are preset, CPP is not as economically efficient as RTP; this same characteristic, however, also makes CPP politically more appealing, because it diminishes the potentially large price risk associated with RTP.

Another major benefit of smart meters is detection of electricity theft which account of some of the revenue of utilities. Since the communication is happening at real-time, any tampering with the metering equipment, or bypassing the meter can be transmitted to the utility.

At present, in some European countries old electricity meters have been replaced by smart meters. In Italy there is a large distributor (ENEL) and many medium-sized distributors owned by Municipalities (Rome, Milan, Turin, Brescia, Parma, Verona, Trieste, Bologna, etc), and of smaller local distributors. An automatic (Smart) Metering scheme is mandatory for ENEL, while the rest of the distributors continue to use the old metering systems. Generally, meters are owned by distributors and customers are not allowed to buy their own meters. ENEL has managed to install nearly 27 million meters over five years from 2002, with an investment over 2.2 billion Euro. Different types of customer have been given smart meters, and as December 2006 over 95% of the electricity meters owned by ENEL were smart meters [1].

ERDF, a subsidiary of EDF, and the largest electricity distribution network in the European Union; deals with 33 million customers in France. EDF announced the first phase of a nationwide rollout of 35 million smart meters in July 2008. The consortium, led by Atos Origin, the international information technology company, will conduct a pilot project encompassing 300,000 Power Line Communication (PLC) meters and 7,000 data concentrators in France. The project roll-out is expected to start early in 2010 [3].

1.1.2. Demand Response

The present non-responsive nature of load necessitates transporting bulk power from remote power stations. High peak demand increases the loading of the T&D networks, increases the need for peak lopping power plants, and increases the wholesale cost of electricity – both drawbacks of non-responsive demand. Demand Response (DR) can enable the loads to respond to changes in the supply side. It will allow utilities to have control of loads, to optimise the power flow across the network and better utilize their T&D assets.

Demand response may be defined by changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time. It may be implemented in the system through incentive payments designed to encourage lower electricity use at times of high wholesale market prices or when system reliability is in danger. This definition only covers the economy based products of demand response. It has far more important aspects which can not be defined by such definition. In practice demand response in the electricity industry is defined as a technology that enables loads to respond to the generation, and T&D side. Demand response includes direct load control schemes like partial or curtailable load reductions, and complete load interruptions on loads such as residential air conditioners. Demand response provides a number of opportunities for improving the planning and operation of the power system. The benefits include:

- Reducing price volatility/flattening spot prices;
- Improving system security and reducing the risk of blackouts;
- Reducing network congestion;
- Delaying construction of additional generation, and/or grid and network upgrading (network reinforcement deferral);
- Reducing greenhouse gas emissions; and
- Improving market efficiency by enhancing consumers’ ability to respond to changing prices.

Demand response may be provided through installation of demand response modules on consumer appliances. The communication between the demand response module (DRM) and the system may be provided through PLC or wireless, i.e., mobile phone signals. The DRM will respond to changes of one or some objectives in the supply side (such as loading level of a branch or changes in system frequency) and will switch off a group of appliances. The module may switch on the appliances after certain period of time, or may be instructed by the system operator to do so.

Demand response in the 10 North American Independent System Operator (ISO) and Regional Transmission Operator (RTO) markets serves several critical roles in the management of the regional power grids. Almost all ISOs and RTOs offer demand response packages to eligible consumers (depending on load type and size). More than 23 GW of demand response consumers are now participating in the North American ISO and RTO markets, representing 4.5% of their combined electricity demand. Researchers have found that demand response of about 5% to 15% of peak demand results in an efficient balance between building new supply resources and reducing demand [5].

In Europe, ERDF introduced an optional tariff called “Tempo” for domestic customers with over 9 kW peak demand, with prices that vary according to the time of day and year [6]. It colour codes days according to price (blue for low, white for medium and red for high) and each evening, a customer display unit indicates the “colour” of the following day, usually linked to the weather. Customers can then reduce their consumption on the highly priced days and ERDF can reduce peak demand. (Tempo was originally devised as a load-shifting scheme.) The system allows customers to take savings made during one period as increased comfort in others without increasing their overall spend. In Italy ENELEC offers distribution networks (below 33 kV) are designed to provide restoration verification via automated modules. PECO; the electricity supplier in Philadelphia has begun the automated outage management integration initiative [11]. This project aims to investigate the ability to remotely identify customer power status, to process outage messages and to provide restoration verification via automated modules. PECO also established two specific goals. The first goal was to set a target of US$400,000 of annual operation and maintenance (O&M) savings in avoided costs from reduced overtime and outside contractor requirements through better outage event management. The second goal was to reduce the customer

The ATRM involves installation of sensors to measure the loading level of branches at the distribution level and transmitting this information to the utility. The ratings of power equipment via ATRM are typically 5% to 15% higher than conventional static ratings. The application of dynamic ratings may enhance the economical operation by enabling less constrained operation and providing timely mitigation action to avoid dangerous system insecurity conditions by tracking the thermal state of equipment. There are several practical implementation issues which must be taken into account, including SCADA/EMS flexibility and capability, communication links, instrument reliability, and general engineering acceptance regarding dynamic rating and its variability. Due to these issues, dynamic ratings are still not widely integrated into power system operations [10].

1.3) Outage Management

The security and quality of supply in T&D networks is assessed depending on various objectives; number of interruptions, duration of an interruption, and the electrical energy not supplied due to an interruption.

At present in transmission networks, there are various arrangements to protect the system against faults, and maintain uninterrupted power transfer across the network. This is necessary due to quantity of electrical energy transferred across transmission networks and the number of customers which may be affected as a result.

Distribution networks (below 33 kV) are designed to supply a number of customers from each feeder so in the case on an outage the impact on the performance of the distribution company is less severe. Generally at 33 kV level, up to 35 MVA load can be supplied from a single feeder. This level is lower for lower voltage levels and at 11 kV, and 0.4 kV level, the maximum number of individual customers which may be supplied from a single feeder must not exceed 2500, and 200 respectively. Interruption of electricity supply particularly at rural distribution level where relatively smaller number of customers may be affected may take longer to be reported and corrected; this may damage the performance of a distribution network company overall.

Smart sensors with Geographic Information System (GIS) capability can immediately transmit the nature and the location of the incident to the local maintenance team. Outage management technologies are able to restore the supply of the electricity by reconnecting the faulted line if the fault has been cleared, or change the direction of power transfer from another location so the supply of electricity will not be affected. The later may require some form of demand response so the change of the power flow direction does not cause unplanned interruption of supply in another area.

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average interruption duration index (CAIDI) by 2 to 4 minutes through improved event analysis, including nested outage recognition.

1.4) Active Fault Level Monitoring

Traditionally, equipment is rated based on the maximum possible fault level it could be exposed to. In many instances, this high level may only happen for a certain network configuration (e.g., a given substation’s switchboard when all tie-lines are closed). Active Fault Level Monitoring monitors the different locations in the network in real time, to assess the level of connected generation and overall fault level. The system may change the network topology by splitting the busbar and changing the equivalent impedance when fault levels approach maximum permitted limits.

1.5) Active Synchrophasor Monitoring (Phasor Measurement Unit)

Most monitoring activities within the grid are based on non-simultaneous average values of measurements taken over a period of many seconds. This is valuable in assessing the steady-state condition of the grid, but is not very useful in understanding quickly changing transient phenomena that can be associated with a system collapse. Monitoring of line voltage phase angles (phasors) can fill that gap, providing the instantaneous measurement of electrical magnitudes and angles that can reveal emerging instability.

B. FACTS Devices

Smart Grid solutions such as FACTS (Flexible AC Transmission Systems) devices can be used to optimize new and existing T&D networks. FACTS devices can transform the T&D network to a highly efficient and reliable system to improve the quality and the quantity of the power delivery [12]. Some of the benefits of installing a FACTS device include:

- Steady-state and dynamic reactive power compensation and voltage regulation
- Steady-state and dynamic stability enhancement
- Increasing power transfer capability of existing assets
- Reduced fault current
- Reduced transmission losses
- Improving power quality

FACTS devices have been deployed for nearly 40 years, particularly in transmission networks. The research challenges in this area lie in new devices and materials for high-current, high-voltage switching power electronics, new device configurations/systems and the control of these switching devices to optimise network operation and management. The new equipments are to be developed by lowering the cost associated with FACTS equipments so that these devices can be used cost-effectively at distribution voltage levels.

1.1) Fault Current Limiters

Fault-current limiters (FCLs) using high temperature superconductors offer a solution to controlling fault-current levels on utility distribution and transmission networks. Such fault-current limiters, unlike reactors or high-impedance transformers, will limit fault currents without adding impedance to the circuit during normal operation.

Currently the conventional FCLs known as an “Is Limiter” is widely used in industrial systems. The “Is Limiter” consists of an explosive device along with a fuse and will explode in a few milliseconds after the fault current exceeds a certain level trigger level. Due to explosive nature of the “Is Limiter” the application of these devices are limited to systems below 40.5 kV. These devices are not considered failsafe by some certifying authorities and require servicing after each operation.

Superconducting fault-current limiters (SCFCLs) can be used to increase the source impedance and limit fault currents during fault conditions only. SCFCLs increase the series impedance and limit the fault current. The application of SCFCLs are limited to some trial tests including an 8 kV, 6.4 MVA SCFCL by ABB. Further development of SCFCLs is being pursued by several utilities and electrical manufacturers around the world.

1.2) Voltage Control and var Support Devices

Shunt voltage support equipments are to control the AC voltage in transmission networks. Power electronic equipment, such as the thyristor controlled reactor (TCR) and the thyristor switched capacitor (TSC) have gained a significant market, primarily because of well-proven robustness to supply dynamic reactive power with fast response time and with low maintenance requirements.

A rapidly operating Static var Compensator (SVC) can continuously provide the reactive power required to control dynamic voltage swings under various system conditions and thereby improve the system performance. Installing an SVC at one or more suitable points in the network will increase the transfer capability through enhanced voltage stability, while maintaining a smooth voltage profile under different network conditions. In addition, an SVC can mitigate active power oscillations through voltage amplitude modulation.

Similar to the SVC the Static Synchronous Compensator (STATCOM) can provide instantaneous and continuously variable reactive power in response to grid voltage transients, enhancing the grid voltage stability. However, the key difference between them is the dependency of their reactive power output to the magnitude of the voltage. The total reactive power of a SVC changes depending on the voltage level at the SVC’s terminals. Hence, the rating of a SVC is the maximum reactive power which the SVC can supply at the nominal system voltage. The STATCOM operates according to voltage source principles, which together with PWM (Pulsed Width Modulation) switching of IGBTs (Insulated Gate Bipolar Transistors) gives it unequalled performance in terms of effective rating and response speed. Therefore, the maximum reactive power of a STATCOM is not affected by the magnitude of the voltage at the STATCOM’s terminals. Both SVCs and STATCOMs are very expensive equipments and their present application is generally limited to transmission networks, and only for reactive power management particularly required for Grid Code Compliance.

Several new technologies such as distribution static var compensators (D-SVC), and distribution static synchronous compensator (D-STATCOM) are under investigation which connect directly to medium voltage distribution networks without the need for step-up transformer. At present, there is a tendency in new designs to employ these equipments at distribution levels for voltage quality improvement because of
their advantages and continuous lowering of installation costs due to reduced cost of power semiconductor switches.

1.3) Increasing the Grid’s Capacity through Controlling the Network Impedance

The Unified Power Flow Controller (UPFC) can be used to control the active and reactive power flow of a transmission line and bus voltage independently. The controller is capable of regulating the voltage magnitude and angles of the sending and receiving end voltages, thus controlling the power flow in the transmission line, and selectively changing the transmission line impedance; the control scheme is designed in a way that these parameters can be controlled concurrently or selectively. This will increase the power transferability on the transmission network and reduces the need for network reinforcement.

American Electric Power (AEP) has commissioned the Inez Substation in eastern Kentucky for the location of the world’s first Unified Power Flow Controller (UPFC) installation. Comprising two ±160 MVA voltage-sourced GTO-thyristor-based inverters, this installation is not only the first practical demonstration of the UPFC concept, but also by far the highest power GTO-based Flexible AC Transmission Systems (FACTS) equipment ever installed. The installation is the first demonstration of this type of equipment connected in series with a transmission line. The project is a collaborative effort between AEP, the Westinghouse Electric Corporation, and the Electric Power Research Institute (EPRI).

C. Energy Storage and Electric Vehicles

The large scale integration of electric vehicles will provide substantial energy storage capacity mainly at the distribution level. Depending on the number of electric vehicles, the total load on the system will increase as a result of battery charging loads. However, a smart grid may accommodate the electric vehicles and benefit from the energy storage capacity they offer to the network. Examples of the different storage requirements for grid services include:

- Ancillary Services including load following, operational reserve, frequency regulation, and 15 minutes fast response.
- Peak load shaving
- Black start, islanding
- Renewables integration: ramp rate control, solar cloud ride through
- Managing diurnal cycles for wind/solar: large energy capacity, peak shift
- Relieving congestion and constraints: short-duration (power application, stability) and long-duration (energy application, relieve thermal loading).

Some distribution companies have already taken steps towards enabling the utilization of the energy storage technology. Most of the current examples of energy storage projects are on a trial basis. An example of this includes the installation of Flow Batteries in a substation in the UK by Scottish and Southern Energy. The flow battery is capable of supplying 150 kWhr, with maximum output of 100 kW. This is mainly used to supply the emergency load locally in case of loss of supply to the substation [14]. Another example of using energy storage units, is in Ireland to compensate for the wind power output deficit. The total sum of 2 MW batteries are installed for the 6 MW Sorne windfarm in Donegal. The batteries have a high level of efficiency (over 80%) with estimated lifetime of 20 years [15]. In the UK connection points for electric vehicles are now being provided at some car parks in London. The current charging stations are not yet capable of utilizing the stored electrical energy in the car batteries, as the grid is not yet capable of transferring the power from LV to HV side.

IV. BARRIERS OF IMPLEMENTING SMART GRID TECHNOLOGIES

The electrical utility industry must overcome the following challenges to make the Smart Grid a reality:

A. Technology Readiness and Deployment of Technologies still Under Development

Although most of the technologies necessary to build the Smart Grid already exist, the majority of them have not been mapped into the electric power domain. Products for cost-effectively applying some of these technologies in the power system have only become available in the past few years. Due to the nascent state of product availability and pressures to deploy Smart Grid technologies, utilities now often need to work in partnership with vendors to define requirements, provide design feedback and evaluate prototypes. After downsizing and deregulation, many utilities do not have the necessary research and development resources available to make this happen.

The pressures of rapidly deploying smart grid technologies and being first-to-market also generate particular concerns for security; both in the short- and long-term. Knowledge of how to develop secure embedded technology is a scarce and expensive commodity, and neither of these attributes mesh well with a high-pressure, get-it-done-now approach. As a result, many technologies are being deployed with numerous flaws that stem from a hurried and immature process.

Building the necessary controls for strong security into the production process takes time for the vendor and pressure from utility customers. The AMI-SEC Task Force has only recently finalized the first version of the AMI System Security Requirements document. Even once vendors start building a product to the AMI-SEC guidelines, it will take several months for this product to make it to the field and likely several more for the industry to work out any issues with interpretation of the guidance. In the meantime vendors are still making products and putting them into the field, creating a potential need for a significant replacement effort at some point in the future to remove points of vulnerability.

B. Cost of Smart Grid Technologies

Replacing the existing technologies with those that have the capability of falling into the smart grid concept involves a high capital cost. The justification behind smart grid technologies lies behind many assumptions and possible future energy scenarios; such as the existence of a high level of intermittent generation in the system. The affordability of smart grid technologies both to utilities and to consumers must be assessed carefully and due to the uncertainties
surrounding this matter, it will not be a straightforward task. The uncertainty with regard to the benefits that these technologies may offer, in the case that the drivers behind smart grid programme are not as strong as it was expected, makes the utilities reluctant to start replacing their old assets with smart grid technologies.

C. Need for Re-structuring the Industry

The structure of the electricity industry has already changed from a monopoly system to a fully privatized market in many countries. This has resulted in increasing level of competition and efficiency. Current governmental policies are to implement smart grid technologies within the context of the present industry structure. There is industry concern that the multiple handoffs and interfaces inherent in the existing structure may require greater consolidation, for example between networks, metering and energy services provision. Should this happen it is hard to imagine electricity network companies being net losers, though some of the upside opportunities of smart grids might be less available if, for example, their communications systems ended up owned by other parties.

D. Compatibility with Current Standards and Technologies

The ability of the smart grid technologies to interact with other assets is vitally important to the performance of the smart grid. It enables integration, effective cooperation, and two-way communication among the many interconnected elements of the electric power grid. Effective interoperability must be built on a unifying framework of various interfaces, and standards. The main challenge with regard to a unified standard is the availability of various communication options. If each utility applies a different communication technology, they must be able to interact with each other. One of the key objections of utilities to replace their old and ageing assets with new assets which fall into smart grid concept, is complexity and inadaptability of the new assets with current communication, protection, or network management schemes.

E. Lack of Market Power for Smaller Utilities

Deploying advanced technology is easier for larger utilities for two reasons: Firstly, they have more internal resources to apply to the project; and secondly, they must deploy to a larger number of sites and therefore can offer bigger incentives to vendors to implement the features they need. Smaller utilities that do not have such economies of scale, cannot offer large incentives and therefore must often take off-the-shelf technology. This may mean their Smart Grid projects are “not as smart”, or must be deferred because they are not yet cost-effective.

V. CONCLUSIONS

This paper summarizes various emerging technologies within the T&D sector that will contribute towards improving the operation and management of the sector. These have all been classified as Smart Grid technologies and in this paper they were assessed under different categories. Firstly, the challenges for the T&D networks, and the drivers behind implementation of smart grid technologies was discussed. This will see the transformation of the grid from a centrally controlled entity, to several self controlled sub-networks. Technologies which may be used for active network management and control such as demand response, or PMU are introduced and their potential for application is discussed. Technologies that fall under the FACTS area were discussed including SVCs and STATCOMs. Energy storage units provided through conventional methods such as static batteries, or by facilitating the connection of electric vehicles with bi-directional power flow are discussed. Potential barriers for implementing smart grid technologies are highlighted.

VI. REFERENCES


VII. BIOGRAPHIES

Vandad Hamidi received his PhD. in Electrical Engineering from the University of Bath, UK, in 2009 for work on modelling demand response to improve the value of wind power generation. He joined Mott MacDonald’s Power Systems Division in September 2009 where he is a power system analyst in the Brighton, UK office. His work is focused on power system, studies for transmission and distribution network planning, industrial power system design, transient analysis, and the application of Smart Grid technologies. He is a member of the IEEE Power Engineering Society (PES), a member of the IET and working towards becoming a Chartered Engineer.
Kenneth S Smith graduated with 1st class honours in Engineering Science from the University of Aberdeen, UK in 1988, and was awarded his Ph.D. in 1992 for work on the analysis of marine electrical systems. After completing his doctorate he held academic teaching posts at the University of Aberdeen, UK, and at Heriot-Watt University, UK. Since April 2002 he has been with the Power Systems Analysis Section of Mott MacDonald’s Transmission and Distribution Division in Glasgow, UK. Dr Smith is a Chartered Electrical Engineer (UK), a Fellow of the IET, and a Senior Member of the IEEE. He is an Associate Editor of the IEEE Transactions on Industry Applications (Power Systems Committee) and was appointed an Honorary Professor in Electrical Engineering at Heriot-Watt University, UK in 2009.

Roddy C Wilson studied Electrical Engineering at Heriot-Watt University, Edinburgh, UK and joined YARD Limited in 1984. Between 1993 and 1997 he was with Foster Wheeler Energy Limited. Since 1997 he has been with Mott MacDonald where he is presently the manager of the Transmission and Distribution Division’s Power Systems Analysis group. Mr Wilson is a Corporate Member of the IET, a Member of the IEEE and a Charted Electrical Engineer (UK).