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Islands as Test Beds for Innovative Energy Solutions



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FOREWORD

The agreement of Paris 2015 has shown the way towards sustainable development and decisive steps to prevent further adverse change of the global climate. Europe has an important part to play in the implementation of this agreement, not only by supporting developing states in fulfilling their climate goals, but also at home. This publication is part of this effort, showing how sustainable, almost emission-free development can be realized on the Greek islands. As Greece has been in the headlines in recent years for financial and political reasons, the publication tries to highlight the country's positive potential for its European partners.

The publication presents the results of a two-day workshop on »Islands as test beds for innovative sustainable energy technologies«, which took place on 9-10 November 2015 in Athens. The workshop was conceptualized and co-organized by the office of the Friedrich-Ebert-Stiftung in Athens and the Aegean Energy Agency. It brought together an illustrious group of experts on energy issues, representatives of the European Commission, national ministries, local and regional authorities, as well as practitioners from the field of energy business. The discussions concentrated on four issues, which are of central importance for a future sustainable energy profile of the Greek islands: smart grids, storage of electricity, electric vehicle infrastructures and public street lighting in islands. The debate in the workshop focused mostly on the different challenges for realizing technologically feasible solutions, mainly political, administrative and financial. All sessions concluded with ideas for projects and concrete policy recommendations.

The workshop and this publication show that low carbon development is not only possible, but would offer many opportunities for the communities of the islands and the local economy, which is focused mainly on tourism, as well as the national economy of Greece. Available technological solutions would dramatically reduce the cost of energy on the islands, as well as the emissions caused by the transport of oil to the islands and the outdated diesel generators still used to produce energy. Greener Greek islands would offer a better quality of life for their inhabitants, as well as the many visitors coming to the Aegean during the tourist season. In fact, these solutions could be part of a new economic model for these islands, providing sustainable jobs offering qualitative opportunities for a skilled workforce. However, the precondition for that would be a concerted and coordinated effort on the part of civil society, as well as at the national

political level, changing course towards sustainable development on the basis of renewable energy sources.

The publication is part of the focus of FES Athens on »Sustainability and Energy Policy«, which was established with the re-opening of the office in Athens in 2012. Since then we have realized many German–Greek, but also European dialogues on progressive energy policies, the EU 2020 strategy, the German »Energiewende«, climate protection and energy cooperatives in Greece and Germany. The overarching aim of these dialogues is the exchange of experiences and the strengthening of sustainable energy policies on the European level, leading towards a more sustainable Energy Union in the future. Our project is part of a broader FES project focused on the question of how sustainability can become part and parcel of politics and strengthen not only the social dimension of development, but also democratic participation in societies (www.fes-sustainability.de).

Nicole Katsioulis

Friedrich-Ebert-Stiftung, Director Athens Office

FOREWORD

Islands are at the forefront of the global fight against climate change, since they are amongst the first to experience the devastating impacts this has on local ecosystems and livelihoods. While perceived by some as disadvantaged territories, islands' intrinsic characteristics (autonomous systems sometimes hosting most of the infrastructure needed to manage their resources; significant fluctuation of electricity demand due to tourism; very high energy dependence on fossil fuels for electricity production, oil and heavy oil in particular; very high cost of electricity production; huge RES/EE potential; unique but also fragile ecosystems due to unsustainable tourism patterns) proclaim them to be perfect test-beds for innovative technologies addressing real-life challenges. Indeed islands represent excellent laboratories for technological innovation particularly in the fields of energy, transport and mobility, tourism etc.

To accelerate progress towards meeting the EU energy and climate objectives to 2020 and beyond, improve citizens' quality of life and boost local economies by investing in sustainable solutions in a number of vital sectors (energy, water, transport, tourism, agriculture, fisheries and waste management) macro-economics do not provide all the answers. Very often local economies are suffering from political isolation and limited communication among different administrative levels. Enhanced multilevel and multilateral governance can empower local communities and create an enabling environment for regional development and territorial cohesion.

To this end galvanizing support by all relevant players is key. Public administration, regulatory authorities, industrial players and consumers must be part of new schemes of cooperation both in the production and demand side of energy. Other actors who are more political in nature like the **Friedrich Ebert Stiftung** (FES), which supports the publication of this report, can act as catalysts for the wide dissemination of the most efficient models and strategies to transition towards a low carbon economy. European Islands have remarkable, yet largely untapped potential in helping Europe meet its energy and climate targets. First island authorities can take measures to significantly reduce their environmental footprint in sectors like tourism and transport by making more efficient use of their resources and infrastructure. Further islands can be at the forefront of renewable energy development, by exploiting diverse renewable energy sources, i.e. sun,

wind (onshore and offshore), biomass, wave, tidal etc. However it is often not clear whether it should be the state or the market who should take the lead in designing and financing such initiatives. The example of electro-mobility is characteristic. The public sector, traditionally responsible for the governance of infrastructure awaits for the market of electric cars to be established first, while electric car manufacturers anticipate the infrastructure to be in place, before they proceed with investing in fleet deployment. In order to overcome this chicken and egg dilemma and fight against technological conservatism joint ventures involving more parties need to be explored.

More broadly what needs to be in place is a SMART ISLANDS strategy, one that applies an integrated approach to islands' development, by highlighting the links between energy flows, natural resources management and technological innovation. A SMART ISLANDS strategy can provide island communities with proper tools to help exploit their potential and maximize the benefits for local economies and communities and should be therefore promoted and adopted at EU scale.

To sum up, this report has been designed and written in order to serve as basis for discussion during the workshop "**Islands as Test Beds for Innovative Sustainable Energy Technologies**" organized by FES and the Aegean Energy Agency that took place in Athens, Greece, in November 9-10, 2015. In the course of the workshop participants identified barriers (technological, institutional and financial) related to the penetration of the innovative energy technologies such as smart grids, storage of electricity, electric vehicle infrastructures and public street lighting in islands, and suggested solutions, taking into account islands' inherent characteristics. Many of the comments and suggestions proposed during the workshop have been included in the report.

Ilias Efthymiopoulos
Aegean Energy Agency Director

1. SMART GRIDS FOR SMART ENERGY SOLUTIONS

Summary

From both an economic and an environmental perspective, electricity networks need to be smart enough to allow a high penetration of power produced from decentralized renewable energy applications into the electricity grid – a high priority EU policy issue – without jeopardising the security of supply required by the end-user (consumer). A more dispersed model of distributed generation will emerge as soon as heat pumps, micro-grids and electric vehicles proliferate, placing complex new electricity demands on the grid while potentially offering the benefit of new storage capabilities to the network.

Smart grids are the way to unlock the full benefits of distributed energy resources in cities, islands and isolated systems. The coordinated operation of the various distributed generators and loads (consumers) increases efficiency and provides opportunities for better network management.

The bulk of smart grid technologies among others include: Data management and communications: Substation automation, demand response, distribution automation, supervisory control and data acquisition (SCADA), energy management systems, wireless mesh networks and other technologies, power-line carrier communications and fibre-optics.

Sensing and measurement: Evaluation of congestion and grid stability, monitoring equipment health, energy theft prevention and control strategies support. The related technologies include: Advanced microprocessor meters (smart meters) and meter reading equipment, wide-area monitoring systems, dynamic line rating, electromagnetic signature measurement / analysis, time-of-use and real-time pricing tools, advanced switches and cables, backscatter radio technology, and digital protective relays.

Smart meters: A smart grid often replaces analogue mechanical meters with digital meters that record usage in real time. Advanced Metering Infrastructure may provide a communication path extending from power generation plants, at one end, all the way to end-use electrical consumption in homes and businesses.

Energy Control Centres: In the case of non-interconnected islands the efficient management of their systems calls for the implementation of dedicated infrastructure, collectively referred to as Energy Control Centres (ECCs). Their purpose is twofold:

- Manage the power plants of each NII, including conventional units, RES plants and storage, aiming to increase RES penetration in a safe and economical system.
- Enable the implementation of market processes, in line with the relevant provisions of EU directives and the national legal and regulatory framework for the organisation and operation of the electricity sector in the NII systems.

Although the deployment of smart grids will lead to overall macroeconomic benefits, it should not be forgotten they are only one part of the solution for making energy networks future-proof. The majority of Europe's existing energy infrastructure is relatively old and needs replacement. The International Energy Agency estimates that, in total, European DSOs will need to invest 480 billion euros by 2030.

Besides this large amount of necessary investment both for infrastructure and technology development, regulatory and market barriers, as well as technical limitations and consumer acceptance, constitute non-negligible barriers to the deployment of smart grids.

Direct load control (DLC) envisages the system operator or the supplier remotely disconnecting customers' appliances or reducing their consumption, for instance, via change of temperature in a thermostat or switching off a particular appliance normally at short notice or controlling loads such as off-peak water heating and air conditioners without inconveniencing the consumer. Smart meters can enable such programmes, providing an appropriate communications infrastructure within the home to control appliances. Using smart meters could facilitate optimization of network management, thus avoiding unnecessary investment in building further network capacity. Smart meters also have potential to increase the ability of the system to accommodate a range of future energy scenarios, accommodate electric vehicles to grid applications and contribute to demand-supply balancing. This is especially important in light of multiple commitments all over the world to improve energy efficiency, reduce energy consumption and reduce emissions.

The purpose of electronic smart meters is to provide information related to the energy consumption of each consumer. These meters may change consumers' energy consumption habits in the short term and also provide an important step towards the creation of smart grids in the future. This particular technology will help consumers to reduce their electricity bills and contribute to the reduction of carbon dioxide emissions.

Bills with estimated consumption, based on the past year's consumption, would no longer be issued. The consumers themselves would be able to manage their consumption (and energy costs) more efficiently and it will become easier for them to select and switch between different energy suppliers. On the other hand, energy suppliers would be able to offer a wider range of reduced-cost packages, including the supply of energy during off-peak hours.

In concrete terms, in order to achieve the above, electronic LV metering devices will be installed for all users, replacing existing metering devices where needed. In addition, meters and surge protection devices can be installed at distribution (MV/LV) substations of the selected areas, using current transformers of the appropriate ratio, in order to contribute to the LV network monitoring. The central systems to be developed comprise the AMR (automated meter reading) and EDM (energy data management) system components.

AMR will be responsible for the collection of metering data from the field, supporting a wide range of electricity metering devices. Driven by local time schedules, the system will collect data from all metering devices through pre-defined communication channels. The AMR system will consist of a central server, modem servers and user workstations, all operating on a network through common software.

The central data collection server is the main component of the AMR system, since it will manage access to the database, communication procedures and operation of the workstations. All programmed functions, such as data reading, creating reports and data checking will be performed automatically, according to pre-programmed schedules. Redundancy and contingency handling capabilities are embedded in the system. Connection of the AMR system to the metering devices will be performed via modem servers. Data acquisition will be possible through different communication channels. All functions will be controlled by the central

server. The user will define the data acquisition procedure, the modem servers and the metering devices that will be enabled and will supervise and validate the data acquisition results.

The data from the AMR subsystem are stored in the database of the central EDM system. The EDM system, using predetermined algorithms, will check, repair, supplement and validate all metering data (load curves, cumulative electric energy data and so on) and automatically generate relevant reports. The final validated data can then be used for market purposes (clearing, billing and so on).

Smart meters and the technological field of telemetry play an important role in reducing energy consumption and carbon dioxide emissions. They also improve the quality, accuracy and range of services provided by energy suppliers. In the long term, telemetering will become a very important factor in the creation of smart energy grids.

One of the main tools used for implementation of the open energy market is the metering device, combined with the related recording and data acquisition equipment, which constitute an integral part of the advanced meter infrastructure (AMI) system, as well as the meter data management (MDM) system.

1.1 Potential offered by Smart Meters for DSM

Taking into account the EU Internal Electricity Directive (2009/72/EC), which states that: "Member States shall ensure the implementation of intelligent metering systems that shall assist the active participation of consumers in the electricity supply market", smart meters will be key potential enablers for home automation technologies and thus for direct load control. Smart meters can facilitate demand-side management programmes by allowing monitoring energy consumption on at least an hourly basis and having a two-way communication capability with utilities and distributors.

Demand-side management (DSM) programmes can bring a range of benefits across the entire value chain. A study carried out by Commission for Energy Regulation and Utility Regulator in Ireland outlined the benefits that the demand response can bring:

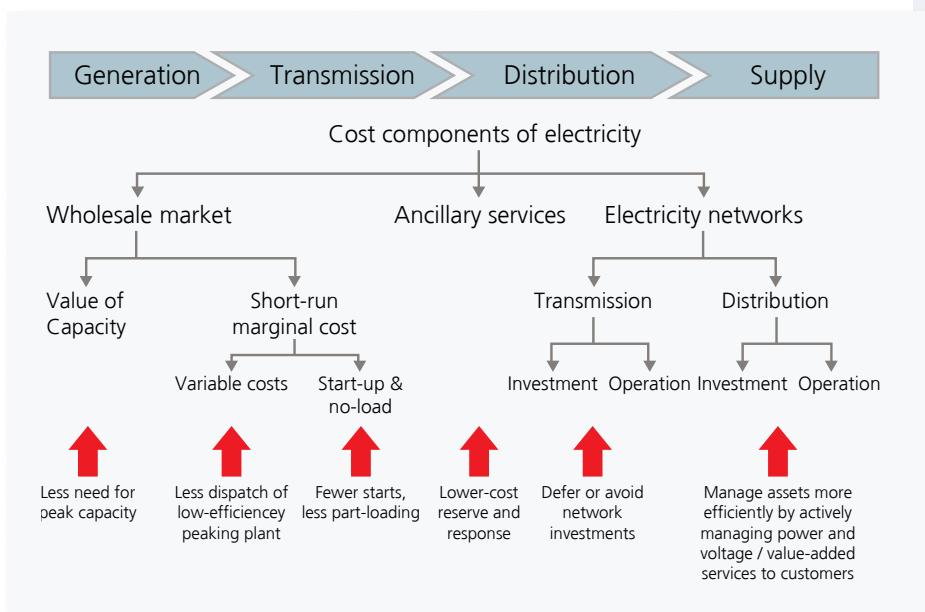


Figure 1: Demand-side flexibility benefits across the electricity value chain

Source: KEMA report on smart grid development in five Aegean islands

Germany – MeRegio project

The project is being led by six partners: EnBW (project leader), ABB, IBM, SAP, Systemplan GmbH and KIT (Karlsruhe Institute of Technology). MeRegio involves building a smart grid infrastructure which will allow real-time communication between energy consumers, multiple distributed energy resources and smart storage devices. The project involves 1,000 private and commercial participants. Customers are given a control box that receives the weather-dependent price signal. This makes the smart electricity meter even smarter as it can be programmed and directly control individual electronic appliances in the home. The project incorporates dynamic rates and will use existing and emerging technologies for distributed energy resource integration and communication platforms for smart metering and distribution automation. This is expected to result in the preparation of new industry standards in the area of smart metering and home automation.

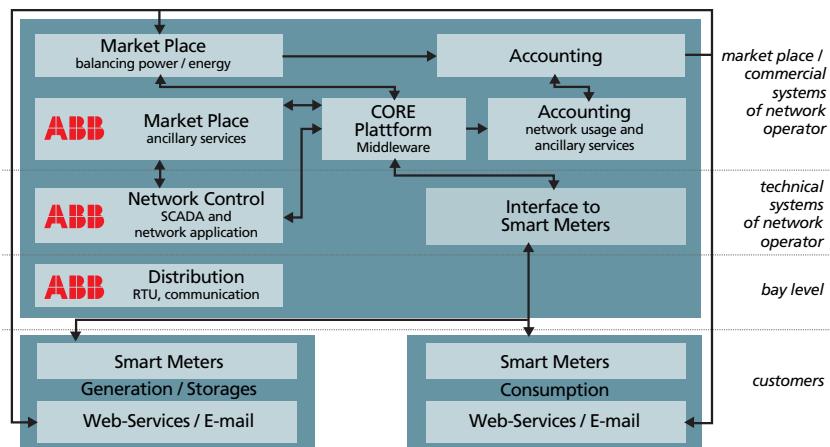


Figure 2: MeRegio system structure

Source: <http://www.meregio.de/en/index.php?page=solution-phasetwo>

Number of participants	<ul style="list-style-type: none"> • 1000
Partner	<ul style="list-style-type: none"> • EnBW, Bosch, Stadtwerke Karlsruhe, Fraunhofer Institut, University Karlsruhe, Daimler, Opel, SAP
Demand Response appliances	<ul style="list-style-type: none"> • Electric Vehicles • Dishwashers • Washing machines
Tariff, billing	<ul style="list-style-type: none"> • ToU • Use of "green-energy" tariff
Communication	<ul style="list-style-type: none"> • Broadband communication, CIM and IEC 61850; OpenSmartGrid, XML and WebServices

Table 1: Fact sheet - Germany

Demand-side management programmes can bring a range of benefits across the entire value chain. Several studies were carried out to examine the potential for energy consumption reduction using smart meters for demand response management. According to the studies general energy efficiency measures, including critical peak pricing, can bring savings in the range of 5–15 per cent of total customer demand, whereas when combined with home automation and industrial settings savings can increase by up to 80 per cent.

These are schemes in which household appliances can be controlled by a utility or network company and/or automated devices can be programmed to respond to prices, curtailing their own consumption during peak periods. On average across studies home automation in the domestic sector achieved around 25 per cent energy reduction of the load participating in the demand response programme, whereas peak power was reduced by 80 per cent (using home automation) and shifted to the off-peak period. In the commercial sector, using demand-side flexibility, the programme achieved 25 per cent reduction in energy consumption. In warm countries, control of air-conditioning was proved to be a significant source of load reduction by the domestic sector. This is a significant conclusion in relation to Greece.

In colder countries, on the other hand, control of space heating and water heating appliances is more common. Meanwhile, the energy reduction potential with regard to controlling/programming dish washers and washing machines is still being explored.

A study of the UK demand response potential showed that around 9 and 17 GW of »discretionary« load could be »time-shifted« to a different time period or forgone completely. Most of this load (around 66 per cent) is used for lighting; the weather in the United Kingdom is less extreme and most residential flats do not use air-conditioners; there is also less reliance on electricity to provide heating. The study carried out by Imperial London College demonstrated that the optimization of responsive demand has the potential to reduce the system peak and the need for system reinforcement. The analysis of household appliances (washing machines, dishwashers) potential for demand response showed that with 20 per cent penetration (a share of households that own the appliance) the estimated peak reduction is 8.4 per cent, whereas a 100 per cent penetration would achieve 15.8 per cent peak reduction. When combined with electric vehicle

and heat pump control capabilities, the value of smart management of demand, enabled by an appropriately specified smart metering system is between £0.5 billion and £10 billion (€0.6 billion–€12 billion) for the United Kingdom in net present value terms.

According to the analysis carried out by the US Federal Energy Regulatory Commission (FERC) in 2011, the direct load control programme has the highest potential to reduce peak load when it comes to residential consumers. Figure 3 provides an overview of potential peak load reduction by type of programme and by customer class according to FERC survey. The survey covers the whole of North America. It is an obligation on the US Energy Commission (FERC) to carry out a demand response and advanced metering survey every year. It covers 3,454 organizations in total. Questionnaires were sent by e-mail to all the organizations and also by post, where the company did not have e-mail. Organizations that did not respond on time were contacted by phone. Adjustment mechanism was used where answers were missing.

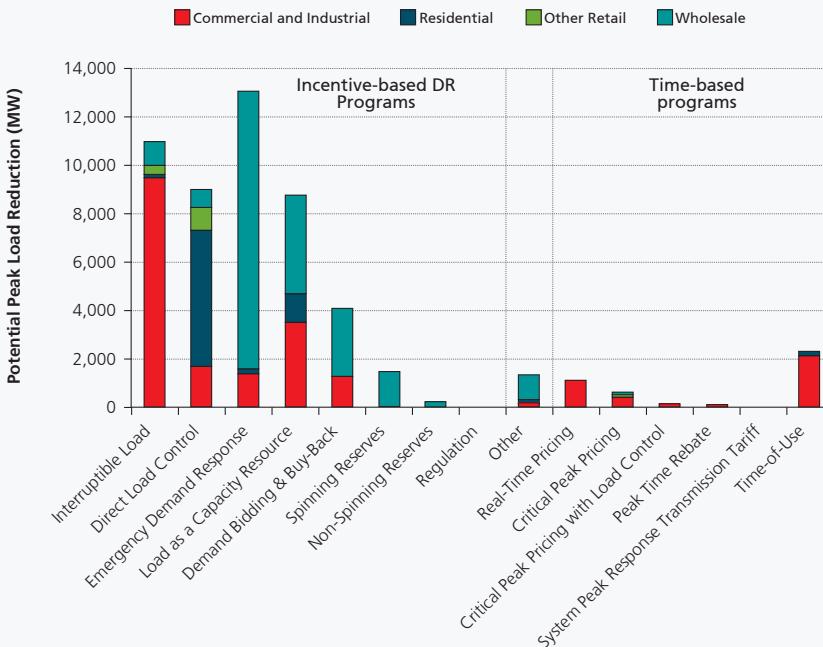


Figure 3: Potential peak load reduction by type of programme and by customer class

Source: US Federal Energy Regulatory Commission (FERC)

According to the international experience of the demand response project, energy savings were delivered in the amount of 20–50 per cent, the latter being automated energy reduction. It is worth noting that many of the projects experienced technical difficulties and challenges when installing and using the technology, but these were resolved as the projects progressed.

It is also important to keep in mind that the potential for demand-side resource management tends to be higher than can be realized. Therefore, the party that plans to implement a demand-side programme needs to identify what proportion of this response can actually be realized in a cost-efficient way. It was also found that advertising of schemes is short-lived and interest in in-home displays or other feedback technology also declines after a time, so additional measures are needed to maintain consumer engagement over longer periods. According to FERC, the potential for demand response in 2011 among utilities that already have these programmes in place averaged around 7 per cent of peak demand in 2010.

1.2 Remarks – Preliminary Conclusions

Although demand response has been widely used for several years worldwide, and smart meters – many with demand response capabilities, as in Italy and Spain – are being rolled out in many countries, led by regulatory legislation, active demand response via smart metering is still being explored and piloted. Such solutions are usually implemented by utilities, rather than nationally, as standards for communication technology and smart appliances are still being established.

During an examination of international projects, it was found that, overall, different solutions are being used by the utilities as they enter into agreements with smart meter, software and telecommunication companies of their choice. Furthermore, during pilots it was concluded that a well-established communication network is required to implement direct load control via smart metering systems, as some projects experienced technical difficulties during trials.

In December 2011, the Council of European Energy Regulators (CEER) published advice on launching a demand response electricity market with smart meters with the aim of enhancing the implementation of demand response with household

customers and small and medium-sized businesses. CEER prepared a dedicated online questionnaire for interested stakeholders and they received 44 responses from utilities, meter manufacturing companies and others. As a result of the responses the final advice described the roles and responsibilities for different market actors in realising demand response. Customers, micro-generators, metering operators, DSOs (distribution system operators), suppliers, ESCOs (energy services companies) and NRAs (national regulatory authorities) were recognized as the key enablers of demand response. It was suggested that the customer is the crucial player as without customer awareness and participation, demand response will not come into practice.

It is also recommended that to enable a wider scale demand response via smart meters, smart metering systems should be capable of recording a configurable time basis on at least an hourly basis with capacity in line with the meter reading frequency and use of ToU registers with at least three registers for peak, middle level and off-peak. To enable direct load control, the meters provided should be equipped with or connected to an open gateway. The Council also suggested that, to enable the take-off of demand response, offers should be developed that reflect actual consumption patterns, as well as having an interface with the home. The customer would need to have access to the open gateway.

Such an approach would not give the DSO a privileged position compared with other service providers. The gateway would need to have a standardized interface which would enable energy management solutions (such as home automation) and different schemes on demand response, as well as facilitate direct delivery of data. Finally, a national hub/database is needed where relevant metering data can be accessed by the relevant stakeholder. Such information should be subject to customer consent.

Special plug-in devices that can receive a signal from a smart meter to cut off supply to appliances are emerging as a cost-effective tool for residential and small commercial customers. Generally, it takes around 10 to 20 minutes to reach 90 per cent of end appliances, whereas the duration of the command is around 15–60 minutes for over 1,000 customers for mesh or mixed PLC/GPRS architecture. Overall, demand-side management programmes have achieved significant savings of energy at around 20 per cent, rising to around 50 per cent with home automation.

It can be concluded that smart meter–enabled direct load control projects make it possible to recognize the specific conditions of individual LV sections, depending on the real-time behaviour of time-varying loads at each location. This is important for enhancing utilization of existing assets and thus avoiding network reinforcements.

1.3 Pilot Smart Metering in Greece

In Greece, an investment plan will be implemented by 2016 in five islands, as well as in selected representative urban and rural areas on the mainland:

Breakdown of smart meters per geographical area:

Geographical area	Region or prefecture / local authority	Number of LV Meters
North Aegean	Lesbos Island	~ 66,000
North Aegean	Limnos Islands	~ 13,700
North Aegean	Agios Efstratios Island	~ 300
Ionian Islands	Lefkada Prefecture	~ 20,000
East Macedonia-Thrace	Xanthi Prefecture	~ 60,000
Athens	Attica	~ 7,000
Thessaloniki	Central Macedonia	~ 3,000
Cyclades	Thira Island	~ 17,000
Cyclades	Kythnos Island	~ 3,000
Cyclades	Milos Island	~ 10,000
Total		~ 200,000

The operations and maintenance services (O&M) costs correspond to five-year provision of services for operation, technical support and maintenance, as well as for services of fault recovery for all metering and communications equipment, including the cost of telecommunication services. This is an integral part of the investment package, guaranteeing the good operation of the equipment that will be installed.

The tender also foresees that during the five-year period, 25,000 more smart meters (5,000 per year) will be required and installed; the cost of their procurement, installation and integration into the system will be €5 million. It also assumes that during the extension option for five more years, another 25,000 smart meters will be required, again at a cost of €5 million.

The total cost of the tender and the investment is estimated to be €86.5 million, including O&M services. The three islands of Kythnos, Milos and Santorini are options, with a main cost of up to €10 million, including operations and maintenance services. The financing plan foresees a grant of approximately 52 per cent from the Community Structural Funds (state aid approved by the EC) and the remaining amount will be covered by HEDNO's internal funds and external financing sources.

1.4 Energy Control Centres for non-interconnected Islands

In the abovementioned project in Greece, islands are a distinctive group, given the specific structural and operational characteristics of the grid and their autonomous power systems. In the so-called non-interconnected islands (NII), in contrast to the mainland system, and taking into account the high RES penetration levels already achieved, as well as the existing potential for further increase, the efficient management of their systems calls for the implementation of dedicated infrastructure, collectively referred to as energy control centres (ECCs). Their purpose is twofold:

- Manage the power plants of each NII, including conventional units, RES plants and storage, aiming to increase RES penetration in a safe and economical system.
- Enable the implementation of market processes, in line with the relevant provisions of EU directives and the national legal and regulatory framework for the organisation and operation of the electricity sector in the NII systems.

The ECCs have now become a formal obligation of the NII system operator (HEDNO S.A., a 100 per cent PPC S.A. subsidiary), by the recently (2/2014) established Code for the management of NII power systems. Based on that, a

European Commission funded project (Intelligent Energy, ELENA) was initiated in order to design and implement integrated smart grids in the five abovementioned Aegean Sea islands which are taking part in the pilot project for smart metering. The Code, fully adopting the ECC architecture designed within this ELENA project, stipulates the development of a central ECC and local ECCs to support the role of the NII system operator.

The central ECC will be located at HEDNO premises in Athens and will include several systems to perform implementation of market operations, including billing/settlement and metering functions, and the supervision of the NII power systems' operation. More specifically, the central ECC will be responsible for the preparation of »day ahead scheduling« (DAS), the supervision and optimisation of autonomous systems' operation and NII market settlement. Moreover, it will be duplicated in the Emergency Backup Central Control Centre (EB CCC).

One local ECC entity is foreseen for each NII system (hence, five local ECCs in total for this project). Each local ECC constitutes the infrastructure for the management of the respective NII power system and communicates/cooperates with the central ECC, which monitors its operation. Local ECC infrastructure will be located on the respective island, at an agreed location in the local thermal power station. Each local ECC will monitor and control in real time the operation of local power plants and will communicate with the central ECC for the implementation of day ahead scheduling. For the big islands or for islands with special requirements, a local control centre (LCC) may be hosted on the island, operating as a manned local dispatch centre. For all the other NIIs, the local ECC will comprise mainly automated systems, supervised by the local power station personnel.

The central and local ECCs shall operate as complementary systems for the respective NII. Furthermore, they will always be updated with the status of the electrical system and synchronised to each other in order to be ready to change their operational status when needed.

Systems architecture

Figure 4 presents a conceptual architecture (local – island – central) for the systems infrastructure of the central and local ECCs to be developed, as designed within the ELENA project. The main systems at the central ECC are as follows:

- MMS (Market Management System) for implementation of market processes.

It is practically included in the central ECC, with the option of limited functionality in the island systems. The MMS also includes the interface for the submission of offers and the publication of market outcomes.

- EMS (Energy Management System) for performing the operation and control of the autonomous power systems of the NII. It is included in both the central and local ECCs.
- Metering for the collection, processing and publication of the energy metering data from the energy counters.
- Settlement for performing market settlement.
- Helpdesk for supporting internal and external users of the IT infrastructure.
- HIS – DW (Historical Information System – Data Warehouse) for keeping historical information and aggregate data available to users for periods ranging from a few months (HIS) to a few years (DW).
- Portal & Internet for communication with market participants (offers submission and market results publication).

The island systems, which are shown in the middle level in Figure 4, represent the local ECCs, operated by the island operators. They include island EMS and partial MMS functionalities, and communicate with both the central systems (upper level) and the local systems (lower level). The latter typically consist of the power stations, renewable energy sources installations, such as wind and photovoltaic (PV) stations, and local control systems (LCS) in high voltage (HV) substations. The architecture allows for parallel communication between the central and the local systems. A telecommunications backbone will ensure reliable communication between the central and island/local infrastructure. This infrastructure is not part of the abovementioned project tender, as it will probably be provided by a telecom service provider and the NII system operator.

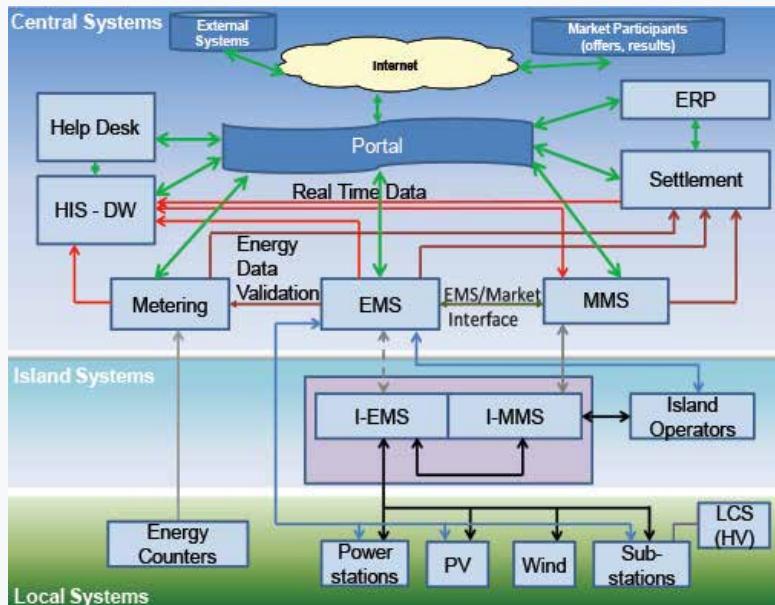


Figure 4: Indicative architecture of a typical ECC infrastructure

Source: Ecco International: Development of smart grid infrastructure

in autonomous islands of the Aegean sea

Main ECC functionality

ECC functionality refers to the following two main areas. At first, the introduction of market functionalities is new to the NII. Although the market framework is simpler than those of large mainland systems, most of the functionalities of a commercial market management system need to be specified in order to address the Code Requirements. Secondly, the NII power systems used currently are operated by the respective autonomous power stations (typically one thermal station per island). Under the new framework, this responsibility is undertaken by the NII operator. This transition requires the specification of an energy management system, which will be in the jurisdiction of the NII operator, whereas the existing power stations' capabilities will be maintained in operation to deal with emergency cases (for example, a loss of communications). The presence of intermittent renewable energy sources (RES) requires close supervision of the NII power system to ensure secure and reliable operation.

Market processes

The following market functions will be developed and implemented in the ECCs, consistent with the recently established Code for the NII:

- Rolling Day Ahead Scheduling – This function performs the unit commitment and dispatch of the generation units of each NII system, for a 24-hour horizon of a calendar day (from 00:00 to 24:00), on an hourly basis, for the day ahead. The scheduling is updated once during the day, for the second half of the day (from 12:00 to 24:00).
- Dispatch Scheduling and Real-Time Dispatch – The preparation of the dispatch schedule follows the basic rules of the rolling day-ahead scheduling. It takes into account the actual data, as they have been updated by the continuous communication of the network users with the NII operator, and refers to the unit scheduling for the horizon of the next four hours. This process runs on a continuous basis every 20 minutes. Real time dispatch is the function that takes place between 1 and 5 minutes. The time horizon of real time dispatch could extend to 1 hour to incorporate future load forecasts.

The sequence of market phases is presented in Figure 5. It illustrates the interaction of market functions with the system's operation and metering infrastructure. The market participants submit their energy offers (unit availability, daily energy offers and hourly generation schedules) for rolling day-ahead scheduling and dispatch scheduling and are notified about the scheduled quantities. The schedules and set-points are sent to the market management system, which in turn feeds the real time dispatch process with real-time values and operating constraints. Billing and settlement are performed using the metering data and the payments/bills are made/sent to the market participants (generation/load entities).

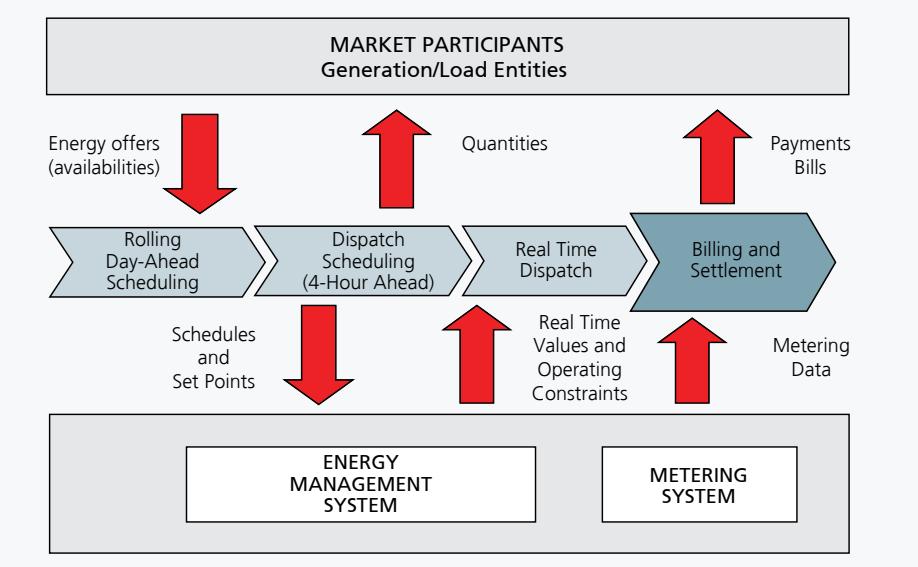


Figure 5: Sequence of market processes and system operations

Source: Ecco International: Development of smart grid infrastructure

in autonomous islands of the Aegean sea

Power System Operations

Power system operations include the following basic functions:

- Forecast applications: This includes functionalities for performing short-term load forecasts and renewable energy source generation forecasts to be used as input to market processes.
- Automatic generation control: This is the primary function of the power system operation to ensure load-frequency control.
- SCADA infrastructure: The SCADA functionality includes the communication of the central system with the remote terminal units of the network and stations, the collection of real-time measurements from power stations, RES and storage plants, as well as the supervised elements of the network.
- Power and network applications: These functions use a network model and the real-time data from the SCADA system to identify and supervise the state of the power system in real-time, examine whether security of supply is ensured under actual operational conditions, as well as under conditions planned for future operational conditions (for example, day-ahead), and determine preventive and/or corrective measures to minimize identified

risks. The system operation applications may include: state estimation; power flow; optimal power flow; short circuit analysis; voltage security assessment / transient stability analysis; contingency analysis and security analysis; disturbance data collection and analysis; outage scheduler.

- Historical information: The historical information system is usually embedded in the EMS functionality.

The contribution of ICT

ICT & Telecommunication technologies today provide a range of capabilities and features:

- High availability and resiliency: Fibre rings with automatic protection switching is a recognized high resiliency solution for communication networks. For example, there are companies which possess and operate extensive network of fibre rings connecting Greek islands over diverse paths. In case of failure on the main path, switching to the protection path takes place in less than 50 msec, while Transmission Control Protocol and Internet protocols (TCP/IP) ensure that no information loss or performance degradation is experienced by the application layer. Wireless backup links also exist in a lot of cases. This architecture guarantees extremely high availability with virtually no downtimes. The use of Telecom infrastructure (out-of-band) rather than conveying data modulated in-band through the grid power lines has the additional advantage that exchange of critical status and control information is unaffected by failures on the grid.
- High capacity and low latency: capacity and transmission speeds ensure minimum round-trip latency for exchange of information/response between the Electrical Grid / Smart Loads and ECC ICT platform, regardless of their location. This can ensure round trip latencies of much less than 100 msec between any two locations.
- Virtualization: the ECC software applications and data are completely decoupled from the underlying hardware resources (processing, storage, networking) that support them and can be served at any time by the required portion from a pool of such resources within a Data Centre to guarantee the desired performance. This enables much more cost-effective scaling of ECCs to more than one islands, rather than building ECC infrastructure on dedicated hardware platforms per islands. Each ECC software and data platform instance is making use of a virtualized portion of h/w resources which can be shared and dynamically re-allocated between instances

depending on the needs. Virtualization is the basis for economies of scale. Maintenance costs are also considerably reduced, since infrastructure is centralized, while superior availability and performance SLAs can be supported. Infrastructure and/or Platform can also be provided as a Service therefore enabling to choose the right trade-off between investment costs and operational expenses.

- Ubiquitous access to information from anywhere: Cloud ICT architecture permits ECC workplaces to reside anywhere with instant and guaranteed access to information from the ECC platform and the grid.

It is evident that the optimum combination ensuring the lowest Total Cost of Ownership, scaling to many islands and enabling high performance service level agreements can be achieved by pooling the ECC platform ICT infrastructure centrally, while workplaces can reside centrally, locally or both according to the availability of skilled human resources. Communication networks ensure ubiquitous, uninterrupted and real-time exchange of information among all components. Today's ICT technologies based on Cloud, Virtualization, Internet of Things, Broadband/Mobile communications are mature enough to support systems of the complexity envisaged in a Smart Grid. Focus should be on careful system planning & integration and of course on the development of the management and control logic in software.

Finally, Comprehensive cost-benefit analysis should take place, determining and quantifying the benefit that can be created by smart grid capabilities for each market stakeholder: End user/Consumer, Supplier, Market Operator, DNO, TSO, Producers (thermal and RES), other (e.g. ESCOs). This is essential in order to assess willingness-to-pay of each stakeholder and plan realistic recovery of investments.

The share of smart meters in the new market

Confusion often arises between the terms »smart meters« and »smart grids«. While intelligent meters represent one of the central components of a smart grid, they cover only one part of the technologies needed to add intelligence to the grid. The EC's Third Energy Package provided that 80 per cent of consumers should be equipped with smart meters by 2020, with the prerequisite that a national cost/benefit analysis shows positive results.

For consumers (in combination with in-home displays), smart meters deliver more detailed information on energy consumption and production. For network

operators, smart meters provide all kinds of quality information on the network (outage, voltage level and so on). Additionally, smart meters are important tools for all kinds of commercial service providers; for example, demand-response service providers use the data to create incentives for consumers to adapt their consumption according to price signals.

The roll-out of smart meters therefore has to be seen in a differentiated manner, from a smart grid and smart market perspective. Merely from a grid perspective, smart meters are not needed in every household to maintain grid stability and security. For residential areas with small single family houses and similar consumption patterns, for example, some central metering points (for example, on street level) may suffice for secure and reliable grid operations.

However, from a smart market perspective, a national or consumer-segmented roll-out of smart meters is indispensable. Only with close to real-time information about energy consumption and variable prices will interested consumers be able to react to real-time price signals and demand-response services from energy service companies (ESCOs). However, many smart meters installed are not yet fit for these purposes.

Therefore it is advisable, in a first phase, to identify new demand-response/customer services and ancillary services provided by DER and, from these, to derive the technical characteristics required from the new meters. This is equally applicable to smart appliances, which can deliver consumer benefits, for instance by shutting off devices at times of high price signals; they therefore form part of a smart market, rather than a smart grid.

Increasing system flexibility

With increasing flexibility in energy supply, new demand-side services – demand-response programmes – are becoming more important. In its recently published Communication on optimising public intervention, the European Commission estimates the controllable load in Europe to amount to at least 60 GW. Shifting loads from peak to off-peak times could reduce the need for peak generation capacity by 10 per cent. Demand-response therefore potentially entails further benefits, such as avoiding grid reinforcement, reducing consumer bills and higher overall system efficiency.

Industry and SMEs certainly display the largest potential for supplying flexibility by shifting loads; however, through aggregation, private households can also contribute to demand-response programmes. Traditional energy suppliers will be among those to offer their customers new products and services; but also new actors, such as aggregators and specialized ESCOs, will make contracts with consumers for these energy services and benefit from the deployment of smart grids. As these services can also benefit DSOs in the operation of networks (for example, by enabling their purchase as ancillary services), a clear and transparent market design needs to be found and new roles and responsibilities for all actors need to be defined thoroughly. Having the ultimate responsibility for the reliability of the network, which is essential for all market players but especially consumers, it is a prerequisite that DSOs must at all times be informed about the actions of market actors and about the dynamics in the grid.

ADVANTAGES OF SMART GRIDS

- Contribute to energy and climate targets
- Enhance security of supply
- Connect electricity, gas and heat networks
- Empower consumers to play an active role
- Facilitate system management
- Link the power and transport sectors
- Create new markets, jobs and growth

The pre-conditions for maturity

Although the deployment of smart grids will lead to overall macroeconomic benefits, it should not be forgotten they are only one part of the solution for making energy networks future-proof. The majority of Europe's existing energy infrastructure is relatively old and needs replacement. This applies to Greece, too. The International Energy Agency estimates that, in total, European DSOs will need to invest 480 billion euros by 2030.

Besides this large amount of necessary investment, regulatory and market barriers, as well as technical limitations and consumer acceptance, constitute non-negligible barriers to the deployment of smart grids.

1.5 Regulatory Frameworks

As distribution systems are natural monopolies, their operation is regulated. The costs of DSOs are remunerated through the network tariffs paid by consumers. National regulators determine the tariff level and thus the allowed revenue for DSOs over a specific period of time. In most regulatory frameworks incentives for cost-reductions are given, putting the focus on efficiency and short-term cost reductions, including sanctions in case of non-compliance. Given the need to replace Europe's aging energy network infrastructure, a drastically changing generation landscape from centralized to decentralized, and investments shifting from reinforcement and extension to adding an ICT layer to the traditional copper lines, traditional regulatory frameworks increasingly appear to be inappropriate to cope with these realities.

In many European countries, network tariffs are 100 per cent volume-based, meaning that network tariffs are charged for each kWh used. With an increasing share of so-called "prosumers" and through successful energy efficiency measures, less electricity, gas and heat are transported through the networks. While this is contributing to the EU's energy and climate objectives, it dramatically decreases the revenue of DSOs. At the same time, the network needs to be maintained, reinforced and extended and even consumers with micro-generation facilities will continue to be dependent on the grid during certain times of the day. Moreover, for DSOs the cost driver of the network is supply of (peak) capacity and not volume.

Therefore, a mixed tariff structure based on the capacity of the connection and the volume used, may constitute an interesting alternative, allowing network operators to recover their costs in a more balanced and consistent way (see, for example, the Netherlands). In order to incentivize the necessary investments for the deployment of smart grids in Europe, the EC advocates cost-reflective regulatory frameworks that recognize investments in innovative technologies, adapt to changing structures and minimize the time delay between investments and adaptation of revenue caps.

Apart from adequate incentive regulation frameworks, supporting funding for smart grid demonstration projects has been provided by some national regulatory authorities (NRA), which has led to good results. With good technical develop-

ments, a shift from the R&D focus to the demonstration focus of projects can be observed. Currently, 80 per cent of all projects still depend on public funding. Therefore, better access to public funding for small and medium-sized pilot projects should be ensured.

Consumers acceptance

Consumers and their attitudes to smart technologies will play a central role in the deployment and success of smart grids. As the Council of European Energy Regulators (CEER) established in its discussion paper for a 2020 customer vision, the involvement of consumers in the energy market has traditionally been very low. They have been mere users of energy at the end of the supply chain. Therefore, the European Commission's Task Force for Smart Grids emphasized that with the introduction of new technologies, such as smart meters, home automation and micro-generation plants, consumer information, engagement and education are the key tasks in order to tackle concerns about technology complexity, privacy and data protection.

In order to actively participate in the energy market and to tap the potential benefits of smart grids, consumers rely on sufficient, simple and transparent information, attractive, reliable and secure products and services, as well as incentives to use them. DSOs have always been very close to consumers in their region through their long-term relationship with them; the energy networks being a natural monopoly, switching DSOs is not possible for consumers. DSOs are therefore ideally placed to link consumers and the energy market. The fact that DSOs are especially consumer-oriented is proven by the fact that most smart grid projects currently running with a special focus on consumer involvement are led by DSOs and this number has been growing significantly in recent years. In particular the issue of data management and privacy is pivotal for DSOs in this regard. In order to ensure compliance with data protection rules and thereby create acceptance on the consumer side, clear rules and responsibilities with regard to data communication need to be established.

Smart grids for smart markets

Against the background of the envisaged completion of the internal market for energy, the European Council confirmed the need for common standards for smart grids in February 2011. Following a Commission Communication of the same year, the European standardization organizations CEN, CENELEC and ETSI

were given a mandate to develop a first set of standards for smart utility meters, communication protocols and other functionalities in order to guarantee interoperability of equipment. Although this first set of standards was published in 2013, standardization, for instance for demand-response services, is still pending. As for smart meters, it is important that first movers are not put at a disadvantage. In the conventional energy system, the typical large-scale generation plants were connected to the transmission networks. TSOs have been responsible for balancing demand and supply and congestion management for which they have a set of instruments. The main task for distribution system operators was to deliver energy to end-consumers, guaranteeing security of supply at all times, with limited tools. With more distributed resources connected at low- and medium-voltage levels, DSOs now face increasing dynamics and new complexity in their networks. In order to be able to actively and efficiently manage their system while offering reliable and high-quality services, they require flexibility instruments, similar to those of TSOs. Distributed energy resources also offer the possibility for system services that could facilitate system management. For example, DER services can be used to solve short-term problems in the grid, optimize the cost of maintaining the desired quality of service, reduce grid losses and reduce or postpone future investments.

In a system with new technologies, such as electric vehicles and variable energy sources, where flexibility is key and market and system functioning undergo significant changes, DSOs are becoming active system managers and »agents managing a local market«. Due to their single main task – secure and reliable distribution of gas, electricity and heat – DSOs will play the most central role in the deployment of smart grids. Based on their eminent position as natural monopoly and highly-regulated party, they are the interface between smart grids and smart markets. A clear recognition of the roles and responsibilities of regulated and commercial actors is therefore needed to ensure a smooth functioning of the system and market, which facilitates and accelerates the transition towards a sustainable energy system.

There are many small- and medium-sized DSOs in Europe and they have to be able to expand their scope of action. It has been shown in several studies that there are no correlations between company size and efficiency, nor between the number of DSOs operating in a market and the quality of supply. Germany, for instance, has several hundred DSOs and according to figures of

the System Average Interruption Duration Index (SAIDI), has the most reliable grids in Europe.

System management

As elaborated on in the section on current market barriers, DSOs will become more active system managers with increasing complexity of network dynamics at local level. Apart from efficiently exploiting the synergies between their networks – for instance, through P2G and using gas connections for cooling demands – network operators should also be enabled to procure services for grid management from DER in commercial marketplaces. Clear rules for DSOs to purchase system services – as discussed in the Think report by the Florence School of Regulation – will counteract the inherent conflict with other market actors, that is, ESCOs, bidding for the same services and will allow DSOs to fulfil their tasks as neutral market facilitators. For example, transparent auctions overseen by the regulator with detailed protocols of bidding procedures would prevent any abuse of position and guarantee that vertically-integrated DSOs do not give preferential treatment to their own group's retailer.

Data management

The operation of smart grids and smart markets both rely on data about all parties connected to the grid, distributed resources and consumers. It is therefore indisputable that the management of data (consumption patterns, actual loads, generator outputs, congestion) is best made the responsibility of DSOs, for various reasons. First and foremost, DSOs are responsible for grid stability and security of supply. They should not depend on commercial market parties for data availability if security of supply and system integrity is to be guaranteed. In the changing energy system, with growing shares of variable supply sources, fast and smooth data communication to ensure system stability is essential to meet Europe's climate and energy targets.

Second, as non-commercial parties, DSOs will provide data to third parties in a non-discriminatory manner and thereby create a level playing field for all market players. Delivering data will stimulate the entrance of new market actors and enable new business models (aggregators, ESCOs). Finally, and very importantly, as regulated entities, which have no interest in treating data as commercial products, DSOs can be controlled more easily and effectively by regulators than third (commercial) parties. This safeguards the privacy of consumer data.

If an unregulated party became responsible for data handling, it would entail fundamental risks for data privacy and security.

Technological issues and business opportunities

The bulk of smart grid technologies are already used in other applications, such as manufacturing and telecommunications and are being adapted for use in grid operations. In general, smart grid technology can be grouped into seven key areas:

(i) Integrated communications: Some communications are up to date, but are non-uniform because they have been developed in an incremental fashion and not fully integrated. In most cases, data are being collected via modem rather than direct network connection. Areas for improvement include: substation automation, demand response, distribution automation, supervisory control and data acquisition (SCADA), energy management systems, wireless mesh networks and other technologies, power-line carrier communications and fibre-optics. Integrated communications will allow for real-time control, information and data exchange to optimize system reliability, asset utilization and security.

(ii) Sensing and measurement: Core duties include evaluating congestion and grid stability, monitoring equipment health, energy theft prevention and control strategies support. Technologies include: advanced microprocessor meters (smart meter) and meter reading equipment, wide-area monitoring systems, dynamic line rating , electromagnetic signature measurement/analysis, time-of-use and real-time pricing tools, advanced switches and cables, backscatter radio technology, and Digital protective relays.

(iii) Smart meters: A smart grid often replaces analogue mechanical meters with digital meters that record usage in real time. Often, this technology is referred to as advanced metering infrastructure (AMI) because meters are not useful in and of themselves and need to be installed in conjunction with some type of communications infrastructure to get the data back to the utility (wires, fibre optic, WiFi, cellular, or power-line carrier). Advanced Metering Infrastructure may provide a communication path extending from power generation plants, at one end, all the way to end-use electrical consumption in homes and businesses. These end-use consumption devices may include outlets and other smart grid-enabled appliances, such as water heaters, and devices, such as thermostats.

(iv) Phasor measurement units: High speed sensors called phasor measurement units (PMUs) distributed throughout a transmission network can be used to monitor the state of the electric system. PMUs can take measurements at rates of up to 30 times per second, which is much faster than the speed of existing SCADA technologies. Phasors are representations of the magnitude and phase of alternating voltage at a point in the network. In the 1980s, it was realized that the clock pulses from global positioning system (GPS) satellites could provide very precise time signals to devices in the field, allowing measurement of voltage phase angle differences across wide distances. Research suggests that with large numbers of PMUs and the ability to compare voltage phase angles at key points on the grid, automated systems may be able to revolutionize the management of power systems by responding to system conditions in a rapid, dynamic fashion.

(v) Advanced grid components: Innovations in superconductivity, fault tolerance, storage, power electronics and diagnostics components are changing fundamental abilities and characteristics of grids. Technologies within these broad R&D categories include: flexible alternating current transmission/distribution system devices, high voltage direct current, first and second generation superconducting wire, high temperature superconducting cable, distributed energy generation and storage devices, composite conductors and “intelligent” appliances.

(vi) Smart power generation: Smart power generation involves matching electricity production with demand using multiple identical generators that can start, stop and operate efficiently at chosen load, independently of the others, making them suitable for base load and peaking power generation. Matching supply and demand – called load balancing – is essential for a stable and reliable electricity supply. Short-term deviations in the balance lead to frequency variations and a prolonged mismatch results in blackouts. The load balancing task has become much more challenging as increasingly intermittent and variable generators, such as wind turbines and solar cells, are added to the grid, forcing other producers to adapt their output much more frequently than has been required in the past.

(vii) Improved interfaces and decision support: Information systems that reduce complexity so that operators and managers have tools to effectively and efficiently operate a grid with an increasing number of variables. Technologies

include visualization techniques that reduce large quantities of data into easily understood visual formats, software systems that provide multiple options when systems operator actions are required, and simulators for operational training and “what-if” analysis.

Actors and beneficiaries

Users: Users' needs include quality of service and value for money. In the coming years, users' expectations will broaden and will include value added services, energy services on demand and total connectivity. They will be asking for connection of in-house generation, the ability to sell surplus generation back to the grid, real time tariffs and the freedom to choose their suppliers.

Local authorities: As energy systems become decentralized, the local and regional management of resources and utilities becomes desirable and necessary. Local energy companies, public-private partnerships and renewable energy cooperatives will be among the first beneficiaries of the new electricity generation.

Electricity network companies: Network owners and operators are called upon to fulfil customers' expectations in an efficient and cost effective way. They are required to undertake necessary investments to guarantee high levels of power quality and system security, while assuring adequate remuneration for their shareholders. Investment remuneration and stable regulatory frameworks will be necessary for »level playing field« competition in a multi-agent market.

Energy service companies: Companies will have to satisfy the growing needs of users. Some users will seek simple “turnkey” products. Cost efficiencies and savings will need to be made visible, in monetary terms. This must be accompanied by an increase in services delivered and a reduction of intrusion upon the customer, such as for maintenance of the system. In general, a trend will be observed from the present “infrastructure-driven” to progressive “service-driven” paradigms in the European electricity supply industry.

Technology providers: Significant technology and business changes lie ahead and equipment manufacturers will be key players in developing innovative solutions and in achieving their effective deployment by working with the grid

companies. As with grid companies, technology providers will have important investment decisions to make. A shared vision will be critical to ensuring sound strategic developments that provide open access, long-term value and integration with existing infrastructure.

Researchers: The research community has a critical role to play: without research there is no innovation and without innovation there is no development. Cooperation among universities and research centres, utilities, manufacturers, regulators and legislators must be fostered, not only for the successful development of new technologies but also to overcome non-technical barriers.

Producers: Electricity grids are complex, integrated systems and there is a sensitive interaction between generators, grid systems and demand. It will be important for the future to ensure the continuing close involvement of generation companies, which understand the electrical characteristics of their equipment and their operational dynamics.

Regulators: The European market for energy and related services should be supported by a stable and clear regulatory framework, with well-established and harmonized rules across Europe. Regulatory frameworks should have aligned incentives which secure a grid with increasingly open access and a clear investment remuneration system and keep transmission and distribution costs as low as possible. Effective and efficient innovation should be rewarded.

Governmental agencies: Governments and lawmakers will have to prepare new legislation to take into account apparently contradictory goals. Increasing competition is expected to keep a downward pressure on energy prices, but a more environmentally friendly energy mix may bring cost challenges. Legislation will be affected by innovative technologies, the evolution of grid organizations, the requirement for greater flexibility and increased cross-border trading and by the need to ensure economic development, environmental protection, greater competitiveness, job creation and high quality security of supply (both short- and long-term).

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ABBREVIATIONS

AMM	Automated meter management
AMR	Automated meter reading
CEER	Council of European Energy Regulators
DAS	Day- ahead scheduling
DLC	Direct load control
DSM	Demand side management
DSOs	Distribution system operators
EB CCC	Emergency backup central control centre
ECCs	Energy control centres
EDM	Energy data management
EMS	Energy management system
ESCOs	Energy services companies
FERC	Federal Energy Regulatory Commission
GPRS	General packet radio service
HEDNO	Hellenic Electricity Distribution Network Operator
HV	High voltage
LCS	Local control systems
LV	Low voltage
MV	Medium voltage
NII	Non-interconnected islands
NRAs	National regulatory authorities
PLC	Programmable logic controller
PMUs	Phasor measurement units
SCADA	Supervisory control and data acquisition
SLA	Service level Agreement
TCP/IP	Transmission Control Protocol and Internet Protocols

2. STORAGE OF ELECTRICITY - A REVIEW

Summary

Storage systems are required for a gradual increase in variable output RES, but their feasibility has not been proved given the existing regulatory framework. On the other hand, electrical energy storage (EES) in non-interconnected islands is the only way to increase the penetration of RES and reduce their dependence on oil-fuelled power stations.

Batteries with PVs, hybrid hydro and combined oil and RES generators conditionally can be used for increasing penetration in non-interconnected and small island systems. The available options for energy storage and integration of different energy and resource flows that could help to solve intermittency problems in the islands' energy systems have been proposed in many cases or have been implemented.

El Hierro project on the small El Hierro island, Canary Islands, embodies the first major Megawatt-level energy project by linking energy storage systems with wind power generation using water storage delivered by the pumping system between two artificial lakes. The hydroelectric power station constituted by 4 Pelton groups of 2.830 kW of power each, for a total of 11,32MW. The Wind Farm is constituted by a set of 5 wind turbines (Enercon E-70) each with 2,3 MW of power which makes a total power of 11,5 MW. Besides reliable electricity, more fresh water, and improved agricultural opportunities, the partnership expects to earn over \$5 million a year in electricity sales, and save almost \$2.5 million a year in diesel imports. Since the whole project cost about \$93 million, half of which was funded by a European Union government grant, project partners will recoup their investment (50% of the initial cost) relatively quickly (about 10 years). The system, which came online in 2014, frees the island from dependence on expensive imported fuel oil, the bane of many an island grid. Similar projects are being conducted for other islands in the European Union such as, Madeira (Portugal), Crete and Ikaria (Greece).

Efficient management of batteries in smaller island power systems with increased RES penetration can provide (in terms of adequacy in case of disturbance) both

economic and operational benefits for the power systems operators, as shown by studies of the island of Kythnos (Cyclades, Greece), the first hybrid system in Europe based in the combination of wind, PVs, batteries and energy control centre. A very recent project is also under development at the remote island of Tilos (Dodecanese, Greece).

Above all, the main challenge for energy storage development is economic. The economic and business case varies from instance to instance, depending, among other things, on where the storage is needed: generation, transmission, distribution or customer level. The benefits for users/operators are also closely linked to the question of storage location.

Strong support and political will at local, national and international level to apply financial support mechanisms for energy storage systems and thus increase RES penetration is crucial for further development and application of energy storage technologies. Another approach for financing energy storage is through the payment of grid management services. In this case, real costs and benefits of storage are usually hidden and not adequately remunerated. As the EU plans to significantly increase the RES share in the electricity supply of some regions, additional storage capacity is required. Well-structured and transparent FiT has proved to be an effective mechanism for the deployment of RES and if used for energy storage the construction of the necessary new storage capacities can be ensured within a reasonable time.

In recent years, a debate has been running on the need for storage systems in the European power system. In the current decade, several countries will gradually try to achieve a higher share of renewable energy sources (RES) in the grid, mainly from wind energy and photovoltaic integration. Variability of wind and photovoltaic generation and the current structure of the European power system introduce technical constraints that should be taken into consideration in the forthcoming large-scale RES integration. This document provides an overview of the current status of storage, technological and regulation issues, demonstration projects and so on. According to this overview, storage systems are required for a gradual increase in variable output RES, but their feasibility has not been proved given the existing regulatory framework. On the other hand, electrical energy storage (EES) coupled with smart grid applications in non-interconnected islands is the only way to increase the penetration of RES and to reduce their

dependence on oil-fuelled power stations. This is why in this paper islands are examined as particular cases, because the high cost of the first pilot applications discourages private investors from taking the next step.

2.1 Current Status in Europe

Currently, there is limited storage in the EU energy system (around 5 per cent of total installed capacity) almost exclusively from pumped hydro-storage, mainly in mountainous areas (Alps, Pyrenees, Scottish Highlands, Ardennes, Carpathians, Pindos-Greece). Other forms of storage – batteries, electric cars, flywheels, hydrogen and chemical storage – are either minimal or at a very early stage of development.

Energy storage is essential to balance supply and demand. Peaks and troughs in demand can often be anticipated and satisfied by increasing or decreasing generation at fairly short notice. In a low-carbon system, intermittent renewable energy (RES) makes it more difficult to vary output, and rises in demand do not necessarily correspond to rises in RES generation. Higher levels of energy storage are required for grid flexibility and grid stability and to cope with the increasing use of intermittent wind and solar electricity. Smart cities, a key energy policy goal, require smart grids and smart storage.

2.2 Technological Issues / Pumped Hydro Storage Systems

Energy storage is an established technology. Pumped hydro storage systems (PHS) for large-scale electricity storage represent almost 99 per cent of current worldwide storage capacity. Pumped hydro was attractive, and essential, when Europe's networks were composed mainly of a large number of regional grids with very weak interconnections.

Today, modern fossil fuel-based power plants (especially natural gas combined cycles) are becoming more and more flexible. Their ramping -up speed in res-

ponse to rapid changes in demand is increasing. They can provide reliable and flexible back-up power. In a short term, therefore, electricity storage needs to fill the gap between the ramping down time of wind and solar and the ramping up time of these back-up plants. The challenge is to increase existing storage capacities and efficiencies.

The need to promote more energy storage is related to the increase in intermittent wind and solar and to the demand peak increase.

When the intermittent renewable share is lower than 15 to 20 per cent of overall electricity consumption, the grid operators are able to compensate the intermittency. This is not the case when the share exceeds 20–25 per cent, as is reached at times in Denmark, Spain and Germany. When these levels are reached, intermittent RES need to be curtailed during the low consumption periods in order to avoid grid perturbation (frequency, voltage, reactive power) and grid congestion, unless the RES excess can be stored. Alternative resources – back-up and/or storage – are needed when demand does not fall at the same time as the fall in RES generation.

Energy storage needs to be integrated in network-based energy systems, in the electrical grid system, heating and cooling network and gas networks. It can also make an important contribution to the development and emergence of the smart grid concept at all voltage levels.

Energy storage can become an integrated part of combined heat and power (CHP), solar thermal and wind energy systems to facilitate their integration in the grid.

The peak increase issue can also be solved where energy storage is available at different levels of the electrical system: centralized energy storage as a reserve; decentralized storage in the form of demand management and demand response systems. In CHP district networks, the storage of heat (or cold) can be much more cost effective than the storage of electricity, if the CHP system is operated according to electricity demand.

Energy storage can be integrated at different levels of the electricity system:

- Generation level: arbitrage, balancing and reserve power
- Transmission level: frequency control, investment deferral

- Distribution level: voltage control, capacity support
- Customer level: peak shaving, time of use cost management.

These different locations in the power system will involve different stakeholders and will have an impact on the type of services to be provided. Each location will provide a specific share of deregulated and regulated income streams. Different energy storage systems will have to be considered (centralized and decentralized) and specific business models will have to be identified. A localization map will help to define the possible needs for regulatory change and incentives.

It is important to ensure that electricity from RES keeps its RES label, even if it has been stored before final consumption. Possible feed-in tariffs should not be affected by intermediate storage. Only the share of renewables at the point of pumping should qualify as renewable electricity.

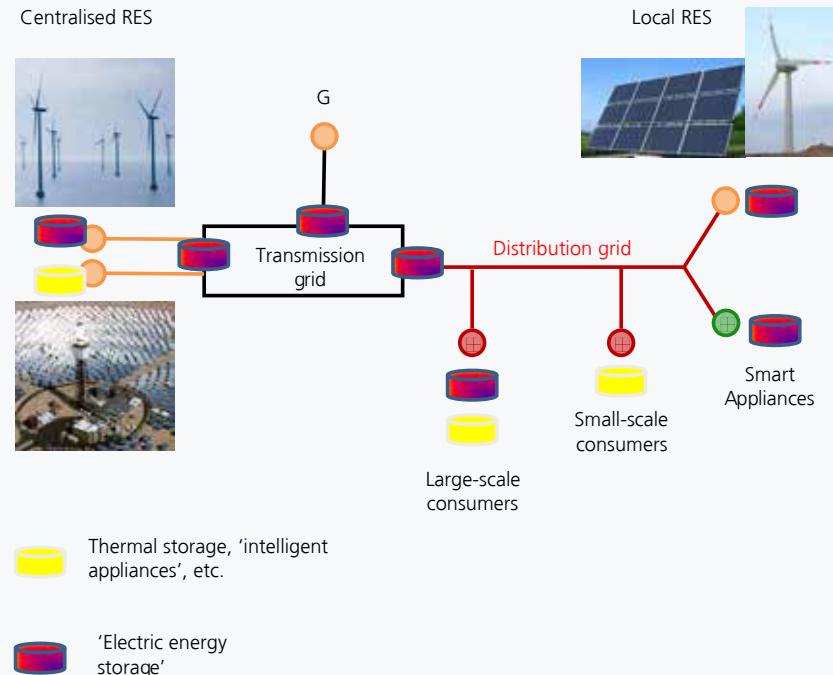


Figure 1: In a future low-carbon energy system, storage will be needed at all points of the electricity system.

Source: European Commission, DG ENER

2.3 Types of Energy Storage

Energy storage technology can serve at various locations at which electricity is produced, transported, consumed and held in reserve (back-up). Depending on the location, storage can be large-scale (GW), medium-sized (MW) or micro, local systems (kW). Research and technological development is needed to enable the wider application of many known technologies and to develop new ones. Some of the key technologies, not all of which are at the stage of commercial application, are:

- Large bulk energy (GW):
 - Thermal storage,
 - Pumped hydro storage;
 - Compressed air energy storage (CAES);- Chemical storage (for example, hydrogen - large-scale >100MW, up to weeks and months).
- Grid storage systems (MW) able to provide:
 - Power: super-capacitors, superconducting magnetic energy storage (SMES), flywheels
 - Energy: batteries such as lead acid , Li-ion, NaS & flow batteries
 - Energy and power: LA & Li-ion batteries
 - Hydrogen energy storage / CAES / pumped hydro energy storage (PHES) (small scale, $10\text{MW} < P < 100\text{MW}$, hours to days).
- End-user storage systems (kW):
 - Power: super-capacitors, flywheels
 - Energy: batteries such as lead acid and Li-ion
 - Energy and power: Li-ion batteries.

Energy storage needs, and patterns of access are changing (for example, not only driven by demand-side variations). Technologies will need to respond accordingly. Storage capacity also depends on the size of the reservoir. This determines the time that this power is available. In the past, with one cycle per day, energy storage was rated mainly in GWh (energy capacity); today the same systems are used up to 10 and 20 times per day; the installed power in GW (given by the number and size of the installed turbines) becomes more important, as the service requested has changed over the years. This dynamic behaviour of existing storage will increasingly move in the direction of quick and powerful response to the needs of the grid.

The main challenges for storage are:

(i) technological: increasing capacities and efficiencies of existing technologies, developing new technologies for local (domestic), decentralized or large centralized application, and market deployment;

(ii) market and regulatory issues: creating appropriate market signals to incentivize the building of storage capacity and provision of storage services, building up a European market and common balancing markets, as exist in Nordic countries and between Germany and Austria;

(iii) strategic: developing a systemic or holistic approach to storage, bridging technical, regulatory, market and political aspects.

Above all, the main challenge for energy storage development is economic. The economic and business case varies from instance to instance, depending, among other things, on where the storage is needed: generation, transmission, distribution or customer level. The benefits for users/operators are also closely linked to the question of storage location.

2.4 The Economics of Storage

The cost of storing electricity per kWh has a very high range of variations according to location, grid characteristics, substitution cost and kind of technology used. Generally speaking, energy storage is economical when the marginal cost of electricity¹ varies more than the costs of storing and retrieving the energy plus the price of energy lost in the process.

However, the marginal cost of electricity varies because of the varying operational and fuel costs of different classes of generators. At one extreme, base load power plants – such as coal-fired power plants and nuclear power plants – are low marginal cost generators, as they have high capital and maintenance costs

¹ This value works by comparing the added system cost of increasing electricity generation from one source versus that from other sources of electricity generation.

but low fuel costs. At the other extreme, peaking power plants such as gas turbine natural gas plants, burn expensive fuel but are cheaper to build, operate and maintain. To minimize the total operational cost of generating power, base load generators are dispatched most of the time, while peak power generators are dispatched only when necessary, generally when energy demand peaks. This is called “economic dispatch”.

Demand for electricity from the world’s various grids varies over the course of the day and from season to season. For the most part, variation in electricity demand is met by varying the amount of electrical energy supplied from primary sources. Increasingly, however, operators are storing lower-cost energy produced at night, then releasing it to the grid during the peak periods of the day when it is more valuable.² In areas with hydroelectric dams, release can be delayed until demand is greater; this form of storage is common and can make use of existing reservoirs. This is not storing “surplus” energy produced elsewhere, but the net effect is the same – although without the efficiency losses. Renewable supplies with variable production, such as wind and solar power, tend to increase the net variation in electric load, increasing the opportunity for grid energy storage.

It may be more economical to find an alternative market for unused electricity, rather than try to store it. High voltage direct current allows for transmission of electricity, losing only 3 per cent per 1,000 km.

Regulatory issues / Feed-in tariffs and storage

Feed-in tariffs (FIT) for various energy storage and desalination systems cannot receive guarantees of origin that will be recognized at the EU level and accepted by the European Commission. Moreover, according to the same EU Directive, electricity used by pumped storage is included in final gross energy consumption, which means that if used, it increases the amount of energy from renewable sources that should be achieved by 2020. On the other hand, all electricity produced from renewable energy sources (directly delivered to the grid or used to pump water uphill or for any other dump load) will be treated in final gross electricity consumption as renewable energy sources without taking into account storage efficiencies. This regulation avoids the twofold counting of RES-E but energy storage is also differentiated as all stored energy is treated as consumption.

2 <http://www.eosenergystorage.com/technology-and-products/>

The introduction of FIT for storages with traceable GO could lead to better system designs and improved efficiencies. Consequently, FIT for storage should only be used in a system where traceable GO exists in order to make sure that the storage is not used to store electricity from conventional power plants and thereby just adding a loss in efficiency if the feed-in tariff for »discharging« the storage is too high.

Batteries with PVs, hybrid hydro and combined oil and RES generators conditionally can be used for increasing penetration in small and non interconnected island systems. The proposed FIT remunerates batteries and inverters as a service and not as an energy flow, also taking into account the potential economic and operational benefits for the power system. The FIT scheme tries to make PV investors, for example, consider storage if they want to increase their production share in the island power system above a level which could lead to power curtailment. Such a scheme would discourage investors from adding PV capacity that will neither be fed into the grid nor bring significant benefits to the power system. The efficiency of the FIT scheme for the same penetration level – around 15 per cent – to make the combination of storage with PV more attractive than simply increasing PV capacity, is the suggested way.

The available options for energy storage and integration of different energy and resource flows that could help to solve intermittency problems in the islands' energy systems have been proposed in many cases or have been implemented, as in El Hierro (Canaria, Spain), or are under final construction, as in Madeira (Portugal), Crete and Ikaria islands in Greece.

Efficient management of batteries in small island power systems with increased RES penetration can provide (in terms of adequacy in case of disturbance) both economic and operational benefits for the power systems operators, as shown by studies of the island of Kythnos (Cyclades-Greece), the first hybrid system in Europe based in the combination of wind, PVs, batteries and energy control center. A very recent project is also under development in the remote island of Tilos (Dodecanese)

Hydrogen has also been proposed as means of storage. Electrolytic H₂ production could be used as a load management method for wind power in weak distribution grids. H₂ production and storage may become a viable option in areas where

reinforcements of existing grids are costly or controversial due to environmental concerns. A similar conclusion is the advantage of the wind–hydrogen system over wind-only systems, due to the fact that energy generation is manageable, hence bringing it closer to demand.

As RES penetration increases in autonomous or weakly inter-connected islands, operators issue instructions for temporarily disconnecting part of RES production. Similar problems will be faced by large power systems as RES penetration reaches certain levels. This excess electricity can be either exploited via heat pumps and thermal energy storage intended for harsh winter climate areas or via ice banks or other cold energy storage systems in regions with cooling needs.

For islands where water scarcity is a reality, desalination can be considered an alternative solution. Subsequently, there are also places where desalination could effectively be applied in combination with renewable energy sources and pumped hydro storage systems.

As the EU strives to reach goals in its energy policy, energy storage could make a great contribution if similarly successful mechanisms were to be used for promoting RES. The feed-in tariff (FIT) for storage and desalination technologies could be also applied in other parts of the world in order to attract investors to interesting solutions.

Strong support and political will at local, national and international level to apply financial support mechanisms for energy storage systems and thus increase RES penetration is crucial for further development and application of energy storage technologies. All results presented correspond to a preliminary investigation of FIT for energy storage with some representative application and extended discussion. They do not represent an integrated framework to be considered but just one possible solution. Another approach for financing energy storage is through the payment of grid management services. In this case, real costs and benefits of storage are usually hidden and not adequately remunerated. As the EU plans to significantly increase the RES share in the electricity supply of some regions, additional storage capacity is required. Well structured and transparent feed-in tariffs have proved to be an effective mechanism and if used for energy storage they can ensure construction of the necessary new storage capacities within a reasonable time.

Storage through hydro / RES hybrid systems

Pumped storage is currently the most mature centralized storage technology, particularly suited for facilitating large-scale RES integration in medium and large power systems, due to its high power and energy capacity. A favourable and realistic way to introduce pumped storage in island systems is based on the concept of HPSs, which are virtual power plants comprising wind farms and storage facilities, operating in a coordinated manner. One of the main challenges in island systems is the possibility to recover, by pumped storage, a significant part of rejected wind energy. In any case, in order to maximize the benefits and fully exploit the potential arising from the introduction of storage, proper sizing of the HPS components is necessary.

There are two alternative perspectives regarding the optimization targets:

- (i)** The investor's perspective, where the objective is to maximize the return of the HPS investment. It is the realistic view in today's electricity markets, where investors act as independent entities seeking maximum profit. From the investor's point of view, applicable energy and capacity tariffs critically influence the optimum sizing of HPS components. Wind potential at the site of the HPS wind farm is crucial for the economic viability of the HPS investment but its effect on HPS optimum sizing is secondary. The investment cost of the HPS components has a moderate effect on its sizing, the wind farm cost being the most important.
- (ii)** The system perspective, setting as optimization targets an increase in RES penetration, along with maintaining the generation cost of the overall system as low as possible. The second perspective constitutes a multi-objective optimization problem and it resembles the traditional approach followed in generation system planning, seeking to minimize the overall generation cost of the system.

A recent study after examining a variety of possible solutions in different Greek islands, concludes that "optimization results from taking a system perspective indicate that the integration of a relatively small and properly sized HPS may lead to a reduction of the island system levelized cost of energy (LCOE) and at the same time increase of RES penetration, even in island systems characterized by low thermal generation costs (Heave Fuel

Oil-HFO). However, higher RES penetration levels come for substantially larger HPSs, leading to an increase in the system's LCOE. On the other hand, in island systems with high generating cost (Light Fuel Oil-LFO), the RES penetration increase due to HPS integration is combined with a reduction of the LCOE."

Regulatory framework of hybrid systems for Greek islands

According to Greek law 3468/2006 a hybrid system is defined as a combination of renewable energy production units with some kind of energy storage and control of energy recovery. In addition, the law allows the transformation of existing RES installations to include storage facilities. Furthermore, these installations are not necessary for spatial coherence as the produced energy (electricity) can be infused into the grid. In this sense, the grid could be considered an upper level storage system. In the existing regulatory framework, the stored energy can be retrieved on a priority basis, in hours with peak loads through the HS's units of controlled energy production. RES integration into the grid is also a priority and offers the possibility of a triple pricing scheme: from RES directly infused into the grid, from storage units that cover demand peaks and RES non-availability and finally from so-called »guarantied power«. The second and third price components are subject to negotiation with the grid operator and their calculation takes into account the avoided energy cost from conventional units. Within the Greek system for non-interconnected islands there is an obligation for day-based energy planning and an intra-day revision within the framework of 12 hours. The owner of the HS (producer) submits its energy offer on a 24 or 12 hour basis in accordance with the demand of the grid operator, the load following power capacity.

2.5 Barriers to Energy Storage

The development and deployment of energy storage technologies in order to exploit their strategic advantages and many potential benefits, but not at the expense of creating distorted and unfair energy markets, is a great challenge for the development of future electricity grid infrastructure.

Energy storage can also contribute to the solution of peak demand increases, either with centralized schemes as reserve or with decentralized demand management and response systems.

As with the integration of any novel technology, the deployment of energy storage systems faces many barriers, the most significant of which is cost-competitiveness. Directly linked to this barrier is the challenge of regulatory uncertainty surrounding grid-scale energy storage deployment. Many of the regulatory issues trace back to the present structure of the electric power industry. Energy storage participates limitedly on the electric power system, serving needs that are very narrow, engaging in only one energy market. Potential roles of energy storage in the power grid are not clearly defined, there is no standard system for assigning value to energy storage services and there are dissenting opinions on allowing single energy storage systems to participate in multiple energy markets.

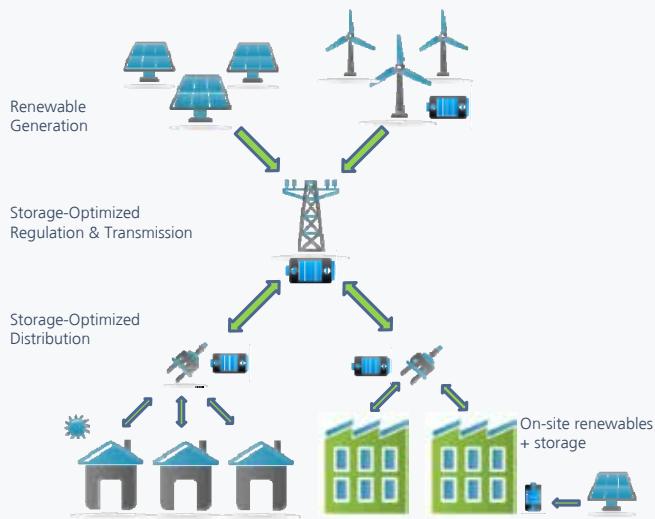


Figure 2: Future electricity grid infrastructure and possible role of energy storage at various levels.

Source: European Commission, DG ENER

The following list summarizes and briefly presents the possible obstacles or barriers that can be encountered in an electricity system with regard to deployment and further development of electrical energy storage.

Lack of clear official definition of storage: There are now a substantial number of independent reports which support the view that energy storage is a key technology, a vital part of our future electrical infrastructure and part of the solution of future system balancing. However, a clear official definition is required at EU level in order to be integrated in the corresponding regulatory framework of member states. (in Greece for example, the future energy storage is associated mainly with the recovery of RES rejected production in conditions of a high RES share).

Lack of definitive storage needs: A first key question is whether and at what level grid-scale energy storage is needed. Estimations so far differ considerably, depending on the particular grid and future electricity plans. Results range from a wide range of potential needs to a lack of such information on energy storage needs. Definitive determination of these needs in a specific electricity system is a great challenge but necessary for any further step.

Lack of definitive storage role and integration level: In future low-carbon energy systems there will be multiple possible roles for energy storage, and at different levels of the electricity grid: (i) at generation level as balancing, reserve and so on; (ii) at transmission level for frequency control and/or investment deferral; (iii) at distribution level for voltage control, capacity support and so on; and (iv) at customer level, for peak saving, cost management and so on.

Lack of awareness of energy storage benefits: Many policy-makers, grid operators and the general public are unaware of what energy storage is; the specific technologies that comprise energy storage; recent technological advancements; data about its effectiveness; and what benefits energy storage can provide. Therefore, effective and timely planning of energy storage deployment may be obstructed. This can cause substantial delays in the development of the overall electricity system in response to the plan for a high RES share because the time period from initial design to commissioning of a grid-scale storage plant – for example, pumped hydro energy storage – may exceed 10 years.

Conservative industry culture: Power plants owners are reluctant to invest in new technologies such as energy storage if they are unsure whether they will be able to recover their capital costs. Regulatory uncertainty hinders economic investment in energy storage even more. Conventional generation options,

including flexible natural gas-fired turbines, continue to be the primary option for load following, peak power generation and ancillary services. Market uncertainty, combined with a lack of incentives for risk-taking in regulated utilities, discourages the deployment of technologies that are new or have long lead times.

Public opposition and environmental concerns: PHS development on existing streams can affect water quality and ecosystems, as with any other hydropower project. Moreover, energy storage scheme design and operation is more complex than most other production units, because it combines energy consumption and production, even at the same time. This may cause increased concern or opposition among local communities in relation to possible negative effects on the environment and water resources. Sometimes these concerns are reasonable. Nevertheless, open-cycle plants have more environmental impact (and potential opposition) and hence higher investor risks. Public opposition can significantly delay the licensing procedure and in some cases has prevented realization of large hydropower projects.

Lack of cohesive and definitive regulatory and legislative framework at EU level:

Regulatory uncertainty does not allow potential investors to determine the returns on such investments. A detailed and cohesive regulatory framework is required at national level, covering all aspects of energy storage usage and complying with the corresponding EU legislation and Internal Electricity Market, which are still under development. Important issues and uncertainties still exist – for example, the provision of ancillary services in the interconnected system across national borders – and need to be resolved. Consequently, the construction of a thorough and long-standing regulatory and legislative framework at national level is not yet feasible.

Unclear potential ownership: Critical questions arise concerning the ownership and management of electrical energy storage. Should storage be owned only by utilities or could transmission system operators (TSOs) also participate in this market? A definitive answer cannot be extracted from the latest EU Electricity Directive, and the situation is also unclear at national level. The existing regulatory framework for energy storage (if any) treats electrical energy storage as a type of electricity generation technology rather than as an investment in transmission capacity. Thus, transmission and distribution companies are barred from owning electrical energy storage. However, TSOs may have an interest in

the energy storage market not only to improve their services but also with regard to the extent to which market outcomes rely on new investment in transmission lines. But abusive market behaviour might be unavoidable if a TSO controls both generation and energy storage units. On the other hand, the optimal technical, economic and social performance of a particular grid system may allow some kind of energy storage control by TSOs at specific locations. Multi-market participation is presently not permitted by energy market regulations, as grid assets only fall under one asset category (generation, transmission, distribution) and thus can only draw from a single revenue stream.

Lack of cost-effective and efficient transmission planning: Energy storage facilities provide ancillary services to the grid that help it run more efficiently and can avert the need for new transmission lines and power plants. These benefits may translate into cost savings for utilities and ratepayers. However, utilities and policy-makers lack methodologies to quantify these savings. As a result, the current regulatory structure discourages them from considering energy storage as an alternative to building new transmission lines and power plants that may be more costly than comparable energy storage facilities. It is also unclear what entity will take on the costs of storage provided to the grid. This can depend on regulations that are to be developed, but also on transmission planning decisions, which still are to be made. Transmission planning will influence the jurisdiction in which energy storage facilities may fall. Two possible ways in which energy storage can be incorporated for the purposes of increasing the value of wind energy include: storage of surplus RES production, or hybrid RES storage with the ability to buy from the grid during low-value time periods (off-peak). This also depends on transmission planning decisions.

High capital costs of storage units: The capital costs of EES technologies are high compared with natural gas units (except some pumped hydro schemes), which can provide several similar services. An element of this cost is the long construction time and associated uncertainty and risks, under continuously changing market conditions and technology. For the new, less mature technologies this is either because they have not yet reached cost parity with other market (generation/demand) resources or transmission/ distribution assets, or economies of scale have not yet been achieved because of low market penetration. Also, due to the above reasons, access to financial support for large electricity storage plants is difficult. Moreover, the economic environment and financial

factors in several European countries, such as Greece, remain negative, hence obstructing large investments in the electricity sector.

Lack of adequate valuation of energy storage services and benefits: Although the net social benefits of large storage plants are positive, the benefits are distributed among power producers, system operators, distribution companies, end-users and society at large. The decision to build a plant, however, must be made by a single entity, and it is often unclear how that entity can capture enough benefit to justify the investment. Assessment of energy storage value is very difficult, due to several uncertainties: because energy storage could potentially provide transmission, distribution and generation services, it is possible to recover costs under both cost-based and market-based rates. But no clear way exists to fit energy storage into the existing regulatory and cost recovery structure. The benefits for users/operators are closely linked to the question of storage location in the system (generation, transmission, distribution). Energy storage studies in Europe indicate that the provision of a single service – for example, reserve – will be not sufficient for a viable storage scheme. There are still several widely acknowledged benefits and value streams associated with bulk storage for which cost recovery/financial return is elusive under current policy and electricity market mechanisms. But there is no regulation in place that would allow energy storage facilities to recover costs from providing multiple kinds of services to the grid, which would greatly increase the economic argument behind the incorporation of energy storage. Unfortunately, the holistic costs for grid balancing – many of which are not routinely quantified by utilities, or which impose externalities (emissions penalties, reliability impacts and so on, which do not show up in costs) – are neither transparent nor known with any degree of precision on a real-time basis. Therefore, better ways of providing the balancing service, such as with bulk energy storage, are difficult to evaluate properly. Wholesale electricity markets also do not capture all the potential benefits of storage to the electric distribution system, including deferral of new equipment and reduced power line losses.

Lack of investment motivations and incentives: The uncertainties surrounding energy storage regulation do not provide any motivation for future investments. Most renewable portfolio standards or government investment or production incentives are written for renewable generation only and exclude energy storage. The capacity credit mechanism is designed for peak generation

units but does not recognize the contribution of other flexible means, such as energy storage. Moreover, no incentives are given for energy storage in recognition of its important contribution to enable higher penetration of variable RES production in the grid. On the contrary, such incentives are, for that reason, provided to both RES power plants and transmission infrastructure (for example, feed-in-tariffs, subsidies and so on).

The above possible implementations involve different stakeholders and may have different impacts on the grid services to be provided and on the corresponding income streams.

In any case, electrical energy storage will certainly compete and/or complement other methods and technologies to improve grid flexibility. Hence, reaching a consensus for the role of energy storage and integration priorities in a particular grid system is a major challenge.

2.6 Technological Challenges

Model creation for future electricity systems design and operation: Modelling future electricity systems of high intermittent RES penetration, low base load production and substantial energy storage incorporation, is a very demanding task.

Current modelling has to be improved in order to quantify the full value of energy storage. It is difficult in part due to the limited ability to simulate realistic power plant and storage system operations over multiple time scales. In addition, there are several uncertainties and unpredictable variables in the future electricity grid system, including structural and financial aspects (for example, RES technology blending, type and flexibility of remaining thermal units, fossil fuel prices, CO₂ emissions framework and so on). The incorporation of other potential means to store energy and/or increase flexibility, such as hydrogen production, demand management and electric vehicle batteries (charging and V2G), is also required for a more elaborate modelling of the future grid and energy storage participation.

On the other hand, there are no methodologies for simulating the various economic benefits associated with enabling renewable energy sources at various

grid levels. For example, no cost effectiveness methodology exists for storage as an alternative to investment in new or upgrade transmission or distribution networks, or as a mean to defer such needs. Also, if intermittent RES production increases regulation service requirements, then it also increases market opportunities for storage. However, there are various potential synergies between intermittent RES and storage that need to be modelled.

The planned interconnection of the large Greek islands with the mainland system is one such example that needs to be thoroughly studied, because interconnection will definitely affect needs, roles and potential benefits, and in turn the optimum sizing of hybrid RES-PHES power plants that can be installed in the islands.

Demonstration plants: New EES technologies such as CAES require a few large-scale demonstration projects to verify their technological maturity and economic feasibility before utility managers will have the confidence to invest in them. However, even for the mature PHES technology, the operation and financial outcomes of conventional pumped storage units in a future environment with very high share of variable RES production are uncertain and also need to be investigated and proven by some pilot plants.

Some pilot energy storage schemes in smaller, autonomous grids are being constructed (Ikaria, Greece), or have reached the commissioning stage (El Hierro, Spain), but real operational data are still missing.

2.7 Annex: Case Studies

Gracioca Island (Azores)

Gracioca Island, part of the Azores Archipelago, hosts 4,500 inhabitants. The RES integration project involved 9 MW wind, 1 MW PV and 3 MW/18 MWh NaS, sodium-sulphur, batteries. The main goal is to reach 100 per cent RES generation during the majority of the year and more than 75 per cent of total annual consumption supplied by RES. The project involves the German Younicos company in collaboration with the local utility EDA. Younicos have established a test laboratory in Berlin simulating energy supply in Graciosa (30 per cent of actual size) in order to study the operation and stability of the new RES system on the island. The project remuneration will not be based on a feed-in-tariff mechanism but on the avoided fuel cost model.

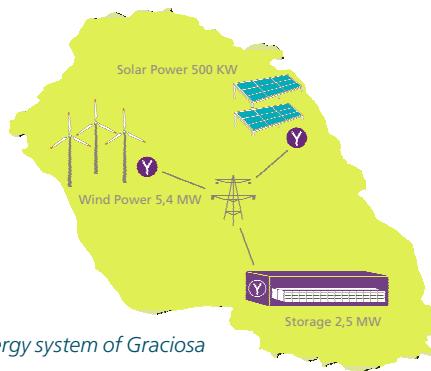


Figure 3: New energy system of Graciosa

Source: UNICOS

The Swiss battery manufacturer Leclanché has received an order from Younicos AG to build a turnkey battery power plant on the Azores island of Graciosa. The storage system is part of a micro-grid solution, which will increase the proportion of renewable energies used on the island from 15 to 65 per cent annually.

The contract for turnkey delivery and commissioning of the battery power plant, which is part of the project being managed by Younicos, is worth approximately € 8.5 million. The first part of the battery storage system, worth € 4 million, is scheduled for delivery later this year. The power storage system consists of batteries with lithium-ion titanate cells, which also have an integrated inverter. In

In addition to delivery, Leclanché will be responsible for the entire engineering, procurement and construction (EPC) process.

The batteries for the project on Graciosa have a total capacity of 3.2 MWh. Leclanché will be using a large proportion of its production capacity to manufacture lithium-ion titanate battery cells in the second half of 2015. The power plant will rely on a combination of different energy sources: a wind farm with 4.5 MW and a solar park with 1 MW capacity. When the power plant goes into operation, the proportion of renewables in annual energy consumption on Graciosa will rise from 15 to 65 per cent.

El Hierro hydro-wind power plant (Canaries, Spain)

A study of the recently implemented electricity production system on El Hierro island can be seen as a model for other similar sized insular systems in which the only endogenous energy is obtained from renewable sources.

El Hierro is the smallest island of the Canaries and like the other islands it relies significantly on diesel consumption – an external source of energy – and features almost no diversification. Its population was 10,995 in 2011.

El Hierro is a singular case among the rest of the islands. Being remotely located and using only diesel fuel, makes local energy system exploitation the most expensive per capita in the Canary Islands.

However, the island has plenty of natural resources such as wind and sun which could be explored. To increase the penetration of intermittent energy sources in insular systems towards a 100 per cent sustainable energy system, an ambitious project was started in 2004 to convert El Hierro to the world's first insular hybrid hydro-wind electricity generation system.

The hydro-wind power plant integrates a wind farm along with a pumped-storage hydroelectric power station. Wind power will directly supply El Hierro's

demand in times of high wind energy production and indirectly during the rest of the time, through the discharge of water stored in an upper reservoir, which has previously been pumped from a lower reservoir when the produced wind energy was in surplus. The water storage delivered by the pumping system converts originally intermittent wind power generation into manageable energy, which is not only a better use of wind energy, but also offers better manageability and greater stability for the power system as a whole.

Technical characteristics

Currently, the configuration of the El Hierro hydro-wind project is made up of the following elements:

- *Top deposit: Located at the La Caldera crater and with a maximum capacity of 380,000 m³ and two drain intakes with PVC-sheet waterproofing. It is repairable underwater.*
- *Bottom deposit: Located in same area as the diesel power plant Llanos Blancos and will have a useful capacity of 150,000 m³ made up of a dam built for this purpose with loose materials such as PVC-sheet waterproofing. It will also be repairable underwater.*
- *Forced conductions were also built, formed by two aerial pipes with a 530 m stretch under a thistle area in the gallery of 0.8 m diameter and 3015 m discharge conduction, with 1 m diameter and 2,350 m turbine capacity conduction and a 1 m and 188 m aspiration conduction.*
- *The pumping plant is installed in a newly-constructed building. It comprises two 1500 kW pump sets and 6 500 kW pump sets with a total power of 6 MW and it also has 1500/500 kW variators.*
- *The turbine capacity plant is made up of 4 Pelton groups of 2,830 kW of power each, for a total power of 11.32 MW and the maximum flow during generation is 2.0m³/s with a gross head of 655 metres.*
- *The wind farm comprises a set of five aerogenerators (Enercon E-70) each with 2.3 MW of power which makes total power of 11.5 MW.*

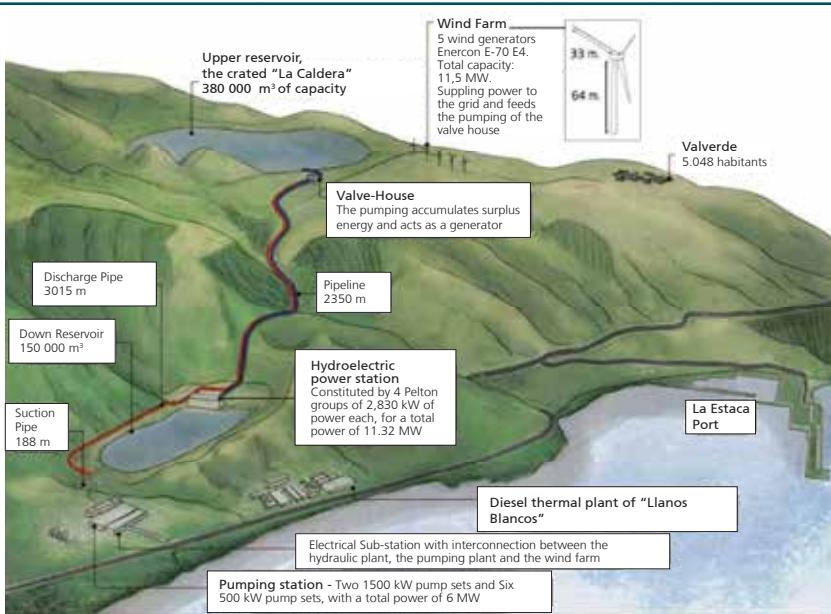


Figure 4: Basic configuration of the hydro-wind power plant

Source: International Renewable Energies and Power Quality Journal, No. 13, April 2014

In order to maximize renewable penetration in the island pumping is not performed with electrical energy originating from the thermal power plant but with the energy from the wind farm instead. Therefore, diesel technology will be used to meet demand only when the hydro-wind electricity generation system is insufficient. This involves establishing a merit order in which wind generation comes first, then pumped hydroelectric generation (discharge) and finally conventional generation (diesel).

Economic data

The hydro-wind power plant's economic life is 65 years, but part of the wind farm equipment and mechanical and electrical systems of turbines and pumps have to be replaced repeatedly after 20, 25 and 30 years, respectively, in order to ensure continued operation during the useful life of the construction.

Therefore, the time horizon of profitability has been calculated as 20 years, which will require a review of the hydro-wind power plant's remuneration after this period of time, taking into consideration sequential replacements of the wind farm, the mechanical pumping equipment, discharge and the rest of the electrical equipment, and ensuring

the recovery of the unamortized portion of investments by the end of its economic life. Thus additional investments have to be made to renew the wind power plant over the hybrid cycle life-period. For the first two decades renewable energy sources contribute more than 75 per cent of power needs. However, since increased pressure on demand is expected due to population growth (estimated annual growth rate of 2 per cent), the incorporation of new renewable generation facilities in the future is expected to maintain or increase the renewable quota.

Finally, according to the official sources of the project (Endesa, ITC) the total cost of the project is estimated at around 80 million euros; that is, double the initial estimations and too high compared with conventional and/or some renewable grid-connected energy sources. This poses questions about the economic sustainability of such projects in the future and the involvement of the private sector without national or European subsidies. On the other hand, Feed In Tariff (FIT) systems for electricity storage, especially for those replacing diesel generators in non-connected islands, have to be reconsidered.

The island of Pellworm

The isle of Pellworm is situated in the World Heritage National Park Wadden Sea (Germany). The area of the island is 37.44 km², the population ca. 1100 and households ca. 720. It belongs to the District of Nordfriesland. Its economy is based on tourism (ca. 2000 beds) and agriculture (ca. 50 Farmers).

Pellworm has a long tradition of decentralized energy supply:

- Solar power plant (1983)
- Hybrid power plant (1989)
- Civic wind park (1989)
- Expo-energy concept (2000)
- Biogas plant (2002)
- Innovation hybrid power plant (2005)
- Innovation study Pellworm (2011).

Identifying the implementation potential of smart grids on the island of Pellworm was the main objective of the innovation study. Therefore not only the technical conditions (power requirements and generation, constraints, options

for energy storage) were analysed, but also the acceptance of the citizens and technological components available on the market were scrutinized. The results showed that a combination of central energy storage and a more flexible load management could reduce energy procurement from the mainland by up to 90 per cent. Selection criteria for storage elements were output, power, charging and discharging time, level of efficiency, availability in the market, environmental compatibility, cost and social acceptance.

Motivation and challenges

- Maintaining the usual supply reliability and quality
- Considering the special characteristics of Schleswig-Holstein: a high percentage of renewables due to consumption; market participants (power generators, municipalities, aggregator, grid operators, energy suppliers and consumers) that have been involved for many years; and a variety of activities concerning smart grids
- Continued expansion of renewable energy plants, supplementing it with additional storage and controllable loads
- Replacement of previous feed-in management through intelligent supply, storage and load management
- Replacement of rigid power pricing models through market-oriented, time-variable and flexible models
- Replacement of existing organizational structures through new organizations.

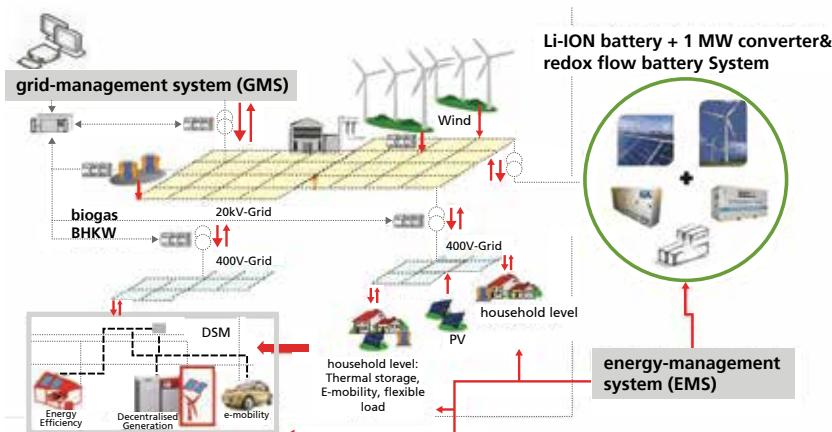


Figure 5: Grid structure with storage elements

Source: www.iosb-ast.fraunhofer.de

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ABBREVIATIONS

EES	Electric energy storage
PHS	Pumped hydro storage
CHP	Combined heat and power
TSO	Transmission system operator
CAES	Compressed air energy storage
HPS	Hybrid power station
WF	Wind farm
HFO	Heavy fuel oil
LCOE	Levelized cost of energy
LFO	Light fuel oil

3. ENERGY EFFICIENT STREET LIGHTING

Summary

In general, local or regional governments as street owners have a legal duty to ensure road safety and must ensure that their lighting systems comply with various technical norms and standards (including a number of EU directives). Therefore, the imperative for compliance with current and forthcoming legislation within the lighting sector at the European level represents a key incentive for local and regional authorities to renew their lighting stock.

A European Parliament and Council Directive on this issue (2009/125/EC), outlines eco-design requirements for energy-using products, focusing on energy consumption during the entire product lifecycle, including production, transport, scrapping and recycling. One aspect of the directive is the phasing-out of high-pressure mercury lamps (HPM) by 2015 and of medium efficient metal halide lamps by 2017. Recently, after the publication of the revision of the European Standard EN13201 (December 2014) it is estimated that adaptive lighting and the use of dimmable lighting systems could reduce energy consumption by 50%. Older technologies do not match the capabilities of LED and other more advanced options. In the case of incandescent bulbs, 90% of the energy consumed goes into producing heat and only 10% goes into light. In contrast to a conventional 100W incandescent light bulb, which generates visible light at around 13 lumens per Watt, compact fluorescent light bulbs (CFL) can generate 60 to 75 lumens per Watt and LED chips more than 100 lumens per Watt.

LED chips, which use light-emitting diodes as a light source, capitalize on the scientific breakthroughs associated with semiconductor technology. LED lights have two key benefits: energy efficiency and long service life, which – at around 50,000 hours – is three to five times longer than conventional lighting technology. From a lifecycle perspective, the majority of costs related to conventional street lighting stem not from the investment itself, but from post-installation costs (energy, maintenance and upkeep costs). As a longer expected service life means considerable reductions in maintenance costs, LEDs' higher upfront costs can become more economic than those of typical fluorescent lights in roughly six years.

Intelligent control systems create additional savings potential as the street lighting level can be reduced in line with requirements, thereby providing further substantial energy savings. Existing legacy systems are far less flexible and dimming level is restricted by up to 50%. LED lights, in contrast, can be controlled with high precision, dimmed rapidly and adjusted continuously to create the level of visibility and sense of safety required.

Energy efficiency upgrades to current street lighting systems are among the most cost-effective and practical energy efficiency measures in the EU. They create long-term cost savings and can be effectively executed by energy services companies (ESCOs) through energy performance contracts (EPC). Such arrangements enable the public sector to transfer the design, implementation and maintenance risk associated with the newer lighting technology to the ESCO and to benefit from its know-how and capabilities. Nevertheless, the complexity of the structure – involving companies, local authorities, utilities and banks – makes the task difficult, especially in countries with little or no experience, as in the case of Greece. Additionally, in many islands, the lack of data on energy consumption by end-users and the mixture of a variety of lighting systems and procurement processes leads to long project development periods.

Energy efficiency (EE) is at the heart of the EU's transition to a resource-efficient economy and the realization of its 2020 strategy for smart, sustainable and inclusive growth. This includes three complementary energy and climate headline targets to be achieved by 2020: to lower greenhouse gas emissions by 20 per cent relative to 1990, to generate 20 per cent of primary energy from renewable sources and to achieve 20 per cent primary energy savings relative to the 2007 projections for 2020. One key area for investment in energy efficiency is street lighting, where there are not only major opportunities to significantly reduce electricity consumption, but also additional benefits associated with phasing out environmentally harmful technologies, reducing maintenance costs and achieving much better overall control of the street lighting environment.

3.1 Why Public / Street Lighting?

Public (street) lighting is a key service provided by public authorities at the local and municipal levels. Good lighting is essential for road safety, personal safety and urban ambience. Street lighting ensures visibility in the dark for motorists, cyclists and pedestrians, thereby reducing road accidents. Street lighting also indirectly facilitates crime prevention by increasing the sense of personal safety, as well as the security of adjacent public and private properties. Street lighting effects can also boost the appeal of cities, towns and communities as commercial and cultural centres by highlighting attractive local landmarks or accentuating the atmosphere during important public events.

However, many street lighting facilities are outdated and therefore highly inefficient. This leads to higher energy requirements and levels of maintenance. For a number of municipalities that have outdated systems, street lighting can account for as much as 30–50 per cent of their entire power consumption.

Financial drivers for energy efficient street lighting

With rising energy prices, energy efficient street lighting is becoming a progressively more attractive proposition, which also contributes to the security of energy supply and tackling climate change. The financial savings from efficient street lighting are based on the underlying technology and the related reduction of energy used and maintenance costs, relative to older street lighting models. The majority of costs stem from the operation of the lighting system and not from the investment itself. The total cost of a typical street lighting installation over a period of 25 years is split approximately as follows: 85 per cent maintenance/operation (including power supply) and 15 per cent capital cost.

According to estimates made by Philips, Europe could save EUR 3 billion in energy costs per year by switching from old to new street lighting technology. The energy saving is equivalent to 45 million barrels of oil equivalent or 11 million tonnes of emitted CO₂. The report has estimated that a city of one million inhabitants, which contracts the supply and maintenance of LED street lighting to a third party (for example, an ESCO, see below), could generate energy savings of around 22 per cent, which at average rates would save such a city about EUR 2.3 million annually.

Legislative drivers for energy efficient lighting

In general, local or regional governments as street owners have a legal duty to ensure road safety and must ensure that their lighting systems comply with various technical norms and standards (including a number of EU directives). Therefore, the imperative for compliance with current and forthcoming legislation within the lighting sector at the European level represents a key incentive for municipalities to renew their lighting stock.

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Technological drivers for energy efficient lighting

The potential for energy efficient improvements to street lighting in Europe is substantial, given that there are about 56 million street lights in Europe, of which around 18 million run at a 1930s standard. With advances in available technology it is now possible to realize energy savings on the scale of 30–50 per cent.

Older technologies do not match the capabilities of LED and other more advanced options. In the case of incandescent bulbs, 90 per cent of the energy consumed goes into producing heat and only 10 per cent goes into light. In contrast to a conventional 100-watt incandescent light bulb, which generates visible light at around 13 lumens per watt, compact fluorescent light bulbs (CFL) can generate 60 to 75 lumens per watt and LED chips more than 100 lumens per watt.

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Intelligent control systems create additional savings potential as the street lighting level can be reduced in line with requirements, thereby providing further substantial energy savings. Existing legacy systems are far less flexible and dimming level is restricted by up to 50 per cent. LED lights, in contrast, can be controlled with high precision, dimmed rapidly and adjusted continuously to create the level of visibility and sense of safety required.

Photo electric cells

Because of their low cost and reliability, photo electric cells have become the accepted means of controlling modern street lighting systems, resulting in almost universal all-night operation. The actual settings of photo electric cells should be carefully considered. Currently, it is almost standard to fit photo electric cells that switch on at 70 lux and off at 35 lux. These settings having been established to mimic those of time switches, to allow for the wide tolerances and inaccuracies of early photo cells and to take account of the time required for discharge lamps to reach their maximum output. Modern discharge lamps, especially those operated on electronic control gear, have a quicker run up period than older lamp types operated on conventional electro magnetic control gear and therefore reach full output quicker. The combination of these factors, together with the fact that most lighting on traffic routes averages 20 lux and on residential streets 7.5 lux, allows the switching levels of photo electric cells to be reconsidered. It is estimated that if the switching levels were reduced to 35 lux on and 16 lux off a saving of 50 hours per annum (approximately 1–2 per cent) could be achieved. This reduction in the operational hours of the lamp would also reduce the chances of premature failure of the lamps towards the end of their life. On an average group replacement period of four years the lamps would have operated 200 hours less (approximately one month's operation) than lamps switching at 70 lux on, 35 lux off. The use of lower switch on/off lighting levels is not recommended for older lamp types such as low pressure sodium lamps

(SOX) and mercury vapour lamps (MBF) operated on conventional electro magnetic control gear. Such installations should be operated at 70 lux on and 35 lux off as a minimum to allow the lamps to fully run up by the time the lighting is required. In some locations it may be possible to consider reducing the hours of operation by switching off when there is little need for lighting. This could be achieved by the use of electronic time switches or similar controllers. However, many people living in rural locations still like and find comfort from street lighting and the value to the emergency services is probably greater than in towns and cities. The light output of many modern lamps can be reduced (dimmed) and this may offer an acceptable alternative to switching off for part of the night. Regarding LED luminaires the cost of the dimming unit is reasonable. In any case it is recommended that when considering the reduction of lighting levels by dimming that the authority still complies with the requirements of national and/or European standards and reduces lighting levels by one or more lighting classes and not just by an arbitrary percentage.

Environmental drivers for energy efficient lighting

According to the European Commission, energy savings from more effective street and office lighting for the period 2009–2020 could be in the magnitude of 38 TWh. Mandating LED lighting for traffic signals and street lights could significantly contribute to the EU's 20-20-20 strategy, if EU governments were to pursue such measures. A McKinsey study suggests that switching from incandescent lights to LED can yield a profit from CO₂ abatement of approximately EUR 140 per tonne of carbon emissions abated, due to LED's energy-saving potential. For example, if Germany were to fund LED retrofits at the same level as solar subsidies (approximately EUR 2.4 billion for 2010/2011), the country could abate 50 megatonnes of carbon due to the resultant drop in prices of the technology and higher penetration (a tenfold saving over what solar subsidies had been projected to deliver).

3.2 Street Lighting and ESCOs

Energy efficiency upgrades to current street lighting systems are among the most cost-effective and practical energy efficiency measures in the EU. They create long-term cost savings and can be effectively executed by energy services companies (ESCos) and energy performance contracting (EPC). Such arrangements enable the public sector to transfer the design, implementation and maintenance risk associated with the newer lighting technology to the ESCO and to benefit from its know-how and capabilities. Nevertheless, the complexity of the structure – involving companies, local authorities, utilities and banks – makes the task difficult, especially in countries with little or no experience, as in the case of Greece. Additionally, in many islands, the lack of data on energy consumption by end-users and the mixture of a variety of lighting systems and procurement processes mean that project development is too long.

The relative success of ESCOs in Germany is due to several factors, but is primarily linked to political decisions and supportive measures taken by the government. The German government has set up regulation that benefits German ESCOs. The most obvious and also the simplest example is the increase of energy prices since 1999 by increasing energy taxes. This regulation has made ESCOs' energy efficiency projects much more economically sound.

Besides regulation, the German government has helped to send a clear starting signal to ESCOs. The Energy Savings Partnership project in Berlin was this starting signal and created demand for ESCOs, which could be perceived in the whole Federal Republic. The implementation of a large number of municipal projects along with public-private partnerships also had a strong demonstration effect by introducing the ESCO into EPC concepts on the market. It was important that this signal was sent out by the demand side: the ESCOs should be able to 'smell' projects with a comparatively high potential. The success of German ESCOs has shown that demonstration projects in the public sector, such as the Berlin Energy Savings Partnership's bundling of buildings, can be crucial to raise awareness and increase trust in EPC among potential customers. The Berlin Energy Agency also established standardization by model contract and measurement and verification procedures. The German government makes financing easier by its public banking group Kreditanstalt für Wiederaufbau (KfW). The KfW raises funds from the financial markets and transfers this capital, via commercial banks, to pro-

gramme applicants in the form of lower interest loans. The German ESCO sector itself has created an important success factor by establishing ESCO associations. The two existing ESCO associations provide information to their members and technical support. They also engage in political lobbying and provide education and information about ESCO business and services to potential ESCO clients. Germany's successful development of the market might also be the result of the existence of a large number of competing energy service providers, such as municipal utilities, manufacturers of building automation and control systems and independent players, such as energy agencies.

Small and large local companies, including former municipal utilities and multinational companies, are active on the market. Furthermore, the four largest energy companies all have daughter companies carrying out various contracting activities, of which one is particularly active in the energy performance business. EPC is a core product of several companies or an expedient supplement to their service portfolio.

Regional project hot-spots can be found in Baden-Württemberg, Bavaria, Berlin and Hessen. These hot-spots have a role-model effect on surrounding regions.

3.3 Case Study 1: Street Lighting in five Greek Islands

Following approval by EIB, the feasibility study for the renovation of street lighting systems started in September 2013. A working group was set up to prepare the specifications for a consultant that would undertake the technical studies for the energy upgrade of the five systems. The subcontract was awarded on 27 January 2014 to the Institute of Communications and Computer Systems of the National Technical University of Athens.

The technical study regarding the energy saving potentials of the municipal street lighting networks in the five islands resulted in the formulation of specific project proposals for each one of them. Based on the technical and economical characteristics of the islands' networks, different project scenarios were proposed, also reflecting different bankability terms. The study was divided into several

steps, followed by respective deliverables, in order to ensure the good quality and consistency of the work.

As a starting point the current state of the street lighting networks had to be analysed, combining field work, measurements, data collection from the municipal databases, data inquiry from the DSO, interviews with local municipal technical personnel and so on. It was a rather demanding process, but resulted in a good knowledge of the current street lighting technologies, geographical distribution, controls, lighting levels, energy consumption and operational costs. The information describing the current state of affairs was processed to deliver the overall street lighting profile (technologies, energy and cost) of each island. Specific measures adjusted to the profile of each island were proposed based on the principle that we are aiming at energy and cost efficient systems incorporating innovation (LED technology and control systems), but also formulating the economic conditions that would allow investment under an ESCO or PPP scheme. The proposed measures were focused on the replacement of most of the existing low efficiency lighting units (luminaires and lamps), combined with the implementation of small-scale control systems taking into consideration the expected new smart grid infrastructure. The final proposals were formulated in sub-groups of interventions, starting from the measures with the shortest payback period and gradually escalating to full integrated scenarios, including all the intervention sub-groups.

The average technical economic figures can be summarized in the following tables. Actions 6 and 7 are proposed only for a selected small part of the street lighting network for demonstration. For example, dimming of the lighting (measure 6) can only apply in areas with low population density, while tele-management can significantly increase costs if applied in the whole network. The energy savings that can be achieved by the implementation of measures 6 and 7 are estimated on top of measures 1 to 5 (that is, measure 6 or measure 7 can give an additional 20 per cent of savings calculated on the energy consumption after the implementation of measures 1–5).

Energy Saving measures		Average luminous efficacy before [lm/W]	Average luminous efficacy after [lm/W]	Average energy saving
1	Replacement of high pressure mercury luminaire with adequate LED luminaire	35	105	76%
2	Replacement of high pressure sodium luminaire with adequate LED luminaire	79	95	64%
3	Replacement of metal-halide luminaire with adequate LED luminaire	52	66	75%
4	Replacement of compact fluorescent luminaire with adequate LED luminaire	59	121	28%
5	Replacement of compact fluorescent lamps with adequate LED lamp	59	84.5	48%
1-5	Combination of measures 1-5	N/A	N/A	43-68%
6	Dimming with predefined pattern in selected parts of the street lighting network (demo measure)	N/A	N/A	20%
7	Dimming through tele-management in selected parts of the street lighting network (demo measure)	N/A	N/A	20%
1-7	Combination of measures 1-7	N/A	N/A	50-72%

Lighting points concerned					
Measure no.	Lesbos	Lemnos	Santirini	Milos	Kythnos
1	4316	2313	1625	1069	18
2	3865	263	178	8	0
3	79	130	376	44	7
4	2645	2459	4903	1506	743
5	548	568	4778	1122	359
6*	291	180	3144	352	370
7	305	60	130	116	50

* The measure will be applied to lighting points not used during the low season.

Simple payback period					
Measure no.	Lesbos	Lemnos	Santirini	Milos	Kythnos
1-5	6.5	6.4	6.7	7.2	8.0
1-7	6.6	6.5	6.7	7.4	-

Having analysed the technical and economic characteristics of the proposed project a financial analysis was carried out based on the assumption that the project would be 100 per cent financed by the municipalities themselves taking advantage of loan schemes provided for public authority investments with low interest rates (3–5 per cent) and long maturity (up to 25 years). The analysis was carried out assuming the maximum payback period (25 years), interest rate fixed at 5.26 per cent and discount rate at 5 per cent. The results regarding investment cost and net present value after the payback period are presented below.

	Combination of measures 1-5		Combination of measures 1-7	
	Investment cost (€)	NPV after 25 years (€)	Investment cost (€)	NPV after 25 years (€)
Lesbos	5,174,467	2,944,454	5,534,851	2,716,070
Limnos	1,640,159	1,054,815	1,935,596	934,628
Santorini	1,374,039	1,062,726	1,964,721	679,372
Milos	721,866	361,557	919,063	227,156
Kythnos	32,993	49,002	-	-

The owners of the lighting points are the five municipalities, which are now also the promoters of the project and will be the beneficiaries of the investment due to the lower operational costs. PPC is also concerned since it owns the conventional power plants fuelled by heavy oil or diesel and is still the sole conventional electricity producer on the five islands.

DAFNI has undertaken a dialogue with the five municipalities in order to define the investment programme for each island, among the possible options that came up from the detailed analysis. In addition, DAFNI is examining the possibilities of public funding that can eventually provide low interest loans to the island municipalities for the implementation of the investment programme. The ESCO model is also currently being examined; in this case an ESCO will undertake the investment, installation, operation, monitoring and maintenance of the street lighting networks in question.

Nevertheless, the study of the above cases for the five islands has shown the big differences existing between urban areas (where the majority of applications have been located so far) and island communities with mainly rural characteristics. First of all, islands are not homogeneous and it is necessary that such territories be divided into zones with more or less the same use and even the same density. Second, the existing old infrastructure is comprises a variety of technologies and light devices. Third, the tourist islands in particular do not have the same lighting demands in every location; in some areas there is activity only for a few months. This is why the selected islands differ in terms of size, fluctuation of street light needs and annual electricity consumption. The conclusion is that no single scenario covers all the islands, and for every case a specific study is needed, followed by a cost-benefit analysis if third-party financing is the preferred method of financing/operating.

3.4 Case Study 2: LED Street Lighting and EPC in German Municipalities

LED is currently on the path towards maturity in the technology lifecycle, although LED lighting still features high upfront costs, especially compared with conventional technologies. In Germany, LED sales are growing due to numerous initiatives at the federal level. Until 2013 the National Climate Initiative provided subsidies to municipalities for switching to LED, which covered 30 per cent of the costs, on average.

The LED Lead Market Initiative, launched in 2009, brings together market players and policy decision-makers to identify barriers for the municipal diffusion of LED. These activities take place in a wider eco-design context which phases out several energy-related products, such as many conventional lighting products in 2015, because of their low efficiency. The 9.5 million public outdoor lights installed in Germany consume approximately 4 billion KWh of electricity per year, which corresponds to energy costs of about €750 million. This represents approximately one-third of municipal energy costs. The potential savings by using new energy efficient lighting systems (especially innovative LED) amount to €400 million per year, although numbers regarding refurbishments of old lighting systems are lacking. Germany's market for public street lighting is highly dispersed, consisting of more than 11,000 municipalities with individual decision-makers. An important feature of public street lighting in Germany is the prominence

of local multi-utility companies (MUCO) known as Stadtwerke, providing municipal lighting services. Although strong local embedding³ ensures near monopolies in most supply and waste streams, providing incentives for integrated solutions, this arrangement can represent a barrier to competition. The primary motivation for municipalities to engage with suppliers such as ESCOs is the promise of final energy services, such as lighting at a lower cost compared with in-house or MUCO provision. The German energy service contracting market, one of the largest, most heterogeneous and most mature in Europe with approximately 250–500 active companies, has experienced stable growth in recent years. Among the dominant companies are EUCos,⁴ MUCOs⁵ and ESCOs. EPCs are gaining acceptance among customers, although the market has reached only 10 per cent of its potential. We identified 10 companies that offer lighting services to municipalities, which include subsidiaries of EUCos or infrastructure providers. Historically, different forms of governance in the provision of lighting have emerged; 27 per cent of municipalities provide street lighting in-house, 35 per cent outsource the management to EUCos, another 10 per cent to MUCOs and 25 per cent partially outsource services, such as maintenance. A total of 3 per cent of municipalities employ an ESCO to manage their street lighting. Figure 1 presents the main actors in the process.

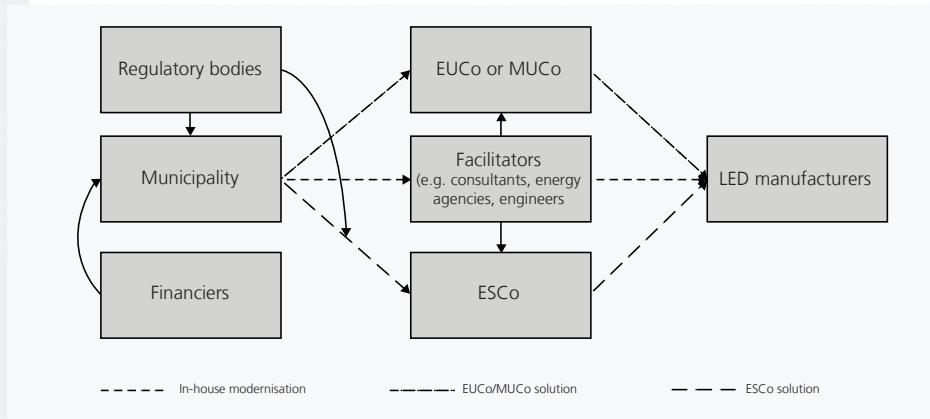


Figure 1: Overview of actors and modes of lighting governance

Source: SPRU – Science Policy Research Unit, University of Sussex

3 Regulatory bodies oversee municipal finances and partially have to approve budgets, especially when the municipality is in financial turmoil. Financiers mostly consist of (government-owned) banks.

4 EUCO stands for (national) energy utility company, which typically engage in energy generation and supply. They may also engage in distribution and transmission.

5 <http://www.eosenergystorage.com/technology-and-products/>

Generally speaking, the choice of supplier represents a choice of governance structure. In-house provision represents a hierarchical governance structure. EUCO contracts can be considered relational contracts as they focus on the terms of the relationship, while MUCO contracts fall in the same category, although their contractual relations can be more dynamic as their business model may shift towards privatization (market) or re-communalization (hierarchy) of municipal enterprises. In fact, Germany is witnessing a trend towards re-communalization, with one-third of respondents to one study indicating interest in more hierarchical approaches, specifically for energy supply. ESCO provision represents long-term contracts, the most market-based governance structure.

ESCOs may be able to provide certainty about savings in production costs for a specified quantity and quality (performance) of lighting if the replacement with LED EUEDs can be financed, operated and maintained over the duration of a contract at lower cost compared with in-house or EUCO/MUCO provision. The complexity of long-term energy service contracts compared with relational contracts or conventional in-house procurement of equipment increases the technical costs of negotiating and managing the relationship with the (energy) service provider or manufacturer (combination of human capital specificity and bounded rationality). Consequently, production costs resulting from the physical characteristics of the energy system and the technical efficiency of organizational arrangements need to be lower for this model to be economically viable.

The case of energy service contracting for public sector LED street lighting provides a good example as potential savings are high (for example, LEDs are ten times more efficient than halogen for the same light output, the capacity of municipalities to invest in these EUEDs is, as mentioned above, limited, while others streamline the outsourcing process by offering standardized contracts. Municipal benefits of abandoning the in-house approach in favour of energy service contracting may arise out of reductions in energy costs, less exposure to energy price fluctuation and the transfer of risk, allowing the municipality to focus on core activities. EPCs are only possible if the ESCO succeeds in addressing technology factors, competency and capacity factors, as well as institutional factors.

Factors affecting the diffusion of LED street lighting and EPC

Technological factors: LED lighting provides a technological advantage over conventional lighting which is a main driver for its use: higher energy efficiency.

Thus this technology exhibits a high potential for energy (and production cost) savings, which would suit an outsourcing solution. The first set of barriers to modernization comprises technological aspects such as the maturity of the products, complexity and uncertainty regarding energy savings and lifetime. LED customers such as municipalities and ESCOs in particular further are often highlighting the missing standardization and short warranties of LED due to the early stage in the innovation cycle, as well as technological path-dependency related to less innovative and less efficient lighting systems which are currently being installed. As municipal representative suggests, technical change and the lack of standardization may increase opportunism on behalf of the technology providers. These barriers translate into higher technical costs, such as the technical asset specificity of LED lighting and the task complexity of assessing technology offers up-front and M&V for potential savings.

Competency and capacity factors: A push for open-book accounting was a robust success factor in lowering technical costs. The availability of consumption figures lowers the risk of opportunism on behalf of the municipality because anticipated cost-savings are one of the main drivers for municipalities to modernize their lighting infrastructure. This lowers the human capital specificity of EPC as it reduces the ESCO's need to acquire information to perform the contract. Certainly, one of the main barriers is the municipal accounting system. Usually the overall costs for running their lighting systems are higher than what we estimate during the planning process (ESCO). The interviewees further highlighted the positive role of facilitators (for example, energy agencies) and other consultants, as well as best practice examples during the tender and implementation process as they provided the necessary lighting and planning expertise. Facilitators hold a critical position as they are able to reduce the risk of opportunism by making the task of determining cost savings less complex. These success factors lower the technical costs for both in-house modernization and ESCO solutions, as independent advice provides a more concrete overview of available options, thus reducing search costs and the human capital specificity required to search for alternative options. If, on the other hand, intermediaries and facilitators between ESCOs and municipalities suffer from a lack of lighting competence, a bias towards established technologies and a lack of understanding of the complex tendering processes, the task of determining savings may remain complex. The building and energy context require a lot of expertise. Energy consultants lack the competence for lighting functional tendering. Thus manufacturers and their tools for calculating savings dominate the market.

The low human capital specificity of facilitators increases the danger of opportunism on the part of suppliers, which increases technical costs for ESCO solutions. Cost transparency and cost management systems increase the tendency towards an EPC solution for modernization as the procuring agency can compare baseline and future scenarios. The main preconditions for effectively modernizing lighting systems are a lighting database and clear guidelines. This requires the preparation of a functional, neutral tender. The early involvement of decision-makers from local government and administration further facilitates matters. Neutral tenders ensure technology-free bidding and realization and are more likely to be an ESCO competence. Manufacturers enter into competition for collaboration with an ESCO, which results in lower prices and higher quality lighting products, which then can be implemented in ESCO projects. These factors reduce human capital specificity and task complexity as potential savings can be anticipated and adequate tenders set up, thus lowering technical costs for ESCOs as services to be provided under the contract are well defined. Competency barriers are related to the capacity of actors to overcome technological, market and institutional obstacles. Many people simply ignore the risks and undertake modernization on their own. On one hand, municipal representatives often fail to evaluate the market for LED lighting with regard to quality, energy savings and risks. Implementation of modernization is demanding. Knowledge is needed of the technical details and test examples in practice. On the other hand, municipal representatives lack the administrative competency to design tenders that appropriately reflect their quality and endurance criteria and carry out comprehensive budgeting and cost management throughout the procurement process of modern LED street lighting. Usually, municipal representatives don't even know about their own lighting costs. Data about old lighting systems in terms of energy costs, investments and so on is lacking. These competencies were not necessary in the past, as more efficient technologies evolved slowly. In the case of low human capital specificity dedicated to municipal energy management, outsourcing may be a sensible option, but the difficulty of designing tenders may provide too complex a task for a municipality to consider, translating into high technical costs and a difficult choice between realization of modernization and 18 possible outsourcing options. Our results show that responsible decision-makers tend to ignore or reject these solutions as the perceived human capital specificity is too high.

Institutional factors: From the analysis we derive institutional drivers which have a varied effect on the technical costs involved in different governance modes for modernizing municipal lighting. These include an alignment of interests between different administrative bodies that are responsible for lighting, acceptance for the new lighting technology by the local population and the procuring organization. Additionally, financial service providers act as drivers of energy efficiency projects, because they provide necessary risk and return structures. Barriers on the demand side are related to institutional problems, such as the property situation (many municipalities sold their street lighting to national EUCOs) and specific structural arrangements for the provision of public street lighting, which has historically been a task for MUCOs. Existing contracts with national EUCOs often run for a very long time and the national EUCO only complies with the legal minimum when it comes to efficiency. A switch to LEDs, which would make sense, does not happen and they use less efficient technologies. The interviewees also referred to the inadequate infrastructure for the new LED technology. Time-consuming and costly procedures to switch to another contractor translate into human capital specificity and increase technical costs for EPCs, as a favourable institutional context is needed. Experts also referred to problems on the supply side (in the ESCO market) as only a few ESCOs target the lighting market. Street lighting does not receive the attention it deserves in terms of potential cost savings and improvements in quality of light.

Manufacturers, which could also act as ESCOs, did not show a willingness to enter the service-based market segment as they perceived the margins as low and complexity as high, although they act as providers of secondary conversion equipment. Specialized ESCOs gain a competitive advantage in the field of lighting, although the low competitiveness in the ESCO market increases technical costs as it reduces the likelihood of municipalities considering outsourcing using EPCs. When, on the other hand, municipalities are willing to engage in ESCO solutions, experiences tend to be positive. The risks taken by the ESCO surpass the amount of financial savings made when modernization is undertaken in-house.

In this case the human capital specificity associated with lowering the risk of in-house EUED retrofit is too high, which reduces technical costs for long-term contracts and more market-based governance structures. Efforts required to govern the relationship are related to the task complexity and human capital specificity of negotiating and monitoring contracts. There is a complexity problem

(many contract documents are longer than 50 pages long). Regarding energy service contract design, the experts highlight transparency, comprehensibility and a distinct guarantee for energy savings as beneficial. Guidelines, transparency of the energy service contract and an ESCO that selects high quality products turned out to be successful.

Increasing know-how and enabling structures for the modernization process could significantly reduce the task complexity of outsourcing, particularly if contractual arrangements align interests by providing transparency and flexibility. Regarding the energy service contract design, municipal actors in particular also emphasized the need for flexibility (for example, to change or improve lighting systems) and a fair balance of interests during the contract as a prerequisite for EPCs. We need flexibility regarding short- medium- and long-term developments in the market. An exact definition of the baseline, however, often proves difficult. Complexity of EPC leads to high technical costs. Exact numbers are needed.

EPCs also need to be checked by the regulatory bodies when municipalities run on a very tight budget in need of consolidation. The regulating authorities need to approve the energy service contract. Financing for the duration of the contract, needs to be assured. Administrative approval represents a dedicated institutional resource for mitigation against bounded rationality on the part of the municipality. Additionally, long-term partnerships with manufacturers are often in place, which create technological and product-related lock-in effects. Manufacturers possess a lot of market power and are the winners in this market. They dictate the tenders because of the abovementioned long-lasting partnerships and thus can charge individual prices for each customer, for example ESCOs, MUCOs or EUCOs, and often supply analyses for free. Many tenders thus specify one product. Contractual barriers are also associated with lighting arrangements with national EUCOs, which prevent ESCOs from entering the public lighting market. The contracts (with national EUCOs) run for a very long time. Municipal representatives no longer have expertise.

In sum, the institutional complexity of opening up lighting provision to EPCs as well as partnerships with manufacturers, MUCOs and EUCOs tend to increase task complexity and in turn technical costs for outsourcing as they complicate the distribution of responsibilities among the actors involved.

Economic/investment factors: Economic drivers result from production cost savings, which EUCOs and MUCOs can realize by lowering the cost for energy and better procurement conditions thanks to long-lasting contracts with manufacturers. However, these companies might be subject to a conflict of interests, as they are engaged in selling electricity as opposed to providing energy efficient services. Finally, traditionally conservative attitudes towards innovative technologies may also prevent them from deploying LED. ESCOs, on the other hand, possess better procurement conditions for lighting equipment, which potentially favours an outsourcing solution. Economic barriers stem from the relatively high upfront costs of LED street lighting, particularly for municipalities as they typically run on a tight budget, in some cases tightly controlled by regulatory bodies with budgetary control powers (see Figure 2). Volatile energy prices and uncertain price developments for LED further constrain the payback of investments. These factors prevent municipalities from realizing significant production cost savings, a prerequisite for using any mode of governance for modernization. EUCOs and MUCOs, on one hand, possess knowledge about the current lighting system and experience in providing maintenance services for the municipality. Hence a EUCO/MUCO solution may have lower aggregate production costs for the provision of the energy service. ESCOs, on the other hand, often lack finance as they are not well established among financial service providers. ESCOs need to refinance themselves. However, forfeiting is not accepted by many municipalities. This leads to financial constraints on the ESCO side. Thus an ESCO solution might exhibit higher financing costs, which lowers its potential to cut production costs.

Factors affecting local authority decisions

The initial view of many local authorities is to reduce energy costs by switching off or operating street lighting for shorter periods. While this may provide short-term relief in energy costs it takes no account of the hidden costs to the community in terms of increased calls to the emergency services and the disruption of people's lifestyles, as well as a decrease in the use of public transport due to fear of walking to and from it on dark streets. The direct and indirect costs associated with switching off street lighting also need to be taken into account when making such decisions.

Today, it is possible to adapt public lighting to the needs of each user. A light management system suitable for the needs of users can also achieve the financial

savings required by public authorities. In fact, the middle ground must be a compromise between the two parties. Simply switching off existing equipment is not the solution in the long term. A global solution must be found for tomorrow's smart street lighting.

The most economic solution is not a solution that works everywhere and all the time. For example, a solution with permanent detection is not adapted in a residential street. Indeed, switching on and off public lighting as cars, pedestrians and bicycles travel might become an issue for the residents in terms of intrusive light. A global solution for public lighting cannot be improvised.

Public lighting is no longer only a light source, a reflector and a luminaire. It is a global solution that needs to be implemented: source, photometry, luminaire, installation, maintenance, management and interconnections. A broader reflection on the needs of the different parties must be initiated. The latest technological progress offers the ability, in this period of crisis, to put in place structural savings in the public lighting sector.

Maintain lighting and generate savings: an example

Since the first roads were lit, lighting and methods of lighting have evolved significantly. This is not the case for the type of sources that equip our road and highway network, which has remained unchanged over 30 years: low pressure sodium light. Admittedly, its lighting efficiency (lumen/watt) remains unmatched. But today, it is not only the efficiency of the source that needs to be considered.

In the meantime, other types of sources have evolved in various aspects: light efficiency, colour temperature, colour rendition, lifetime and finally, dimming ability versus lifetime. The widespread use of electronics in auxiliaries makes it possible to offer new features (constant lumen output, adjustable lumen output). The same equipment improves the operation of sources with better regulation of supply voltage, power factor and so on. Finally, control options (unidirectional and bidirectional) can manage not only the light flow, but also the light in its totality (running time, source mortality, failures). Recent progress has brought optimized maintenance for public lighting.

However, there is one domain where we can still improve: managing lighting levels based on needs at the time it is required.

Take, for example, a road where the public lighting needs to be replaced. The public authorities are asking for several technical solutions for the project. These solutions must satisfy several needs:

- retrofit HPS (high-pressure sodium) or LED
- estimate annual energy consumption.

In this context, we add two complementary criteria to estimate the efficiency of the luminaire or the installation:

- service level: percentage of users (vehicles, pedestrians, cyclists) who benefit from the light at night
- loss level: ratio between the accumulative time of absence of users when the light is switched on and night duration.

A traffic evolution model during the night is required to estimate service and loss levels. These values do not depend on the lighting level at the time a user is under the switched on light. In the context of this paper, we considered the entire installation and not a unique luminaire.

3.5 Q&A for Further Reading

What about light pollution?

Each of the above proposals is based on reducing the use of electrical energy by reduced operating hours, reduced lighting levels or a combination of both. As well as reducing the consumption of electrical energy these measures will also provide reductions in light pollution. The simple switching off of a street light or reduction of its light output for a defined period of time will obviously reduce the level of light pollution during that period; however, it will not reduce the level of light pollution at times of full operation. The use of modern light sources in high performance optics can show reductions in energy consumption as well as reductions in light pollution if the lighting class is carefully chosen to reflect the use and location of the road, while maintaining the amenity provided by the lighting system.

Switching off or removing street lighting?

It is simple and quick to switch off a street light by removing the main service

fuse in the cut-out at the base of the lighting column. However, care needs to be taken when doing so and consideration should be given to the damage that will occur to the electrical equipment due to non-use. Following the mass switch off of lighting equipment during the 1970s and 1980s industrial disputes many authorities reported that they had to replace ballasts, ignitors, photo cells, time switches and capacitors due to the ingress of moisture. In many instances the cost of repairs was significantly higher than the savings in energy. There is also a serious road safety issue if unlit columns are left in the highway as obstructions.

Do the light devices affect electrical safety?

Many distribution network operators (DNOs) are concerned about the safety implications and the possible risk to the security of their network caused by street lamps being switched off and left unused for long periods of time. It is understood that some may require the owners of such equipment to have the electrical service removed and made safe. The cost of this work would be rechargeable to the authority and should be taken into account when determining the cost benefits of switching off street lighting.

Are there any additional charges?

The unit cost of street lighting electrical energy is an average of the cost of the energy over the whole night and takes account of high peak costs, as well as low costs during the early hours of the morning. If the consumption of energy pattern is significantly altered – for example, by operating street lighting for only part of the night – it is possible that the energy suppliers may wish to adjust the unit cost of energy to reflect this different pattern of use. This could have implications for the level of savings that can be achieved and should be taken into account when calculating the financial benefit of switching off street lighting.

Part of the cost of electrical energy consists of charges for use of the distribution system and the transmission system and is paid to the distribution network operator and the Grid for the provision and operation of their systems. If the service cable is not disconnected and removed the energy supplier is justified in making a charge to cover these charges and to pay this to the DNO and the Grid for the provision and maintenance of their network. These charges can add up to a considerable proportion of the unit cost of energy (up to 40 per cent) and should be taken into account when calculating the financial benefit of switching off street lighting.

3.6 Recommendations

There are many ways in which the use and thus the cost of electrical energy for street/public lighting can be reduced; however, these will generally require the authority to »invest to save«. It is recognized that the cost of converting lighting to part-night lighting is less than fitting variable level (dimming) control gear; however, the benefits of lighting are lost when the lights are switched off whereas if the lighting is reduced to a lower level it will still provide illumination giving security and safety to all road users, particularly pedestrians and cyclists.

In any case, municipalities may review their previous strategies after publication of the revision of the European Standard EN13201 (December 2014) that allows adaptive lighting and the use of dimmable lighting systems, as this could totally change the landscape of electric lighting by achieving savings of up to 50 per cent.

The careful choice of lamp type and lighting class can also provide lower energy consumption, further reducing costs. When reviewing their lighting policies, authorities should take care not just to replicate or provide a lighting class to the same levels and quality as previously used classes without carefully considering all the requirements of the European Standards.

In conclusion, specific measures for islands and/or rural areas may include:

- replacement of mercury vapour luminaires by efficient ones
- replacement of old and depreciated luminaires by efficient ones
- replacement of non cut-off luminaires
- installation of dimming units in systems with conventional lamps
- use of LED luminaires with internal dimming units
- dimming of luminaires during specific time intervals.

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ABBREVIATIONS

LED	Light-Emitting Diode
ESCO	Energy services company
EPC	Energy performance contracting
PPPs	Public-private partnerships
MUCO	Multi-utility company
HPS	High-pressure sodium
TC	Technical cost
PC	Production cost
EUED	Energy demand reduction technology

4. Electric Vehicles Infrastructures

Summary

Over the past few years there have been a number of efforts to discuss many aspects of electric vehicles or plug-in electric vehicles within electrical distribution networks. While significant and valuable consideration has been given to the “end game” in terms of architecture and the control of tens of thousands of electric vehicles, there has been little discussion or direction given on the prioritization of requirements concerning the scaling of systems from the level of a limited pilot (for example, 10–30 electric vehicles) to multiple, but limited deployments of systems.

The second point is related to the chicken – egg problem: the national/local authorities could not proceed to the financing of infrastructure without a guarantee from the demand (users and car companies). On the other hand, car manufacturers and dealers, are not willing to introduce new cars in a national market without having resolved the infrastructure issue.

The discussion currently is mainly related to the rationale of implementing an electric vehicle control system, including the various fundamental requirements of such a system at the most basic level of implementation and aggregation of electric vehicles. One of the most important components of the electric-vehicle ecosystem is consumer signalling and subsequent billing of electric-vehicle energy flow. Thus important aspects of metering this energy use have to be discussed while the incorporation of the electric vehicle control system into a larger energy management system remains under discussion.

Furthermore, the storage of electric power for e-mobility solutions, the adaptation / transformation of existing charging prototypes to local conditions (especially in islands) and the manufacturing of all peripheral equipment for the integrated solutions (including communication, metering, smart grids, card payments and so on) are some potential objects of research and development, especially for countries without a national car industry (such as Greece).

A very important option is the life – cycle analysis of the electricity in use. The substitution of fossil fuel electricity and the reduction of CO₂ emissions in transports, implies the possibility to feed EVs with clean non fossil energy. For

island systems the surplus renewable energy production (now rejected) could be the most promising option. This option requires, among others, Energy Management Systems (EMS) linked to the local distribution grids.

Finally, the main challenge for islands with a big potential for RES (solar, wind, geothermal, ocean power) is to profit from the under construction smart and integrated systems allowing the intercommunication between consumers and energy providers. Furthermore, the increased penetration of renewables in the system should maximise the availability of green energy locally and to use the rejected energy from RES. In these terms, green electricity and cheap rejected energy from RES in islands could perfectly fuel the future fleet of electric vehicles. The benefits are both from the production side (clean and renewable energy) and the use as well (zero emissions).

Over the past few years there have been a number of efforts to discuss many aspects of electric vehicles or plug-in electric vehicles within electrical distribution networks. While significant and valuable consideration has been given to the »end game« in terms of architecture and the control of tens of thousands of electric vehicles, there has been little discussion or direction given on the prioritization of requirements concerning the scaling of systems from the level of a limited pilot (for example, 10–30 electric vehicles) to multiple, but limited deployments of systems.

The consideration of programme scaling concerning the use of electric vehicles within an electrical network is focused primarily on three components:

(i) Costs/benefits. Development and integration costs of stakeholder systems (operation of distributed generation, integration with renewable energy sources, distribution operations and other activities) can be quite expensive and without known benefits if characteristics of the electric vehicle system are not known beforehand.

(ii) Complexity. Architecture, as it relates to sensing, signal processing and controls, combined with communications and latencies can negatively impact overall system complexity, which drives up costs, especially in autonomous grids (for example, islands).

(iii) Consumer preferences. Electric vehicles are a consumer-owned resource and, correspondingly, direct control of electric vehicles by a third party introduces consumer preferences into the availability of the resource, unlike other distributed energy resources available to the utility. This behavioural aspect of electric vehicle operation must be incorporated early in the design and implementation process or significant consumer backlash could result.

The current discussion refers mainly to the rationale of implementing an electric vehicle control system, including the various fundamental requirements of such a system at the most basic level of implementation and aggregation of electric vehicles. One of the most important components of the electric-vehicle ecosystem is consumer signalling and subsequent billing of electric-vehicle energy flow. Thus important aspects of metering this energy use have to be discussed. Finally, incorporation of the electric vehicle control system into a larger energy management system is under discussion.

The dispatch of stored energy to the distribution grid – so-called »V2G« or Vehicle to Grid operations – is considered a technology for the future. The primary reason for not providing any detail on this capability is that it simply does not exist on a wide scale outside academic research. The major impediment to V2G operations is that they accelerate the end-of-life of installed vehicle batteries, and this negatively impacts the consumer value of their electric vehicle and jeopardizes warranties from automotive manufacturers. There are also many issues surrounding safety, customer compensation for energy provided and the impact on electricity suppliers, which need to be worked out. Until these points are addressed a widespread capability for discharging electric-vehicle batteries to the distribution grid simply will not develop.

In Greece, the main legal framework for charging-station infrastructure is provided by the Regulation on Electricity Provider Permits (Article 135 of Law 4001/2011), Ministerial Decree 71287/6443 of 31 December 2014, National Law 4070/2012 and Ministerial Decree 50 of 15 January 2015. These define the terms and conditions for the permissions needed to install charging stations in existing (conventional) fuel stations, parking areas and so on or in those under construction). It is noteworthy that the Greek Regulatory Authority for Electricity (RAE) in 2014 announced a public consultation on the regulatory and operational framework for integrating the charging infrastructure for electric

vehicles in the Greek market in order to examine and select the optimal design and implementation of the relevant project, as well as to attract investment interest <[www. http://www.rae.gr](http://www.rae.gr)>.

Furthermore, the RAE is examining (under consultation) the spatial distribution of charging stations in urban and semi-urban areas (private, public and industrial places), the role of the Hellenic Electricity Distributor Network Operator (HEDNO), which will be responsible for designing the Network of Electric Mobility (NEM) and the management of metering data, and the establishment of rules of communication between charging stations and electric vehicles.

Concerning the sale of energy, the main debate is about the model to be used for the configuration of future energy providers in the final stage (consumers). RAE is examining three scenarios:

- (i)** The existing electricity providers obtain a sales permit (Article 134, Law 4001/2011) to provide electricity to their clients through direct cooperation with infrastructure development companies (joint venture, payment with specific cards and so on).
- (ii)** The constructors/owners of charging stations obtain permission and become official electricity providers.
- (iii)** The constructors/owners of charging stations buy electricity from existing energy providers with permits and sell the electricity to their clients, the owners of electric vehicles.

Electric Vehicle Market Basics – Types of Electric Vehicle

At the time of writing (April 2014) there are three broadly accepted types of on-road electric vehicle for commuting and highway use: battery electric vehicles (BEV), plug-in hybrid electric vehicles (PHEV) and fuel cell vehicles (FCV). Plug-in electric vehicles (PEV or EV) refer collectively to PHEVs and BEVs.

- Battery EV (BEV) – incorporates on-board storage of energy to provide the necessary drive of a vehicle. These vehicles have limited range and must use charge points frequently.
- Plug-in Hybrid EV (PHEV) – incorporates a standard combustion engine and regenerative braking in combination with on-board storage of energy to

provide the necessary drive of a vehicle. These vehicles may optionally plug into an electrical supply, but can fully charge using the on-board motor. When the on-board energy storage is depleted the source of power is typically a petroleum-based fuel.

- Fuel-cell Vehicle (FCV). Fuel-cell vehicles run on hydrogen gas and do not consume power from the electric grid. They are attractive because they have no emissions, but they are also quite expensive in comparison with their PHEV and EV counterparts. They are mentioned here because they can potentially become a dispatchable energy resource (DER) and could provide energy to the distribution grid. Despite this, no further mention is necessary as their penetration is anticipated to be low for many years due to the cost of the vehicles and the cost and limited availability of charging infrastructure.

Support for the Electric Vehicle Market

The market for electric vehicles is growing due to the regulatory environment driving alternative fuel policies, technology innovation, and customer demand for electric vehicles.

The deployment of electric vehicles supports two key initiatives: energy independence and environmental health. Electric Driving means shifting the transportation industry from petroleum-based combustion fuels to domestically-generated electricity. The shift to electricity as a transportation fuel also means a decrease in vehicle emissions, both greenhouse gases and criteria pollutants. The carmakers have taken advantage of key technology innovations to mass produce new PEV models. As battery technology improves in energy density and reductions in cost, plug-in electric vehicles will become a practical solution for many drivers.

As more and more customers are exposed to electric driving and the range of models increases, customer demand will grow.

A common issue for all alternative fuels (except LPG) is the lack of infrastructure for energy supply to the customer (refuelling/recharging points). The build-up of infrastructure therefore is a necessary – though not sufficient – condition for broad market development of all alternative fuels. Moreover, even when this infrastructure exists, the relevant standards are not the same EU-wide.

At the moment we are caught in a vicious circle. Investors are not putting their money into building alternative fuel infrastructure because there are not enough vehicles and vessels to use it. These, in turn, are not being offered by manufacturers at competitive prices as there is not enough consumer demand. And consumers do not buy the vehicles because the infrastructure is not there. There is a gap between successful demonstrations and the real market, which the private sector is unable to reach at the moment.

4.1 Current Situation – Key Figures

The current and foreseeable situation of the development of alternative fuels in Europe and worldwide is as follows:

A breakdown of worldwide sales of electric vehicles (EVs) in 2011 shows that the United States (19,860) is by far the biggest market, followed by Japan (7,671) and some European countries: Germany (1,858), France (1,796), Norway (1,547) and the UK (1,170). China only sold 1,560 EVs and India 585. On the other hand, 7,500 charging points are installed in the US, 1,500 in China and 1,100 in Japan. In the EU, there are 1,937 charging points in Germany, 1,700 in the Netherlands and 1,356 in Spain (2011 data).

On the basis of national plans, it is expected that the diffusion of electric vehicles and plug-in hybrid electric vehicles (PHEVs) will be as follows: in the US 1 million vehicles by 2015 and in China 5 million vehicles and 10 million charging points by 2020. France expects to have 2 million vehicles by 2020, Germany 1 million by the same year, the UK 1.55 million and Spain 2.5 million.

The introduction of hydrogen and fuel-cell vehicles has been very limited to date; several hundred demonstration vehicles (cars, buses) and just over 200 fuelling stations are active worldwide (120 of them in the EU), with over 100 more at the planning stage. Major OEMs – including Daimler, Toyota, Honda, GM, Hyundai and Nissan – are preparing for the first product roll-out around 2014/2015, though this will only amount to several thousand vehicles in the run-up to 2017. Germany, Japan, Korea and the US are leading – with China and India now making early moves. In the EU, Scandinavia, the UK and Italy are also active.

4.2 What is the Problem?

The full-scale deployment of electric vehicles has been held back by three main barriers: the high retail cost of vehicles, a low level of consumer acceptance and the lack of infrastructure for recharging and refuelling.

The availability of recharging stations is not only a technical prerequisite for the functioning of alternative fuel vehicles, but also one of the most critical components of consumer acceptance. The importance of infrastructure for alternative fuels has been recognised by a large number of EU member states, regional and local authorities.

Policy initiatives from the EU and member states have mostly addressed the development of alternative fuels and/or alternatively fuelled vehicles and vessels, without considering the need for building up an appropriate alternative fuel distribution infrastructure. The efforts of the member states and the EU to give incentives for the development of alternative fuel infrastructure have been uncoordinated and insufficient.

4.3 What is the European Commission Proposing?

The Commission is proposing action to ensure the necessary infrastructure build-up across Europe, with common standards for interoperability.

The minimum coverage requirement of recharging/refuelling points for electricity, hydrogen, LNG for maritime waterborne and road transport and CNG shall be implemented before 31 December 2020.

The relevant technical standards for the same fuels shall be adopted and implemented before 31 December 2015. Member states shall ensure that clear and simple information on the compatibility of fuels and vehicles is available by the date the directive has to be transposed into national law.

No public spending is required for building up alternative transport fuel infrastructure if the member states use the wide range of measures available to mobilise private investment cost-efficiently.

Recharging points

The situation for electric charging points varies greatly across the EU (see Table 1). The leading countries are Germany, France, the Netherlands, Spain, Austria and the UK. Therefore, the network is focused on key cities and there is not yet a critical mass for development of the market. Germany established a target of 1 million vehicles by 2020; 4 billion euros will be devoted to promoting electric cars until 2015.

The United Kingdom established a target of 1.55 million vehicles by 2020; 300 million euro was to be devoted to promoting electric cars between 2009 and 2014. France established a target of 2 million electric vehicles by 2020. In addition to introduction schemes for consumers up to 7,000 euro, France will devote more than 450 million euro to install adequate public charging infrastructure in its 25 biggest urban areas by 2014.

Spain established a target of 250,000 BEVs and PHEVs by 2014 and 2.5 million EVs by 2020.

The proposal: A minimum number of recharging points is required for each member state. This is based on the planned number of electric vehicles; 10 per cent of these should be publicly accessible (see Table 1).

The total estimated cost of the proposed development of electric charging points in the EU will be approximately 8 billion euro.

The impact: The aim is to put in place a critical mass of electric charging points, at which it will become interesting for investors and companies to mass produce the cars at a reasonable price for a growing market and consumers have the confidence to buy the cars.

The German government wants to bring 1 million battery-powered vehicles onto the roads of Europe's largest economy by the end of the decade.

Germany plans to expand the network of charging stations for electric cars across the country to help boost lacklustre demand. The government wants to bring 1 million battery-powered vehicles onto the roads of Europe's largest economy by the end of the decade.

But high vehicle costs and drivers' concerns about infrastructure and limited battery range have held back sales in Germany to just 24,000 out of a market of about 3 million cars, according to government data. Germany currently only has about 100 quick service charging points for electric cars, allowing drivers to recharge batteries in less than an hour, and about 4,800 charging stations running on alternating current, according to the Transport Ministry.

The Transport Ministry paper said German motorway services operator Tank & Rast GmbH was due to set up quick service charging stations and parking spots at its 400 sites by 2017. The Berlin-based government will shoulder some of the costs of installing cables and related construction projects.

Source: World Bulletin/News, 28 December 2014

member state	Existing infrastructure (charging points) 2011	proposed targets of publicly accessible infrastructure by 2020	Member state plans for number of electric vehicles by 2020
Austria	489	12,000	250,000
Belgium	188	21,000	-
Bulgaria	1	7000	-
Cyprus	-	2000	-
Czech Republic	23	13,000	-
Germany	1937	150,000	1,000,000
Denmark	280	5,000	200,000
Estonia	2	1,000	-
Greece	3	13,000	-
Finland	1	7,000	-
France	1,600	97,000	2,000,000
Hungary	7	7,000	-
Ireland	640	2,000	350,000
Italy	1,350	125,000	130,000 (by 2015)
Lithuania	-	4,000	-
Luxembourg	7	1,000	40,000
Latvia	1	2,000	-
Malta	-	1,000	-
Netherlands	1,700	32,000	200,000
Poland	27	46,000	-
Portugal	1,350	12,000	200,000
Romania	1	10,000	-
Spain	1,356	82,000	2,500,000
Slovakia	3	4,000	-
Slovenia	80	3,000	14,000
Sweden	-	14,000	600,000
United Kingdom	703	122,000	1,550,000

Table 1: Minimum number of electric vehicle recharging points in each member state

Source: Clean power for transport, European Commission, 24 January 2013

Technical Specifications

The current situation: There are two main types of charging points in Europe.

This could lead to a situation in which a car that travels from France to Germany cannot be refuelled.

The proposal: Common standards for electric charging points across Europe must be designed and implemented by December 2015.

The impact: The aim is to ensure that electric cars can circulate freely across the EU.

The initial costs for alternative fuel infrastructure (electricity, for instance) are generally higher than those of petroleum-based fuels, especially due to the lack of economies of scale and the small number of circulating vehicles (»chicken and egg« problem).

In this respect, it is necessary to set up a policy framework to create the conditions for fuel suppliers and distributors to invest in this sector with confidence.

In particular, first-mover investors would be instrumental in the development of an alternative fuel infrastructure network. First-mover investors and to a lesser extent follower investors face high up-front costs and uncertain payback times for investments due to the low diffusion of alternative fuel vehicles and vessels and, as a result, the initially slack demand for these fuels.

The policy instruments that have been identified as suitable for protecting first-mover investors are: the granting of exclusivity rights, awarding concessions, direct public financial support, public guarantees, self-regulation through strategic alliances and the use of public procurement. The choice of the appropriate policy instruments should be up to each member state on a case-by-case basis.

The main question: Is public spending required for building up alternative transport fuel infrastructure in the member states, or is the wide range of measures available to mobilise private investment cost-efficiently enough?

The German Experience: e-Mobility Berlin

The project e-Mobility Berlin undertaken by RWE and Daimler is one of multiple projects within the model region Berlin/Potsdam. In a full service renting model, customers get a smart for two electric drive, together with intelligent charging management, an intelligent charging box and free »green electricity« for 18 months. Furthermore, RWE is planning to install 500 charging stations in Berlin. In Germany as a whole they have already installed 1,000 charging stations.

Within the project RWE and Daimler want to gain practical experience of e-Mobility. One result of that is a standardisation of the connection between the charging station and the electric vehicle. This standardisation allows a simple "Plug & Charge" concept and communication between the electric vehicle and the charging station over power lines. Additionally to conventional contacts, the connector has also two additional signal pins (proximity or plug present, control pilot). The "plug present" pin detects the presence of the car, the control pilot handles the communication between the car and the charging station. This system allows a quick charging with 400V up to 32A. This means a power of 22 kW in comparison with 3.7kW using a normal domestic plug. A charging time of 1 hour is therefore possible.

Once the connection between the vehicle and the charging station is established the vehicle registers itself. The charging management of the charging station detects the customer and releases the charging point. In the next step the charging of the vehicle begins and the consumption is measured. Once the charging process is finished the consumption is sent to the RWE control centre and linked to the customer's account. The customer gets a bill on a three-monthly basis.

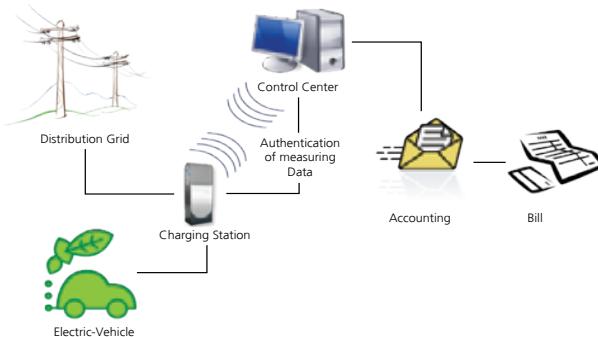


Figure 1: Charging process project »e-Mobility Berlin«

Source: Electromobility in Berlin-Brandenburg, www.emo-berlin.de

MeRegio Mobil and Modellregion Stuttgart

The project MeRegio Mobil is being implemented in a model region around the cities of Stuttgart and Karlsruhe. The aim of this project is to develop and test information and communication technology (ICT)-based e-Mobility key technologies and services. The project is based on the Minimum Emission Region (MeRegio) project, which investigates the intelligent use of energy in domestic premises. Therefore, households are provided with different forms of equipment, such as:

- Smart meters, intelligent freezers, local batteries and solar panels
- Customer display units, access to internet portal, time-of-use tariffs.

Providing some of these households with electric vehicles and charging stations, such as a wall-box in the MeRegio Mobil project is a consistent follow-up to the MeRegio project.

The consortium implementing the projects includes, among other utilities, car manufacturers, research institutes and charging station manufacturers. The leader of this consortium is Energie Baden Württemberg (EnBW).

Within the framework of the project 110 charging stations have been installed in public, semi-public and private places. These charging stations provide electricity to both 230 E-Vehicles and 500 E-Bikes. The reason for the enormous number of E-Bikes was to identify the charging and using behaviour of the clients. The customers can get access to the charging station by using an RFID-card (radio frequency identification) which opens the charging point.

Every RFID-card has a biunique number which is connected with its owner. The charging stations have a white list of RFID-card numbers which are accepted by the charging stations. By extending the white list and providing more RFID-cards the range of customers can be extended as well.

The charging stations consist, among other things, of smart meters that measure the electricity consumed and are always connected to the back-end-system of the utility. These meters are registered in the back-end systems like normal domestic meters. The metering point is linked with the energy supplier's »green-energy« tariff.

The charging process starts and finishes with the customer placing their RFID-card in front of the charging station. The charging process and therefore the electricity consumed are connected with the RFID-card number and thus with the customer. All charging processes are listed on the customer's electricity bill, which is submitted at the end of every month.

4.4 Electric Vehicle Control Systems – Fundamental Requirements

For the plug-in electric vehicles described above, the act of plugging the vehicle into the grid presents a demand to the distribution system if the vehicle state of charge (SOC) is not at 100 per cent. The range of this demand can vary and is a function of the on-board vehicle electronics, as well as the electric vehicle supply equipment or charging point (EVSE or CP). The range for electrical demand for the industry (today) is between approximately 3 KW to in excess of 50 KW, with a nominal 6–7 KW infrastructure being recommended for most residential use. The most typical use for electric-vehicle owners is to commute from work to home, plug the vehicle into their home EVSE/CP, and forget about it until the following morning. The act of plugging the vehicle into the EVSE/CP, apart from a delayed start feature, immediately initiates the charging cycle, and although a 6–7 KW charging demand could double the household demand at any given time, individual and low population use of electric vehicles has a benign impact on the distribution grid and is not a concern to the utility distribution system operator.

A major consideration with regard to the penetration of electric vehicles is the localization or concentration of EVs within the distribution grid. As penetration increases relative to the static architecture of the distribution grid, average demand on localized distribution assets increases, potentially causing hotspots that overload existing low-voltage infrastructure. The most typical observation is premature failure of low-voltage distribution transformers, and failure analysis has revealed that the devices were simply too hot and internally failed.

To counteract this situation the owner of the transformer asset has two options:

- (i)** replace the failed transformer with the next larger size, or

(ii) implement a control structure that influences the charging of electric vehicles to take advantage of lower simultaneous demand periods (off-peak). While the first option is quite viable and has advantages for the utility, the second option typically can create other value components for the utility, namely:

1. the ability to create sensing and control infrastructure which can provide a return on capital opportunities;
2. the ability to influence load behaviour to the advantage of distribution operations, for example, voltage compensation, power factor correction and removal of localized constraints; and
3. the ability to take advantage of variable prices for energy and interact with consumers, empowering consumers to make economic charging decisions.

To realize these value components, an electric vehicle control system (EVCS) must be implemented. The EVCS is the system responsible for aggregation and response of individual EVSE/CPs, as well as their connected electric vehicles. In the most basic of implementation, the EVCS should be able to notify consumers that charging at certain times could be financially beneficial, and in more advanced EVCS implementations, these actions could be performed automatically, simultaneously benefiting the utility and the electric vehicle owner. In most cases, the higher the level of automation implemented the greater the potential financial benefits for stakeholders.

Value as a function of aggregation of assets

Initially, ad hoc ownership of electric vehicles is not necessarily advantageous to the electricity supplier in terms of aggregation of EV assets. This is because the electrical and geographical penetration of electric vehicles is low and the impact on electrical demand is negligible from a concentrated electrical loading point of view. As EV penetration increases, one of the first benefits of being able to aggregate demand from electric vehicles is to be able to estimate loading levels on distribution assets. The results of these estimates then permit system planners to properly engineer in terms of time (when do we need to upgrade the distribution asset?), quantity (what is the peak capacity requirement vs nominal?), and specific assets (if transformers are upgraded, do supplying segments, feeders and other associated infrastructure need to be upgraded?).

As answers to these basic questions become discernible, budget estimates for infrastructure can be determined. As is often the case, the rate of growth of demand can often outstrip available resources to supply that demand, hence putting pressure on other systems to »smooth the load«. It is in this context that aggregation of assets can provide significant monetary value to the energy supplier or DSO.

This initial integration of EVSE/CP data to the utility, and subsequent aggregation of endpoints according to various groupings, immediately creates value for the utility in the following areas:

- Grouping by LV distribution transformer permits loading as a function of the electric vehicle charging cycle;
- Grouping by segment or feeder, which is typically upstream of the LV distribution transformer, permits classification of electric vehicle loading to be determined as a percentage of demand;
- Grouping by substation, which typically is upstream of the feeders and segments, permits classification of electric vehicle loading as a percentage of demand. Early in the rollout of these programmes the loading at the substation is often quite light and is at the threshold of measurement, so despite the low values, initial impact can be quantified.

Value to system planning functions. The aforementioned discrete groupings are useful for the system planning function within a utility, as they provide growth rates of electric vehicle penetration, which directly impacts planning activities for the 1–5 year time frame. Additionally, this »virtual metering« capability opens the door to other value streams, as AMI data can be aggregated in the same manner to provide equivalently useful data.

Value to demand response/pricing programs. As charging characteristics are established (equivalent time of day, equivalent demand levels, equivalent patterns, coincidence), demand response programs can be designed that can simultaneously benefit the utility, as well as the consumer. Charging characteristics shape the cost of energy that must be provided, and if peak shifting or peak reduction is desired, directly influence the time of day rate structure offered to electric vehicle owners and consumers.

Value to volt control systems. As electric vehicle penetration increases,

coincident demand will impact voltage levels on distribution assets. By using pricing incentives as well as autonomous control it is possible to influence charging such that voltage variations due to loading can be stabilized. The primary component of this function is to initiate charging on the remote electric vehicle, which will facilitate stabilization of voltage; when (and if) vehicles are allowed to dispatch to the grid further stabilization is possible.

Value to renewable integration systems. As electric vehicle penetration increases, the ability to use (initially) the demand from them to absorb energy from renewable systems is a key capability that needs to be developed, thus taking advantage of electric vehicles' storage capabilities and their symbiotic relationship with renewable sources. As vehicle manufacturers enable vehicle-to-grid (V2G) operations from their electric vehicles the utility will be able to take advantage of dispatch of this energy for grid-support operations.

To realize these value streams early in the EV/EVCS deployment process, the following requirements apply to the EVCS architecture:

- The EVCS must receive revenue-grade measurements from each of the EVSE/CP installed within the distribution network in a timely manner.
- The EVCS shall have an integrated capability to perform aggregation of metering points, or if not internally aggregated, shall have the capability to interface with a third-party vendor to provide this capability (aggregation = »virtual metering»).
- The EVCS shall interface with the utility's asset management system (AMS) so that electrical distribution assets (LV transformers, segments, feeders and substations) can be associated with specific EVSE/CP endpoints. These requirements should be implemented with the initial EVCS, independent of the number of EV assets connected to the distribution system, so that value can be quickly established as the system is realized. Outside an automated system, the utility should find a way to encourage notification that an electric vehicle is present on the system or will be added to the system in order to gather as much information about customer EV adoption and how it may impact the distribution assets. Although this type of arrangement would not allow monitoring and measurement, it is critical to at least be aware of the presence of electric vehicles.
- To properly capture the value of aggregated EV assets, in addition to the aforementioned requirements, the following additional requirements exist for the EVCS.

- The EVCS shall have the ability to interface with utility or third-party systems capable of providing day-ahead notification to electric vehicle owners concerning pricing and optimum times to charge their vehicles. This notification shall minimally be text/SMS and email notification to the asset owner.
- The EVCS shall process »opt-out« notifications received from the consumer for pending events and shall not interact in any capacity with the consumer for those events.
- The EVCS shall have the ability to interface directly with the EVSE/CP or with a third-party aggregator who provides transparent control functionality for EVSE/CP charging.
- The EVCS shall integrate with utility operations such that information concerning renewable generation levels are available to the EVCS for scheduling of the charging of electric vehicles.

Energy management system / Electric vehicle control system

A number of solutions exist that permit simultaneous charging of different vehicles from the same electric vehicle service equipment (EVSE). Reserved for commercial and industrial settings due to the power requirements (sizing of conductors from the electricity mains), these EVSE are to be considered multiple EVSE under a common enclosure. Because of this, there is an economy of scale that results compared with separate systems because common items such as connection points, communication interfaces and so on result in a lower cost of goods during manufacturing and shipping. For public charging infrastructure there could be a measurable procurement saving if this configuration is used.

As electric vehicle penetration increases, the charging (and potentially discharging) of electric vehicles can be used for stabilization of grid voltage, as it applies to volt compensation or optimization programmes. Another obvious use case is the potential to use electric vehicles to smooth the intermittency due to renewable energy sources (RES), such as solar or wind. The concept is simple – charge the electric vehicle from the RES and discharge it when the RES goes away.

Unfortunately, as of 2014, there was limited availability to discharge energy from electric vehicles back to the grid (outside academic research) due to vehicle manufacturers and their concerns surrounding the warranty of their EV battery systems. Vehicle manufacturers warrant their electric vehicles to the minimum

extent possible, and as available today, the warranties only cover the well-understood and quantified behaviour of charging the vehicle, as well as driving x miles per day. Any further decrease in battery lifetime and available energy outside of normal driving operations is not yet available from any manufacturer. Having said that, there are architectural configurations that can be implemented early and they will not be a stranded investment. Specifically, nodal aggregation/disaggregation capabilities will permit multiple levels of measurement, control and stabilization to occur as EV resources and RES are presented in the distribution system. By correlating electric vehicles and RES to common subnodes, load profiles can be stabilized (for example, ramp charging upward as solar or wind increases bus voltage). If (or when) EV energy dispatch is permitted, it may be possible to obtain steady-state load values at various nodal locations in the network.

4.5 Infrastructure for Greek Islands

At the time of writing there is limited vehicle adoption and charging infrastructure support in Greece and adjacent countries. These two items are often seen as a cyclical problem: customers do not purchase electric vehicles because there is no infrastructure to charge them and there is resistance to deploying charging infrastructure because there are no vehicles to use it.

To be discussed in later sections are the characteristics and benefits of various pilot deployment configurations of chargers so that lessons can be learned on use, impacts to the grid and customer adoption.

The non-interconnected islands (NII) are to be interfaced with an energy management system (EMS), which is referred to as the EMS-NII. This EMS is centralized in design: information for the generation and load assets of each island, is to be relayed to the EMS-NII system for coordination, processing and possible remote control.

The primary function of an EV control system is to influence the charging and discharging behaviour of the connected electric vehicle. As energy supplies become constrained, the proposed method of controlling the electric vehicle is to shift its charging to the period when energy supplies are not constrained. For the initial implementation of EV charging systems two things are particularly

desirable, assuming that one primary goal of the pilot is to measure the maximum impact that the deployment of 13 chargers can have on distribution infrastructure: a) Concentration of EV charging in terms of electrical interconnection, and b) Similarity of use case.

For the DoE, we want to be able to determine a set of scaling rules for follow-on implementation. Unfortunately, individually-isolated assets of small magnitude cannot be aggregated artificially with the same benefit/outcome as locally concentrating assets and measuring their impact on the surrounding distribution network. Hence, we need to aggregate the initial 13 vehicles of Lesbos as electrically close as possible.

Aggregation, in isolation without consideration of use case, would produce less than optimum results. Here, »use case« refers to the intended use/function of the interconnected assets. In this case, it is strongly desirable to have as many of the electric vehicles exhibiting the same use – all are fully-charged at some point in the day, and all are returned with some state of discharge at another coincident point in the day. Structuring the DoE this way ensures that it is possible to quantify the maximum impact of demand.

Implementation of the option with public access and concentrated deployment of the EV charging stations offers the best architecture to achieve a centralized and natural aggregation of assets due to the expected high benefits, low complexity and low potential impact to customer. Candidates for such implementation are: a) A fleet parking area, such as at a local utility, public works or other commercial entity with internally-owned electric vehicles; b) A car rental parking area; c) A municipal parking area.

In the first two cases it is presumed that vehicles are fully charged in the morning and return at the end of the day in some state of discharge. It is under these conditions that load-shifting can be accomplished and that the impact on distribution assets can be quantified. This permits the development of scaling rules as more electric vehicles are deployed in the island environment.

Figure 2 shows the relative time of day and demand curves for Lesbos. All are bi-modal in nature, with summer (red) exhibiting the greatest demand due to a higher population, as well as air conditioning. As can be seen, summer peaking

occurs at about 13.00h and then again at 21.00h. It is strongly desirable that any controllable loads – »elastic loads« – be shifted such that they do not contribute to the demand peaks. Indeed, a gradual ramp-in and ramp-out of elastic loads is desirable so that the 13.00/21.00 summer peaks can be reduced and/or flattened.

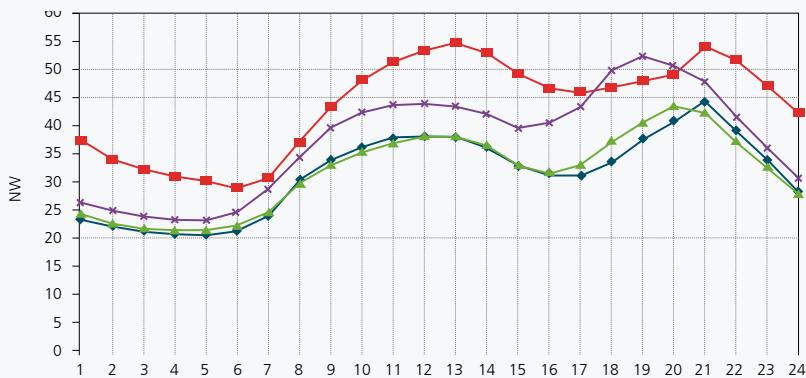


Figure 2: Typical daily curves for working days for the island of Lesbos (blue: spring; red: summer; green: autumn; violet: winter).

Source: ECCO International, Inc., 2014

Photovoltaic (PV) capacity on Lesbos is approximately 7.77 MW; another 2.8 MW is presently under construction. PV production typically begins at sunrise, peaks between 13.00-15.00h daily and it drops off to zero, near sunset. The impact of the additional solar on Figure 8-5 will be a continued (minor) reduction of the 13.00h peak but virtually no impact of demand on the 21.00h peak. Of course there is a seasonality impact too, with winter months resulting in less PV output than summer months. Of particular importance is the magnitude of the 21.00h summer peak – it is nearly of the same average value as the 13.00h summer peak. Note that the winter (violet) second daily peak occurs at about 19.00h and is considerably larger than the winter mid-day peak. This second peak is important in an EV charging context – if the electric vehicle is connected to the grid without any advanced control it is highly probable that its charging will contribute additional demand that coincides with the system peak. For a large-scale implementation on a normal working day (daylight hours) this is the exact use case that needs to be mitigated.

Based upon the foregoing, the following recommendations are proposed for islands like Lesbos:

- The preliminary charging stations should be centrally located to one customer in either a private or a mixed access situation, depending on identified goals and priorities. Coincidence is presumed to be high in this scenario and this is the only chance to determine scaling rules for the impact of EV demand on distribution assets on Lesbos.
- The charging stations should (ideally) all be utilized using the same use case in order to maximize impacts on the system. Coincidence is presumed to be high in this scenario, and this is the only chance to determine scaling rules for the impact of EV demand on distribution assets on Lesbos.
- The EMS and EV control system should have real-time metering information. In this case »real time« is a reading from the endpoint at least once every five minutes or faster.
- The number of EV charging systems should be increased as soon as finances allow leverage of the existing infrastructure and further establish scaling rules.

On smaller islands with a small number of charging stations at the beginning (1–4 charging stations per island) the impact of EV energy management will be largely undetectable except at the low-voltage transformer which serves the EV charging point. While this impact is of interest, monitoring and transmission of these data will require an infrastructure that serves only one endpoint. Consequently, costs will be quite high, as will technology risk/risk of technology obsolescence, while tangible, quantifiable value will be low. Based on this, we make the following recommendation concerning integration of the EMS-NII and EV control system in the remaining islands:

Due to cost constraints, it is highly recommended that there be NO EMS-NII / EV control system integration for small islands until the number of endpoints is increased.

While an integrated system may not make sense on the islands aside from Lesbos, it will still be valuable to monitor power quality, charger usage and driver experience. Once the number of end points increases, the roll-out of integration of the EMS-NII system and island EVCS can occur, which will be based largely upon the lessons learned in the Lesbos deployment.

Standards involving connection of electric vehicles to a micro-grid

The standard MV and LV distribution grids are considered fairly stable in terms of frequency, voltage variations and overall reliability. This is termed »stiffness«, and a frequent comment is that in a standard electrical distribution network a given node (generally an interconnection between the source and load) is to be considered "stiff". This characteristic allows loads to be connected / disconnected in an ad hoc manner with no significant regard to distribution operations.

On the other hand, micro-grid operation generally is not considered a stiff network. The introduction of renewable energy sources (RES), often comprising wind, solar or other energy storage systems (for example, pumped hydro) can introduce significant variability into the local grid due to large variations in the availability of supply. Consequently, the incremental addition of a new source of energy, or a new load of any substantial size, can have an impact on supplied voltage and frequencies. This has significant implications for interconnected EV subsystems.

Paraphrasing a previous statement, it will be many years before electric vehicles are permitted to dispatch their energy to a local grid (V2G), primarily due to the challenges associated with warranties on the vehicle battery systems. Hence, from the perspective of the micro-grid, the vehicle, at least for the foreseeable future, will appear as a large load that will be transient in both time and location within the electrical network.

Having said that, there is a number of considerations to be addressed, in case of electric vehicles operated in islands (or isolated) electrical network. These are:

1. Concentration: The greater the number of electric vehicles at the transformer, feeder or substation level, the greater the potential impact on electrical performance of those assets.

2. Coincidence: Even if the concentration is high at a given level of aggregation/asset, dissimilar charging use cases could stabilize or make negligible the impact of electric vehicles on the local grid.

3. Mode: As proposed, electric vehicles will only be available in the near-term as a load asset, meaning that their stored energy is not available for dispatch purposes. This will significantly limit the impact of the EV systems as a higher concentration with large coincidence will be required in order to measurably quantify the benefits of these systems.

Cost of EV charging systems

A number of considerations apply to the cost of the EV charging system. Primary cost drivers are associated with the internal power electronics, specifically the amount of energy that can be delivered to the electric vehicle. Overall costs vary as a function of capabilities of the EV charging system, namely, level of metering and communications capabilities, in addition to being a function of rebate and other vehicle manufacturing programme incentives.

Representative costs for chargers range from around €700 to €4,000, and between €7,000 and €30,000 for more advanced and high-power DC chargers. Advanced features, such as magnetic card readers, RFID and enhanced back-office interfaces can drive costs upward. User interfaces, such as in-situ displays, can add several hundreds euro to the cost of a charging point/EVSE. Here, the use case for implementation is important – if it is about part of a fleet, then enhanced capabilities are not needed. If a stand-alone unit for public charging, then user interfaces are required, as are methods of charging/billing. Presently, as the number of EV charging systems increase, the acquisition costs of the systems will continue to decrease. Pricing information is not readily available as it depends on the overall size and scope of the project. If it is critical to have a better understanding of pricing in order to design the initial pilot, it is recommended that a Request for Information (RFI) be made. The RFI can also be used to determine which products could be available for Greece.

4.6 Challenges for R&D

In recent years there has been intense interest in the development of charging stations with direct current (DC), which allow the direct electricity infusion from an external set of batteries charged in an alternative way (for example, using photovoltaics). This method has the following advantage: there is no need for heavy infrastructure for transforming the alternating current (AC), especially in high power demand situations.

Furthermore, the storage of electric power for e-mobility solutions, the adaptation/transformation of existing charging prototypes to local conditions (especially in islands) and the manufacturing of all peripheral equipment for the integrated solutions (including communication, metering, smart grids, card

payments and so on) are some potential objects of research and development, especially for countries without a national car industry (such as Greece).

Finally, the main challenge for islands with a big potential for RES (solar, wind, geothermal, ocean power) is to design integrated systems allowing maximisation of the penetration of renewables in the system in order to maximise the availability of green energy locally and to use the rejected energy from RES (due to the limited grid capacity) and the excess of the potential RES capacity (energy cannot be consumed locally).

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ABBREVIATIONS

AC	alternating current
BEV	battery electric vehicles
CNG	compressed natural gas
CP	charging point
DC	direct current
DER	distributed energy resource
DSO	distribution system operator
EMS	energy management system
EMS-NII	energy management system for non-interconnected islands
EV	electric vehicle
EVCS	electric vehicle control system
EVSE	electric vehicle service equipment
EVSE	electric vehicle supply equipment
FCV	fuel cell vehicles
HEDNO	Hellenic Electricity Distribution Network Operator
LNG	liquid natural gas
LV	low voltage
NEM	network of electric mobility
OEM	original equipment manufacturer
PHEV	plug-in hybrid electric vehicles
RAE	Regulatory Authority for Electricity
RES	renewable energy sources
RFI	request for information
RFID	radio frequency identification
SOC	state of charge
V2G	vehicle to the grid

The Aegean Energy Agency (AEA) is a non-profit organization established in 2008. AEA is the supporting organization of DAFNI network, an association of 33 island local authorities and 2 regional authorities from the Aegean Sea. The primary goal of AEA is to catalyze cooperation between island authorities and investors in order to mature and implement bankable projects on Greek islands in the fields of renewable energy, energy efficiency, sustainable transport and mobility. Further, AEA encourages the participation of local authorities and citizens in energy investments through new investment schemes and/or cooperatives, raises awareness on the need for citizens to adopt responsible energy behaviour and establishes strategic partnerships to promote sustainable solutions for insular regions at European and international levels.

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The Friedrich-Ebert-Stiftung (FES) is a non-profit German political foundation, with representation across the globe, committed to the advancement of public policy issues in the spirit of the basic values of social democracy through education, research and international cooperation. In May 2012 the foundation reopened its representation in Athens in order to promote the dialogue between progressive forces in Greece and Germany in the light of the current economic crisis, thus contributing to a better understanding between the two countries. Together with its partners, i.e. political parties, trade unions, NGOs, think tanks, universities, and state institutions the Athens bureau deals with a large number of political, social and economic issues, focused on reduction of youth unemployment, promotion of renewable energies, reform of the public sector, fight against right-wing extremism and much more.

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