

2009 Technology Map of the European Strategic Energy Technology Plan (SET-Plan)

Part – I: Technology Descriptions

JRC-SETIS Work Group



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European Commission
Joint Research Centre

Contact information

Address: P.O. Box 2, 1755 ZG Petten, the Netherlands

E-mail: evangelos.tzimas@ec.europa.eu

Tel.: +31-224-565149

Fax: +31-224-565616

<http://setis.ec.europa.eu>

<http://www.jrc.ec.europa.eu/>

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2009 TECHNOLOGY MAP

of the European Strategic Energy Technology Plan (SET-Plan)

Part I: Technology Descriptions

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PREAMBLE

In 2007, the SET-Plan Technology Map was published by the JRC to underpin the Communication from the Commission that established the European Strategic Energy Technology Plan (SET-Plan). The Technology Map contributed to the identification of the SET-Plan technology priorities, i.e. the technologies with the greatest potential to contribute to the transition to a low carbon economy. The 2009 update of the Technology Map, prepared by the SET-Plan Information System (SETIS), responds to the need for updated information on low carbon technologies, which is essential for the implementation of the SET-Plan. It comprises two parts: Part I, which is the work at hand, describes energy technologies and Part II analyses the impact of deployment of the SET-Plan technology priorities. The *Technology Descriptions* of the Technology Map contribute to the further definition of the first European Industrial Initiatives in 2010 and, most importantly, to the setting of a technology description (cost & performance) baseline for monitoring technological progress.

The *Technology Descriptions* of the 2009 Technology Map assess the technological state of the art and anticipated developments of 17 energy technologies, the status of the corresponding industries and their potential, the barriers to large scale deployment, the needs of the industrial sector to realise the technology goals and the synergies with other sectors. The technologies addressed are: wind power, solar photovoltaics, concentrated solar power, hydropower, geothermal energy, ocean energy, cogeneration of heat and power, carbon capture and storage, advanced fossil fuel power generation, nuclear fission, nuclear fusion, electricity grids, bioenergy for power generation, biofuels for transport applications, fuel cell and hydrogen technologies, electricity storage and energy efficiency in transport.

This work was prepared by scientific experts of the European Commission, led by the JRC, in consultation with experts from the Member States and Industrial stakeholders. Finally, the contents of this document have been validated by independent experts in the frame of dedicated technical workshops.

The 2009 Technology Map is the SET-Plan reference on the state of knowledge for low carbon technology in Europe, presenting a snapshot of the energy technology market situation for 2008-2009. However, the information in this work should be seen in the context of the dynamics of the energy technology market. As such, SETIS is continuously tracking and monitoring the global development and progress of energy technologies and makes this information available “on-line” in the SETIS website: <http://setis.ec.europa.eu>.

1 WIND POWER GENERATION

1.1 Technological state of the art and anticipated developments

The kinetic energy of the wind is transformed into mechanical energy by the rotors of wind turbines (WT), and then into electricity that is injected into the grid. Wind turbines are normally grouped in wind farms in order to obtain economies of scale. Wind speed is the most important factor affecting WT performance and a site's wind speed is measured through wind resource assessment, prior to a wind system's construction. Wind speed varies depending on the year, the time of the year, location, orography and other obstacles and it generally increases with height creating the wind shear profile. Surface obstacles, such as forests and buildings, decrease the wind speed, which accelerates on the windward side of hills and slows down in valleys. For a given site, annual variations in electricity production of around 20 % are normal.

Generally, utility-scale wind power plants require minimum average wind speeds of 6 m/s. The power which can be extracted from the wind is proportional to the cube of the wind speed. When the long-term mean wind speed increases from, for example, 6 to 10 m/s, i.e. about 67 %, the energy production increases by 134 % [1]. A small difference in wind speed causes a large difference in available energy and in electricity produced, and eventually in the cost of the electricity generated.

WT start to capture energy at cut-in speeds of around 3 m/s (11 km/h) and the energy extracted increases roughly proportionately to reach the turbine rated power at around 12 m/s (43 km/h), remaining constant until strong winds put at risk its mechanical stability and the turbine is forced to stop at cut-out speeds of around 25 m/s (90 km/h).

There are two main market sectors: onshore wind, which includes both inland and shoreline installations, and offshore wind away from the coast. The differences are remarkable, due to the different working environment (saline and tougher in the sea) and facility of access for installation and maintenance. In addition, as the wind is stronger and more stable at sea, wind turbine electricity production is higher offshore. Current onshore wind energy certainly has room for further technology improvement, e.g. for locating in forests, for facing extreme weather conditions, etc., yet it is a mature technology. However, offshore wind still faces many challenges.

There is a market for small turbines (up to 10 kW) for niche applications such as isolated dwellings, but this sector is unlikely to provide a significant share of the European electricity supply.

Throughout the 20th century WT design (the three-bladed, horizontal-axis rotor) arose as the most cost-effective and efficient. The main technology variations of this design are:

- Upwind rotor, actively yawed, to preserve alignment with the wind direction. Rotor efficiency, acoustic noise, tip speed, costs and visual impact are important design factors.
- High-wind-speed regulation: the initially more popular stall regulation (a passive control through a specific blade design) is giving yield, especially for the larger WT, to pitch regulation (an active control turns blades along their axis to regulate the power extracted).
- Rotor speed can be fixed or variable. The former is linked to stall regulation and it is the most proven and oldest technological coupling, the grid (through the generator) is what keeps the speed constant. Variable speed was introduced to allow the rotor and wind speed to be matched more efficiently and to be connected to the grid at lower wind speeds, but it has a higher cost and certain reliability issues.

- Towers: concrete, steel or a mix of both.

The main WT technology driving goals are to minimise capital costs and to maximise reliability, which translate into: design for low and high wind sites; grid compatibility; acoustic performance; aerodynamic performance; visual impact; and offshore specifics. Technical considerations that cover several of these goals include low-mass nacelle arrangements; large rotor technology and advanced composite engineering; and design for offshore foundations, erection and maintenance.

With respect to quality of supply imposed by recent grid codes, WT are evolving from conventional variable-speed drive (class I) through to the doubly-fed induction generator (DFIG), class II turbines, currently the most popular, into the permanent magnet generator (PMG) with full (power) converter (FC) (class III), being the state-of-the-art of today [1]. PMG-FC allows grid “fault ride-through”, as required by recent grid codes. This transition is accelerating as power electronics become increasingly more affordable.

Current support structure options for offshore WT include the more popular monopile and the lesser gravity-based foundations, available for shallow-to-medium water depths. Much less common and, in fact, nearly experimental, are floating jacket and tripod foundations. Floating foundations are being explored in order to capture the very large resource available in deep-water areas.

The trend towards ever larger wind turbines (20 kW in the 1980s to a maximum of 6 MW today) has stabilised during the last years. Currently land-based turbines (98 % of all installed capacity) are mostly rated either at the 750 – 850 kW, the 1.5 – 2 MW or the 3 MW range. Economies of scale in turbine components are behind this trend, as is better land utilisation and reduced O&M costs [1]. Both industry and academia see larger turbines (10 – 20 MW) as the future offshore machines.

Rotor diameters have stabilised since 2004 at around 100 m up to a maximum of 126 m. Tip speed is limited by acoustic noise, turbines might be requested to operate at reduced speed in noise-sensitive areas, but is increasing for offshore machines to above 80 m/s. Pitch control is becoming the technology of choice (4 out of every 5 of the larger WT are already pitch-controlled), coupled mostly with variable-speed regulation. Drive trains tend to reduce their weight and offshore WT tend to stabilise hub heights at 80 - 100 m. This is because offshore wind shear is lower and there is a trade-off between higher hub heights yielding slightly higher generation and increased foundation loads involving higher tower costs [1]. Offshore foundations for deeper water are expected to diversify away from monopile steel into multi-member (jackets, tripods) in a few years and even concrete-based structures are under consideration [2].

Today’s challenges include the provision of a better service to the grid in terms of support and quality of the signal, new support structure designs in waters with depths above 30 metres [3]; price reduction and improved efficiency of power electronics for PMG-FC, reducing the weight (and cost) of drive trains and thus the nacelle mass. The specific concerns for offshore wind farms include the minimisation of maintenance requirements and facilitating feasible access.

The main lines of research include: larger turbines, drive-train innovations and offshore installation - related issues. Blades are tending towards larger designs focusing on joined blades (Enercon, Gamesa), improved load and fatigue testing (LM Glasfiber), winglets to reduce tip losses, blade load measurements through optical fibre strain gauges, manufacturing speed-up and use of hybrid composites.

Drive research includes: large single slew-ring-type bearings (Vestas V90), 2- and 3-point bearing systems, toothed belts for pitch systems; direct drive, leading to simpler nacelle systems, increased reliability, increased efficiency and absence of gearbox issues; hybrid drive trains generally leading to

very compact drive trains (Clipper, WinWind) and lighter systems (Prokon Nord Energiesysteme M5000, 310 t). Wind turbine controllers that can realise additional functions (individual blade pitch, generator torque, etc.), thus reducing the mechanical loads on the turbine [1].

New system concepts include experimental technologies, such as floating turbines (the already installed HyWind by StatoilHydro/Siemens and in the future SWAY/AREVA-Multibrid) to explore deep waters, and less-developed concepts, such as airborne turbines (kite, balloon or auto gyros concepts including Magenn and MAGLEV) or the electrostatic generator (TU Delft) with few mechanical parts.

Research on wind conditions includes: resource, design conditions and short-term forecasting; a focus on complex terrain, understanding wakes; offshore meteorology; and extreme wind speeds. Research on wind energy integration includes: wind power plants that operate, as far as possible, as conventional power plants; grid planning and operation, wholesale market and balancing operations; variability and forecast errors; and high-wind penetration levels.

Examples of some interesting ongoing innovations include: transport and installation, either mounting blades in parts (Enercon) or using a crane in situ to lift the whole hub plus blades (Nordex' 550 t crawler transported in 36 truckloads and assembled on site); large simple front bearings (V90 3 MW); very compact and lightweight nacelle system and separation of the functions of rotor support and torque transmission (Ecotècnia), etc.

The wind market is affected by the supply/demand imbalance and the increase of raw material and component prices over recent years, exactly as seen in other manufacturing sectors. WT prices, which were expected to continue the downward trend fostered by technological innovation, detached from that trend in 2004 to increase by up to 40 % in two years (US, Canada [4]), markets that along with China, presented the most significant market demand since 2005.

Investment costs for onshore projects showed a reduction to 1 020 €/kW in 2004 and then climbed to reach 1 410 €/kW in 2008 for 2009 deliveries. However, lower WT demand was the basis of an 18 % price reduction at the beginning of 2009 to 1 150 €/kW (2009 currency) [5, 6, 7]. Offshore investment costs have been even more affected by supply-chain limitations and thus less subject to price reductions. They climbed from 2 200 €/kW in 2007 to 2 490 €/kW in 2008 and even higher to a maximum of 3 560 €/kW in 2009 [2, 5].

Onshore operation and maintenance (O&M) costs are around 12 – 17 €/MWh and, over a 20-year operation period, constitute 30 – 40 % of total costs. They have presented a declining trend from the 35 €/MWh of the old 55 kW WT [1, 8]. Offshore O&M costs at 15 – 33 €/MWh with an average of 20 €/MWh in UK farms [9], are higher mainly due to the high cost of getting access to the turbines, even when the higher production partly compensates for the difference.

The technology progress ratio (PR) of wind turbines of 90% [10] was reflected in their real price (in EUR) up to 2003 [11], but then was overcome by market factors. A different picture is shown in the offshore sector which experienced a period of fierce competition (2000 - 2004) reflected in neutral PR and, since 2005, a negative PR inducing a doubling of capital costs up to 2009 (in GBP, 2009 real prices, [2]).

The expected capital investment trend is for onshore capital costs to reduce further and then to stabilise, due to support from the demand created mostly by the American Stabilisation funds. Thereafter, in 2 – 3 years time, costs could re-take the technology progress ratio to 90 – 92 %. Offshore wind is expected to maintain high costs for one or two years, before improved supply-chain and competition could lead to a reduction of 15 - 20 % by 2015 [2, 6, 12].

The integration of wind energy in the electricity grid can occasionally involve other costs including the reinforcement of grids, the need for additional balancing power and ancillary services. The former two items have been evaluated in Denmark, per MWh of wind electricity, at 0.1 – 5 € (for 30% wind share) and 1 – 4 € (20 % wind share), respectively [4]. These costs can be reduced through creating larger balancing areas, reducing the wholesale market gate-closure times to 4 - 6 hours, more frequent intraday markets and better forecast systems. There is also room for low-cost improvement by optimising the grid operational procedures [7].

The discussion on costs of generating wind energy often overlooks the fact that this energy is sold in wholesale markets, where all electricity negotiated, perceives the price conceded to the marginal supplier, i.e. the most expensive supplier accepted to generate. In this context, zero-fuel-cost technologies such as wind displace fuel-dependent, expensive technologies and therefore reduce the marginal price eventually paid for by all electricity traded in the corresponding period (and not just for wind power). In periods of high fossil fuel prices, the resulting multiplying effect overcompensates for any subsidy that wind might receive. Calculations in Denmark have quantified this impact, over the period 2004 - 2007, at an average of 3.3 €/MWh of traded electricity. This figure, due to a 20 % wind share, is equivalent to a saving of 16.5 € per MWh for (only) wind-generated electricity [4]. These benefits do not take into account security of supply, reduction in price volatility and the oil-GDP effect nor the cost of purchasing carbon under the European Trading Scheme.

The system availability of European wind turbines is above 97 %, among the best of the electricity generation technologies [1]. The typical capacity factors are 1 800 – 2 100 full-load hours equivalent (in which a wind turbine produces at full capacity) onshore and 3 200 – 4 000 offshore, for a European global average of 1 900. Technology progress tends to increase these figures but best sites onshore tend to have already been taken and new wind farms enjoy lower wind speeds.

1.2 Industry status and potential

The global installed wind capacity has grown this decade at a 27 % annual average, and added 27 GW in 2008 to total 121 GW (+28.7 %). Since 2004, the offshore market has contributed no more than 1.5 % of global installed capacity [2]. In the EU27, these figures were 8.5 GW to reach 65 GW (+15 %) [13]. With annual increases of 47 and 54 % respectively in 2008, the US and China installed slightly more absolute wind power than the EU27. The status of the EU as the major market is thus quickly deteriorating. During 2004, 70 % of newly installed capacity took place in the EU but this figure was reduced to 31 % after only 4 years [13, 14].

Consequently, top European WT manufacturers suffered a reduction of their global market share from 67 % [1] in 2007 to 58 % in 2008 [12], a trend that will continue this year as Chinese and US manufacturers continue to take advantage of their stronger markets. Top-10 manufacturers include Vestas and Siemens (DK), Gamesa and Acciona (ES), Enercon (DE), Sinovel, Dongfang and Goldwind (all Chinese), GE Wind (US) and Suzlon (IN).

During 2008, more wind power plants, than any other electricity generation technology, were installed in the EU (36 % of total installed capacity) and the US (45 % of total) [7, 14].

In 2008, an energy generation of 120 TWh was 3.6 % of EU electricity demand [15], whereas worldwide, wind supplied 220 TWh [13, 16]. Countries with high wind share of the electricity mix included Denmark (21 %), Spain (13 %), Portugal (12 %), Ireland (9 %) and Germany (8 %) [7]. The integration of 50 % wind power into an electricity system is seen as technically possible [17].

The European Commission's target of 40 GW by 2010 was achieved by 2005, whereas the wind industry target of 80 GW is within reach and would produce 153 TWh [15]. The 2020 industry target

of 230 GW, of which 40 GW would be offshore, is consistent with these past experiences and should therefore be considered a realistic potential. Electricity production would be 500 TWh, between 12 and 15 % of EU electricity demand [14, 15]. By 2030, the potential production is 350 GW, of which 150 offshore, and producing 935 TWh, between 21 and 28 % of EU demand [18]. The economically competitive potential of 12 200 TWh by 2020 and 30 400 TWh by 2030 [3] is beyond reach.

Globally, onshore cumulative capacity should reach 650 GW by 2020, with China and the US feasibly reaching 200 GW by 2025 [19]. By 2030, installed capacity could reach 1 080 GW and offshore wind should reach 250 GW globally by 2035 – 2040. In the EU, in the long run, offshore wind should reach 50 % of installed capacity.

The overall volume of the Chinese "new energy" stimulus fund is likely to send shock-waves through the wind industry, with strong signs that this market, along with the US, will dominate growth in both project deployment and supply chain development for the foreseeable future. Note that China's wind installations benefit from the CDM mechanism in the Kyoto agreement.

Measures announced by the US government are expected to give the strongest signal to the renewable energy industry, along with China, in the crescendo of national responses to the financial and economic crisis. In all the stimulus funds, the US has promised USD 32.8 billion (32 800 million) for renewables, compared to USD 3.5 billion by the EU and USD 1.8 billion by South Korea [2]. However, these measures, if successful and, in general, along with any improvement in the economic situation, are likely to benefit the less-risky onshore market and discourage manufacturers from developing turbines for the riskier offshore market.

The expected rise of fossil fuel prices, as the crisis continues, and the release of supply-chain problems will make average wind electricity competitive with fossil-fuel generation possibly by 2020 [2, 19].

1.3 Barriers

The main barrier to the deployment of wind energy is a high levelised energy price caused mainly by high capital costs and making wind electricity non-competitive with conventional sources. Other barriers preventing energy uptake are technological, of a local administrative nature [13], social acceptance (often after individual visual perceptions mixed up with the NIMBY syndrome) or the lack of trained, experienced staff, in particular for the expected offshore development by 2020.

The group of economic barriers include: higher raw material prices (steel, concrete, copper); low competition among second- and third-tier suppliers (drive shaft, brakes, drive-train bearings, etc.); higher turbine prices; high grid-connection costs; limited grid transmission capability that is reinforced only slowly; scarcer sites with good-resources and lately, lack of financing due to the financial crisis. Higher wind penetration is also prevented by lack of adequate interconnections, including international links, which are necessary also for the easing of balancing requirements that would be the result of a larger balancing area [1].

The economic viability of offshore wind suffers from: its inherent high risk, for example, WT manufacturers prefer to focus on the less-risky onshore market; expensive grid connections; higher entry barriers; lack of competition among offshore turbines with only two consolidated suppliers, i.e. Vestas and Siemens and very complex permit procedures [2]. The lack of dedicated offshore turbine designs of appropriate size is another important barrier.

Some technological barriers that prevent the scaling-up of turbines (in particular, offshore) include: high nacelle mass; high mechanical loads; and the transport of larger components and large-enough cranes. Specifically for offshore, more efficient vessels for installation and maintenance are needed, as

well as new support structure designs for waters with depths over 30 m [3]. In addition, technological barriers prevent new entrants to the very tight supply chain for HVAC/HVDC subsea cables, where there are only 3 European manufacturers. More research is necessary and existing EU research facilities are limited.

Grid operation should be fair and more flexible in all Member States (MS) [13]. However, new grid code demands, such as the ability to stay connected and perhaps also contribute to system stability during disturbances on the electricity system (including ‘fault ride-through’), constitute barriers only in that compliance comes at a cost [1]. The badly needed grid extension has its own barriers that should be tackled and which are different from those of wind deployment [20]. Finally, some MS still have slow, cumbersome and expensive permit procedures.

1.4 Needs

In the delicate balance among market-driven rising capital costs and technology-driven cost reductions, the sector needs more investment in RD&D, innovation and deployment. Funds should focus on large turbines, materials reduction, improved offshore installation vessels, and other technological barriers as identified above. In other sectors, such as power electronics, investing in RD&D can eventually yield significant cost reductions to the wind sector. Also, improved adaptation of power electronics to the marine environment is needed for offshore wind.

Wind energy depends on other sectors, including: the electricity grid which is a fundamental enabler for higher wind penetration and is currently underdeveloped in particular regarding international interconnections; electricity storage (pumped hydro, compressed air, etc.); and manufacture of subsea HVAC/HVDC cables. The European installed capacity of hydro-pumping storage, currently at 38 GW, should be increased in order to allow for more system flexibility. More reservoir hydro-capacity should be designed to contribute to grid support and this would enable more wind and other non-firm renewables into the system.

The EU should create the appropriate framework for the development and integration of the electricity grid to support renewable energy penetration. The reinforcement of grid interconnections and of legal/institutional measures for market integration is consistent with the general EU energy policy and a key support for, as it supports the internal market. The EU should review how connection decisions are taken by distribution and transmission system operators and take steps to increase their transparency and competitiveness. Identifying grid bottlenecks and promptly defining and applying operational measures would alleviate the problems and defer the need for grid investment.

The financial situation is likely to need support during 2009 and possibly 2010. After that period, the US and other stimulus packages will have created a completely different picture. A part of the European society is still not aware of the full extent of the climate change problem, and of the impact of wind energy to alleviate this problem. There is a need for the EU and individual MS to raise awareness that reduce the “not in my back yard” syndrome toward wind farms and their required grid connections. Last but not least, there is a need for better cooperation among the European wind industry, academia and R&D institutions in research, education and training.

1.5 Synergies with other sectors

Synergies exist between the offshore sector and the oil and gas (O&G) industry in areas such as the manufacture of installation vessels. This sector can bring in experience and know-how to the offshore wind sector, in particular on substructure installations and on operation and maintenance issues. However, some analysts suggest that this is a double-edged sword in that there is competition between

both industries for these vessels and, in the context of higher oil prices, which are expected to follow the economic recovery, the O&G industry has substantially more purchasing power.

Some ocean energy projects share grid-related issues with offshore wind and even with onshore at a lower level. Exchange of technological know-how with the aeronautics industry might result from the entry of EADS in the wind sector. Other sectors that have possible synergies with wind are the grid components, in particular for offshore installations, and electricity storage sectors. The latter, along with the auto industry for electric cars, and with the support of smart grids/metering, would create a demand-management scenario able to adapt and assimilate surplus wind electricity.

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2003-2008 into 2009/2010 gives 78 GW. For generation: similar projection of Eurostat data 2004-2007 and estimated 2008 into 2009/2010 gives 153 GW.

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2 SOLAR PHOTOVOLTAIC ELECTRICITY GENERATION

2.1 Technological state of the art and anticipated developments

In 2008, 85% of photovoltaic (PV) systems were based on crystalline silicon technology that is already highly mature for a wide range of applications. In 2008, the average turn-key price of a residential (3 to 20 kW_p) PV system in Europe was € 4.3/W_p. In 2009, the price has dropped considerably, with prices in Germany, for example, in the range € 2.8/W_p to € 3.5/W_p. Large systems, in the multi MW_p range, have a different price structure and include a higher fraction of projecting and administration cost, as well as costs to connect the systems to the grid. The price range of such systems was between 2.5 to 4 €/W_p. It has to be stressed, that the current market prices are strongly influenced by the different national support schemes and only partially reflect the true costs of the systems.

Efficiency of typical commercial flat-plate modules and of typical commercial concentrator modules is up to 15% and 25%, respectively. The typical system energy pay-back time depends on the location of the installation. In southern Europe, this is approximately 1 to 2 years and increases at higher latitudes [1]. The performance of photovoltaic modules is already guaranteed by the manufacturers for up to 25 years, but the actual lifetime of the modules is well above 30 years [2]. Finally, the average generation cost of electricity based on the actual investment costs in 2008 is about 30€/kWh, ranging between 20 and 45 €/kWh depending on the location of the system.

Crystalline silicon-based systems are expected to remain the dominant PV technology in the short term, but thin films are continuously increasing their market share. In the medium term, photovoltaic systems will be introduced as integral parts of new and retrofitted buildings. Eventually, in the long term, new and emerging technologies will come to the market, such as high concentration devices that are better suited for large grid-connected multi-MW systems, and compact concentrating PV systems for integration in buildings. It is expected that crystalline silicon, thin films and other technologies will have equal shares in the installed PV capacity in 2030. The cost of a typical turn-key system is expected to decrease from € 3.0 – 4.0 in 2009 to € 2.5/W_p in 2015, and reach € 1/W_p in 2030 and € 0.5/W_p in the longer term. Simultaneously, module efficiencies will also increase. Flat-panel module efficiencies will reach 20% in 2015 and up to 40% in the long term, while concentrator module efficiencies will reach 30% and 60% in 2015 and in the long term respectively. It is expected that if these technology developments are realised, the cost of electricity from PV systems will be comparable to the retail price of electricity in 2015 and of the wholesale price of electricity in 2030.

Both crystalline Si solar cells and the “traditional” thin-film technologies (a-Si:H and its variations based on protocrystalline or microcrystalline Si, as well as polycrystalline compound semiconductors) have developed their roadmaps aiming at further cost reductions. These roadmaps are based on growing industrial experience within these domains, providing a solid data base for quantification of the potential cost reductions. The Strategic Research Agenda (SRA) of the European Photovoltaic Platform is one example which describes in detail, the research needed for this set of PV-technologies. It also points out the opportunities related to beyond-evolutionary technology developments [3]. These technologies can either be based on low-cost approaches related to extremely low (expensive) material consumption or approaches which allow solar cell devices to exhibit efficiencies above their traditional limits. In fact, the goal to develop crystalline Si and thin-film solar cell technologies with a cost < 0.5 €/W_p, heavily relies on disruptive breakthroughs in the field of Novel Technologies. Research in photovoltaics should therefore be sufficiently open towards developments, presently taking place in material and device science (nanomaterials, self-assembly, nanotechnology, plastic electronics) to detect these opportunities in an early stage.

The Strategic Research Agenda has deliberately chosen the terms “Emerging Technologies” and “Novel Technologies” to discriminate between the relative maturity of the different approaches. The

category “Emerging” was used for those technologies which have passed the “proof-of-concept” phase or can be considered as longer term options for the two established solar cell technologies, i.e. crystalline Si and thin-film solar cells. The term “Novel” was used for developments and ideas which can lead to potentially disruptive technologies, but where there is not yet clarity on the practically achievable, conversion efficiencies or cost structure.

Within the Emerging PV-technologies, a distinction was made between three sub-categories: a) advanced inorganic thin-film technologies, b) organic solar cells and c) thermo-photovoltaic (TPV) cells and systems.

Most of the novel approaches can be categorized as high-efficiency approaches. One can make an essential distinction between approaches which are modifying and tailoring the properties of the active layer to match it better to the solar spectrum versus approaches which modify the incoming solar spectrum and are applied at the periphery of the active device (without fundamentally modifying the active layer properties).

In both cases, nanotechnology and nanomaterials are expected to provide the necessary toolbox to bring about these effects. Nanotechnology allows the introduction of features with reduced dimensionality (quantum wells – quantum wires – quantum dots) in the active layer. One can distinguish 3 basic ideas behind the use of structures with reduced dimensionality within the active layer of a photovoltaic device. The first approach aims at decoupling the basic relation between output current and output voltage of the device. By introducing quantum wells or quantum dots consisting of a low-bandgap semiconductor within a host semiconductor with wider bandgap, the current will be increased in principal while retaining (part of) the higher output voltage of the host semiconductor. A second approach aims at using the quantum confinement effect to obtain a material with a higher bandgap. The third approach aims at the collection of excited carriers before they thermalise to the bottom of the concerned energy band. The reduced dimensionality of the QD-material tends to reduce the allowable phonon modes by which the thermalisation process takes place and increases the probability of harvesting the full energy of the excited carrier. Several groups in Europe have built up a strong position in the growth, characterisation and application of these nanostructures in various structures (III-V, Si, Ge) and also on the conceptual level of ground-breaking R&D being performed, e.g. the metallic intermediate band solar cell.

Tailoring the incoming solar spectrum to the active semiconductor layer relies on up- and down-conversion layers and plasmonic effects. Again nanotechnology might play an important role in the achievement of the required spectral modification. Surface plasmons have been proposed as a means to increase the photoconversion efficiency in solar cells by shifting the energy in the incoming spectrum towards the wavelength region where the collection efficiency is maximal or by increasing the absorbance by enhancing the local field intensity. The application of such effects in photovoltaics is definitely still in a very early stage, but the fact that these effects can be tailored to shift the limits of existing solar cell technologies by merely introducing modifications outside the active layer, represents an appreciable asset of these approaches which would reduce their time-to-market considerably.

It is evident that both modifications to the active layer and application of the peripheral structures could be combined eventually to obtain the highest beneficial effects.

Research in photovoltaic devices over recent years has seen major advances in efficiency, reliability and reproducibility, but it is clear that there is the potential for further progress, both in terms of existing device structures and in relation to new device topologies. Key to these advances is an understanding of material properties and fabrication processes. Research is required for specific aspects of device design and fabrication, together with consideration of the new production equipment necessary to transfer these results to the fabrication process. In parallel, advances in the system

architecture and operation will allow the increases in cell efficiency to be reflected in the energy output of the system. Details of the needed research actions are described in the Implementation Plan for the Strategic Research Agenda of the European Photovoltaic Technology Platform [4].

2.2 Market and industry status and potential

The total installed capacity of PV systems in the EU in 2008 was 9.5 GW_p, representing approximately 1.3% of the total EU electrical capacity [5]. The electricity generated by PV systems that year was approximately 8 TWh. The annual installations of PV systems in 2008 in the EU reached 4 700 MW_p, the third largest amount of newly-built electricity generation capacity after wind and gas-fired power stations. This was due to an exceptional high installation rate in Spain with about 2.6 GW and in Germany with approximately 1.5 GW_p. Both countries have a stable, long term financial support in the form of feed-in tariffs. For 2009, the situation has changed drastically, when Spain revised its PV legislation in 2008 with a new Royal Decree 1758/2008. The new decree sets considerably lower feed-in tariffs for new systems and limits the annual market to 500 MW with the provision that two thirds are rooftop mounted and no longer free field systems. Europe currently is the largest market for photovoltaic systems, installing about 80% of world wide production and the second largest producer of PV systems, capturing about 27% of the world market as well as the world leader in PV technology development.

Based on information provided by industry, Greenpeace and EPIA have assumed in their study "Solar Generation V – 2008" that 10 jobs are created per MW during production and about 33 jobs per MW during the process of installation [6]. Wholesaling of the systems and indirect supply, for example in the production process, each creates 3-4 jobs per MW. Research adds another 1-2 jobs per MW. Based on this data, the employment figures in photovoltaics for the EU was estimated to be about 100 000 jobs in 2008 [5, 7]. However, it has to be noted that the change of legislation in Spain decreased the employment in Spain from 42 800 jobs in 2008 to less than 15 000 jobs in 2009. The affected jobs are mainly in the project realisation and module installation.

The PV sector expands annually in Europe with high growth rates, of the order of 40% on average since 2000. In 2009, the European Photovoltaic Industry Association has published its Vision for 2020 to reach up to 12% of all European electricity production [8]. However, to realise this vision and reach an installed PV system capacity of up to 390 GW_p, the industry has not only to continue to grow with the same pace for another ten years but a paradigm shift and major regulatory changes and upgrades of the existing electricity grid infrastructure are necessary.

Scenarios for the worldwide deployment of photovoltaic technology vary significantly between the 2008 IEA Energy Technology Perspective scenario and the Greenpeace/European Renewable Energy Council Scenarios [9, 10]. The IEA scenarios range between 10 GW (14 TWh) by 2010, 30 GW (42 TWh) by 2020 and less than 60 GW (120 TWh) by 2030 for the baseline scenario; 22 GW (31 TWh) by 2010, 80 GW (110 TWh) by 2020 and 130 GW (250 TWh) by 2030 for the ACT scenario; and 27 GW (38 TWh) by 2010, 130 GW (180 TWh) by 2020 and 230 GW (440 TWh) by 2030 for the Blue scenario. The European share would be about 25%. Currently, a new Photovoltaic Roadmap is under development by the IEA which revises the figures upwards. On the other hand, the Greenpeace scenarios vary between 10 GW (13 TWh) by 2010, 50 GW (68 TWh) by 2020 and 86 GW (120 TWh) by 2030 for the reference scenario; 21 GW (26 TWh) by 2010, 270 GW (386 TWh) by 2020 and 920 GW (1,350 TWh) by 2030 for the [r]evolution scenario; and 21 GW (26 TWh) by 2010, 290 GW (406 TWh) by 2020 and 1,500 GW (2,100 TWh) by 2030 for the advanced scenario.

2.3 Barriers

The main barriers to large-scale deployment of PV systems are of an administrative and regulatory nature and are mainly connected with the access to the grid. In addition, the fact that initial investment costs are still higher than in other electricity generation technologies, leads to a still higher cost of electricity from PV systems. On the other hand, however, there are no uncertain and volatile fuel cost prices with the corresponding price risks, associated to electricity generation from PV systems and the investment costs are continuously decreasing. Techno-economic barriers to the expansion of the sector include the development of advanced manufacturing systems, further optimisation along the different production value chains, and building integration of thin films. Other barriers include the lack of skilled professionals, the usage of precious raw materials e.g. silver, the need to develop methods for recycling, the introduction of new materials, regulatory and administrative barriers, such as access to grid and long waiting times for connection, and finally, lack of public awareness including construction experts.

It is noted that the issue of silicon availability has been resolved as new production units are currently under construction. The shortage of silicon in the past has been a consequence of the lack of development of new silicon purification facilities, as well as due to high rates of market growth

2.4 Needs

Research is vital for increasing the performance of PV systems and accelerating the development of the technology. Furthermore, the development of a healthy and growing market is essential for the development of PV technologies, as this will stimulate competition within the industry, which in turn will trigger further innovation. Research push tools need however to be combined with market pull mechanisms for the expansion of production capacity and the consequent development of economies of scale will lead to cost reductions. To this end, the maintenance of feed-in tariffs with built in reduction mechanisms reflecting the technology progress and market growth, is crucial for the sector for the next decade. Only a reliable framework condition, providing a stable investment environment, will allow the industry to grow and unlock the potential of this technology. Furthermore, a framework that will allow the European PV industry to compete with the rapidly increasing manufacturing capacity in Asia, will help the expansion of the sector, which will benefit further the deployment of PV systems in Europe.

2.5 Synergies with other sectors

The PV industry is not in competition with other RES-based electricity generation industries. The ultimate goal of the community that supports PV systems is to make the technology competitive with all sources of electricity in the short term and then allow all technologies to compete for their fair share in electricity generation. Moreover, the PV sector has the same concerns about electricity generation and transmission as other RES-electricity technologies, such as access to grid, financial support and approval procedures. Further synergies should be pursued with the building and construction sector for raising awareness and facilitating the integration of photovoltaic systems in new and retrofitted buildings. Shared technology developments could be envisaged with the solar heating and cooling, and the concentrated solar power sectors, with regards to materials and energy storage devices. Last but not least, it should be mentioned that research efforts in material science, nanotechnology and organic/inorganic chemistry are needed to prepare for future concepts and system solutions in order to avoid bottlenecks in the future.

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3 CONCENTRATED SOLAR POWER GENERATION

3.1 Technological state of the art and anticipated developments

Concentrated solar thermal power technology (CSP) produces electricity by concentrating the sun to heat a liquid, solid or gas that is then used in a downstream process for electricity generation. A CSP plant consists, schematically, of a solar concentrator system made of a receiver and collector to produce heat and a power block (in most cases a Rankine cycle). The majority of the world's electricity today – whether generated by coal, gas, nuclear, oil or biomass – comes from the creation of a hot fluid. CSP simply provides an alternative heat source. One of the appealing elements of this technology is that it builds on much of the current know-how on power generation in the world today. In addition, there is further potential to improve as improvements are made in solar concentrator technology, but also, as advances continue to be made in steam and gas turbine cycles.

Between 1985 and 1991, 354 MW of solar trough technology was deployed in southern California. These plants are still in commercial operation today and have demonstrated the potential for long-term viability of CSP.

For large-scale CSP plants, the most common form of concentration is by reflection, in contrast to refraction with lenses. Concentration is either to a line (linear focus) as in trough or linear Fresnel systems or to a point (point focus) as in central receiver or dish systems. The major features of each type of CSP system are described below.

Trough concentrators: Long rows of parabolic reflectors concentrate the sun by 70 to 100 times onto a heat-collection element (HCE) placed along the reflector's focal line. The sun is tracked around one axis, typically oriented north-south. The HCE consists of an inner steel pipe, coated with a solar-selective surface and an outer glass tube, with vacuum in between. A heat-transfer fluid – in general oil – is circulated through the steel pipe and heated to around 390°C. The hot fluid from numerous rows of troughs is passed through a heat exchanger to generate steam for a conventional steam turbine generator. Land requirements are of the order of 5 acres per megawatt electricity.

Alternative heat-transfer fluids, such as steam and molten salt, are being studied to enable higher temperatures and overall efficiencies. The use of molten salt, in both the solar field and thermal energy storage system, eliminates the need for the expensive heat exchangers. It also allows the solar field to be operated at higher temperatures than current heat transfer fluids allow. This combination can lead to a substantial reduction in the cost of the thermal energy storage (TES) system. However, molten salts freeze at relatively high temperatures 120 to 220°C and this means that special care must be taken to ensure that the salt does not freeze in the solar field piping during the night.

Linear Fresnel reflectors: The attraction of linear Fresnel reflectors is that installed costs, on a m² basis, can be lower than troughs, and the receiver is fixed. However, the annual optical performance is lower than for a trough reflector.

Central receivers (Solar towers): The thermodynamic cycles used for electricity generation are more efficient at higher temperatures. Point-focus collectors, such as central receivers, are able to generate much higher temperatures than troughs and linear Fresnel reflectors. This technology uses an array of mirrors (heliostats), with each mirror tracking the sun and reflecting the light onto a fixed receiver on top of a tower, where temperatures of more than 1 000 °C can be reached. Central receivers can generate temperatures similar to advanced steam turbines and can be used to power gas turbine (Brayton) cycles. Trough concentrators and solar towers also require relatively flat land, i.e. less than 1% slope for one solar field is desirable.

Dish systems: The dish is an ideal optical reflector and therefore suitable for applications requiring high temperatures. Dish reflectors are paraboloid-shaped and concentrate the sun onto a receiver mounted at the focal point, with the receiver moving with the dish. Dishes have been used to power Stirling engines at 900°C, as well as generate steam. Operational experience with dish/Stirling engine systems exist and commercial roll-out is planned. Up to now, the capacity of each Stirling engine is of the order of 10 to 15 kW_e. The largest solar dishes have a 400 m² aperture and are used in research facilities. The Australian National University is presently building a solar dish with a 485 m² aperture.

Thermal storage: An important attribute of CSP is the ability to integrate thermal storage. To date, this has been primarily for operational purposes, providing 30 minutes to 1 hour of full-load storage. This eases the impact of thermal transients, such as clouds on the plant, and of electrical transients to the grid. Plants are now being designed for 6 to 7.5 hours of full-load storage, which is enough to allow operation well into the evening when peak demand can occur and tariffs are high.

In thermal storage, the heat from the solar field is stored prior to reaching the turbine. Storage media include molten salt (presently comprising separate hot and cold tanks), steam accumulators (for short-term storage only), solid ceramic particles and high-temperature concrete. The heat can then be drawn from the storage to generate steam for a turbine as and when needed.

Availability of water is an issue which has to be addressed for CSP development, as the parabolic trough systems and central tower systems require cooling water. Wet cooling requires about 2.8 m³/MWh, which is comparable to other thermal power stations [1]. Air cooling and wet/dry hybrid cooling systems offer highly viable alternatives to wet cooling and can eliminate up to 90% of the water usage [2]. The penalty in electricity costs for steam generating CSP plants range between 2 and 10% depending on the actual geographical location, electricity pricing and effective water costs. The loss of a steam plant with state-of-the-art dry cooled condenser can be as high as 25% on very hot summer days in the US Southwest. The penalty for linear Fresnel designs has not yet been analyzed, but it is expected to be somewhat higher than for troughs because of the lower operating temperature. On the other hand, power towers should have a lower cost penalty because of their higher operating temperature.

3.2 Market and industry status and potential

Between 1985 and 1991, the Solar Energy Generating Systems (SEGS), I through IX (parabolic trough) with a total capacity of 354 MW¹, were built in the Mohave Desert, USA. After more than 15 years, the first new major capacities of Concentrated Solar Thermal Electricity Plants came online with Nevada One (64 MW, USA) and the PS 10 plant (11 MW, Spain) in the first half of 2007.

Today CSP technologies are in the stage of a first commercial deployment for power production in Europe. Due to past developments in the USA (~350 MW in operation since 1980), the most mature large scale technology is the parabolic trough/ heat transfer medium system. Central receiving systems (solar tower) are the second main family of CSP technology. Parabolic Dish engines or turbines, e.g. using a Stirling or a small gas turbine, are modular systems of relatively small size and are primarily designed for decentralised power supply. The lifetime of CSP technologies is about 20 to 30 years [1]. The solar-only capacity factor without thermal storage of a CSP plant is about 1 800 to 3 000 hours per year. The level of dispatching from CSP technologies can be augmented with thermal storage or with hybridised or combined cycle schemes with natural gas. With storage, yearly operation could theoretically be increased to 8 760 hours, but this is not economically sensible. Systems with thermal storage generally achieve capacity factors between 4 000 to 5 200 hours [1]. An experimental facility with 17 MW capacity and molten salt storage which should allow almost 6 500 operation hours per

¹ The capacity figures given are MW_e (electric) not MW_{th} (thermal)

year is currently being built by Gemasolar in Spain [3]. Several Integrated Solar Combined Cycle projects using solar and natural gas are under development, for instance, in Algeria, Egypt, India, Italy and Morocco [4].

An 11 MW saturated steam central receiver project (PS 10) is operating since March 2007 in Andalusia. This system includes 1 hour of water/steam buffer storage. A somewhat larger tower plant, PS 20 with 20 MW followed in 2009. In 2008, Andasol 1 (with 7.5 hours of storage) and the Ibersol Puertollano plant with 50 MW, each started their operational test phase and became fully operational in 2009. Andasol 2 with another 50 MW started its test operation mid-2009.

In the USA, more than 4 500 MW of CSP are currently under power purchase agreement contracts. The different contracts specify when the projects have to start delivering electricity between 2010 and 2014 [5, 6]. In Spain, CSP projects with about 1 800 MW already have provisional registration and, in addition, projects with more than 10 GW, have filed grid access applications. Plants with around 1 400 MW are currently under construction and should become operational by 2012 [7]. More than 50 projects are currently in the planning phase, mainly in Spain, North Africa and the USA [4].

Capital investment for solar-only reference systems of 50 MW_e without storage are currently in the order of 4 800 €/kW_e, varying from 2 100 to 6 000 €/kW_e. With storage, prices can go up significantly. Depending on the Direct Normal Irradiance (DNI), the cost of electricity production for parabolic trough systems is currently of the order of 18 – 20 c€/kWh (for Southern Europe, the DNI is 2000 kWh/m²/a) [8]. For DNI in the range of 2 300 or 2 700, as encountered in the Sahara region or in the USA, the current cost could be decreased by 20 to 30%. For a given DNI, cost reductions of the order of 25 to 35% for parabolic trough plants is achievable due to technological innovations and process scaling up to 200 MW_e [1].

The economical potential of CSP electricity in Europe (EU-27) is estimated to be around 1 500 TWh/year, mainly in Mediterranean countries (DNI > 2000 kWh/m²/year) [9]. Based on today's technology, the installed capacities forecasted in the EU-27, under the European Solar Industry Initiative are 830 MW by 2010, 30 GW by 2020 and 60 GW by 2030 [10]. This represents respectively up to 2030, 0.08%, 2.4% and 4.3% of projected EU gross electricity consumption. These penetration targets do not account for imports of CSP electricity. Regarding the DESERTEC scenario, which assumes that a grid infrastructure will be built within the Northern African countries, CSP electricity imports of 60 TWh in 2020 and 230 TWh in 2030 could be realised [11]. The penetration of CSP electricity for 2030 under these scenarios would be 10% of the EU gross electricity consumption.

Scenarios for the worldwide deployment of CSP technology vary significantly between the 2008 IEA Energy Technology Perspective scenario and the Greenpeace/European Renewable Energy Council Scenarios [12, 13]. The IEA scenarios range between less than 10 GW installed capacity or less than 15 TWh (Baseline) to 250 GW (ACT and Blue Scenarios) or 625 TWh (ACT) and 810 TWh (Blue) in 2030. The European share would be about 15%. No figures for 2010 and 2020 are given. On the other hand, the Greenpeace scenarios vary between 2 GW (5 TWh) by 2010, 8 GW (26 TWh) by 2020 and 12 GW (54 TWh) by 2030 for the reference scenario; 5 GW (9 TWh) by 2010, 83 GW (267 TWh) by 2020 and 199 GW (1,172 TWh) by 2030 for the [r]evolution scenario; and 5 GW (9 TWh) by 2010, 100 GW (320 TWh) by 2020 and 315 GW (1,860 TWh) by 2030 for the advanced scenario.

The European industry has currently a market leadership in CSP technologies worldwide. At this stage of development, there is a supply chain industry already able to offer turn-key equipments for power plants in the range of 10 to 50 MW. However, an industrial ramp-up in all aspects (engineering, procurement and construction, components, manufacturing, maintenance) will be necessary to go from current market shares to significant ones.

3.3 Barriers

The cost-competitiveness of CSP plants is a key barrier. There is a strong need for developing long term policy frameworks to foster and secure CSP technology developments and investments worldwide. On the technology front, component improvements and scaling-up of first generation technologies are necessary for cost reduction. The demonstration of new technologies at system level and on a relevant scale is also crucial for CSP cost-competitiveness in the long term. However, these R&D and innovation activities are not covered by industrial and private funds. As a result, there is a current shortage of equity capacity. This situation is also relevant for today's technology. The necessary work on critical elements for first generation technologies, such as adjustment of steam turbine to CSP specification, is not performed today. Reaching a critical mass among players is an essential ingredient. Nevertheless, a re-structuring of the CSP industry, as well as an expertise broadening, is on-going but it is still in its infancy. Finally, the development of specific enabling technologies, for example, grid infrastructure for importing CSP energy from neighbouring countries, is an important focus for the sector developments.

3.4 Needs

The implementation of long term frameworks with support schemes is critical to accelerate the deployment of CSP technologies. Extending the Spanish model to other EU MS in the sun-belt and fostering its promotion worldwide is important to build a global market. Joint developments with North Africa would allow the EU to benefit from higher solar resource levels. It is important to open the European market for the import of solar electricity from North Africa. A critical element of this action is the establishment of a pan-Mediterranean grid infrastructure. On the technology front, increased R&D efforts and strategic alignment of national and EU programmes are necessary to realise all the potential embedded in technology innovation. Demonstrating next generation CSP technologies is critical to address medium to long term competitiveness, but also to attract investors. Due to the private financing dilemma, innovative funding schemes will have to be developed.

3.5 Synergies with other sectors

Hydrogen production is a potential industrial field for synergies with CSP technologies. Although these concepts are at an R&D phase, current developments on the heliostat or other heat transfer components will certainly benefit this field. In the short term, shared developments can be envisaged with concentrated photovoltaics, as their concentrators respond to the same kind of usage. Other areas of developments besides electricity production are district cooling and water desalination.

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4 HYDROPOWER GENERATION

4.1 Technological state of the art and anticipated developments

Hydropower electricity is the product of transforming the potential energy stored in water in an elevated reservoir into the kinetic energy of the running water, then mechanical energy in a rotating turbine, and finally electrical energy in an alternator or generator. Hydropower is a mature renewable power generation technology that offers two very desirable characteristics in today's electricity systems: built-in storage that increases the system's flexibility and fast response time to meet rapid or unexpected fluctuations in supply or demand. Hydropower amounted to 65 % of the electricity generated from renewable energy sources in Europe in 2007 or 9 % of the total electricity production in the EU-27 [1].

A distinction between two hydropower sectors is generally accepted: small hydropower (SHP) when the plant capacity is below 10 MW or large hydropower above that figure [2]. Some authors and associations consider a further split into medium, mini-, micro- and pico-hydropower. Large hydropower is a well-established generation technology in Europe. More than 50 % of favourable sites have already been exploited across the EU-27, mainly due to the structure of the land and to environmental issues. It is unlikely that Europe could see much more expansion. Nevertheless, this market is still industrially active. Three main drivers are pushing developments in this field: worldwide erection of new large hydropower plants, with a huge market potential in India and China; the rehabilitation and refurbishment of existing hydropower facilities; and the need for the storage capability that would allow the electricity system to accommodate additional renewable power from wind and other variable sources. The refurbishment market segment is of interest for Europe with, overall, an ageing hydropower park, but also to ensure that no energy capacity losses are incurred with the implementation of higher environmental standards. Average efficiency improvements that can be expected from upgrading operations are of the order of 5 %. A renewed and growing interest for pumped storage schemes has been accounted for in the last years in Europe. These systems have cycle efficiencies steadily increasing over the decade to reach an average of 75 % in 2007 [1]. A state-of-the-art plant can reach 85 %.

Hydropower technical and economic performance is very dependent on the site specifications and utility operating strategies. Average load factors of large-scale hydropower plants range from 2 200 to 6 200 full-load hours per year in Europe, with an average at about 3 500 h. In 2008, capital investment costs for building large hydropower facilities (> 250 MW) were of the order of 1 000 to 3 600 €/kW [2]. Capital cost for hydro-pumped storage is of the same order of magnitude.

The SHP sector is differentiated between reservoir-based and run-of-river schemes. Whereas the former have a similar dam-based structure to large plants and therefore similar ways of operation and load factors, the latter operates on a continuous mode and contributes to base-load electricity.

For both small and large hydropower plants, capital investment costs are project-specific. In 2008, average capital costs for small hydropower plants (SHP, < 10 MW) were of the order of 2 000 to 7 000 €/kW [2]. Of particular interest are very-low-head hydro-turbines (head < 5 m), a promising distributed generation technology that can be implemented, for instance, in currently, untapped water resources, e.g., waterways. Their European potential is about 1 to 1.5 GW. These systems are now in the demonstration stage and their typical power rating is of the order of a few hundreds of kW to 1 MW.

An additional important driver for the development of the whole sector in Europe is the multipurpose concept. Hydropower can be implemented in combination with other activities, such as flood regulations and wetland management, with no additional water resources and environmental impacts.

It is noted that climate change can have an important influence on water resources regionally, with negative impacts foreseen mostly for southern European countries. Hydropower can itself have environmental and social impacts when new reservoirs require the displacement of populations (as in China, where 20 million people have been displaced since 1949 [3]), affect water availability downstream and flood valuable ecosystems. Dams can block river flows thus preventing silt from reaching the downstream basin. By modifying the hydrological regime of a river, dams can alter local climatic conditions and disrupt ecosystems, and habitat fragmentation is caused by large reservoirs [4]. In addition, there are reports of hydropower schemes emitting methane from decaying organic material, although it is rare and can be avoided by proper reservoir design [5].

R&D efforts address the integration of large-scale hydropower with other renewable energies, the development of hybrid systems, for example with wind, and the development of innovative technologies that minimise environmental impacts. R&D in the small-hydro sector focuses at improving fish-friendliness and the low-head equipment designs. Different materials are being investigated, including: steel alloys that are more resistant to turbine cavitations; and fibreglass, special plastics and aluminium to replace steel in some applications. Efforts are also being addressed to improve control systems and power electronics and to optimise generation as part of integrated water-management systems. For both sectors, research includes the reduction of O&M costs through maintenance-free and remote-operation technologies. One further priority is the development of cheaper technologies for small-capacity and low-head applications, to enable the exploitation of smaller rivers and shallower reservoirs. Finally, even when the highest efficiency of small turbines has increased from around 88 to 93 % in two decades, research can help further improve this figure [5, 6].

4.2 Market and industry status and potential

Today's installed capacity in the EU-27 for hydropower is about 102 GW, without hydro-pumped storage. Approximately 90 % of this potential is covered by large hydropower plants. Over 21 000 small hydropower plants account for above 12 GW of installed capacity in the EU-27 [1, 6]. The SHP park is old: only 45 % being less than 60 years old and only 32 % less than 40 years old [6]. The annual net electricity production in the EU-27 during this decade has varied between 300 and 370 TWh, of which 13 % by SHP [1].

The techno-economic potential of hydropower electricity in the EU-27 is estimated to lie between 450 and 500 TWh/year. The largest remaining potential in Europe lies in low head plants (< 15 m) and in the refurbishment of existing facilities. The installed capacity of large-scale (and small-scale) hydropower for the EU-27, assumed by various sources, are: 100 GW (14.5 GW) in 2020 and 100 GW (15.5 GW) in 2030. Assuming that significant R&D and investment support for installing new capacities and refurbishment operations are made, which could result in 85 % of today's installed capacity being refurbished by 2030, the estimated maximum potential for large-scale (small-scale) hydropower plants in the EU-27 would rise to: 108 GW (18 GW) by 2020 and 112 GW (19 GW) by 2030 [7]. These capacities would generate about 8.7 (1.6) %, and 8.3 (1.6) % of projected EU gross electricity consumption by 2020 and 2030 respectively.

The estimated technically-feasible potential worldwide is 14 000 TWh, whereas the realistic potential could be 6 000 TWh/year (2 000 GW). IEA considers that only 5 % of the world small-scale potential is under exploitation and that the small-hydropower potential could therefore be from 150 to 200 GW.

At present, 38 GW of pumped hydro-storage capacity is installed across the EU-27 [1]. The retrofitting of existing facilities into storage schemes provides an important potential base for pumped hydro-storage development. World pumped-storage potential is approximately 1 000 GW or about half the realistic potential [5].

Three large European companies are acting in the large- to medium-scale hydropower market worldwide. These companies are currently facing a strong international competition from USA, China and India. The market for small hydropower is more accessible to small companies, with several European manufactures of the 60+ existing ones, holding a recognised industrial position worldwide leading to significant exports [6].

4.3 Barriers

Significant advances have been made in hydro-machinery during the past decades, with important prospects for further improvements. In contrast, the slow uptake of these new advances and inadequate research investments can be accounted for [7]. This is partially due to a general misperception that hydropower is a mature family of technologies, and therefore has no significant prospects for additional developments in the future. Furthermore, institutional barriers still exist that hamper its development, e.g. long lead times to obtain or renew concession rights, concessions locked to a holder that does not actually develop the scheme, grid connections, etc. Administrative procedures take from 12 months (Austria) to 12 years (Portugal), clearly sometimes too much [6].

The ratio of the pumped hydropower to total hydropower plants varies among Member States from zero to 92 %, which suggests barriers to pumped hydropower in certain MS. The implementation of the EU Water Framework Directive (WFD) in MS is expected to cause a decrease in hydropower production, in addition to not having been consistently done [6]. This has led to a significant reduction of new SHP installations and to higher costs, to the extent of being considered in some MS the main barrier to SHP development.

Meeting stringent environmental standards for water management can sometimes limit the plant capacity, but is also a driver for innovation and improved performances. A coherent policy framework and simplified administration procedures continue to be necessary. A further barrier is that small-scale projects face high transaction costs [3].

More efficient hydropower systems are required for which RD&D is vital, but hydropower is not seen as a political priority. The EU hydropower industry needs support to perform the required R&D work in areas such as: modelling for refurbishment operations;; turbines/pumps;; power electronics; and civil work developments to reduce their costs further; to ensure a high resource management with high environmental performance; and system efficiencies under variable loads. This is especially important for very low-head developments with a small enterprise-industry base (< 25 employees), having limited R&D and financial capacities. Worldwide, financing has been identified as the limiting factor in hydropower development, whereas policy changes and a lack of technical and managerial capacity are also important barriers [3].

4.4 Needs

There is a need for increased and focused R&D geared to harness the untapped hydropower potential in Europe (low head/very low head), to improve the resource exploitation of the existing generation base (refurbishment activities, multi-purpose schemes), to offer technological solutions to a changing market environment with a growing share of stochastic power (hydro-pumped storage), while ensuring a high degree of sustainability (compliance with the WFD) and to develop systems, procedures and devices that can help in alleviating the environmental impacts of hydropower. R&D should focus on the minimum water flow requirements under the WFD, and the effect on the environment when the water flow levels change rapidly as hydropower is increasingly used as balancing power in the electricity system.

Demonstrating the technology should be an integral part of these efforts in order to validate the technological developments at the system level, to exhibit the latest developments to attract investors and to get closer to the end-users. This development effort should go hand-in-hand with the set-up of innovative financing schemes to provide financial capacities for the EU industry to carry out these developments. MS need to tackle non-technological barriers in a definitive way, maybe by nominating “champions” or facilitators, who actively promote hydropower (especially SHP) and seek ways to overcome these barriers within their territory. Market support and simplification, and maybe harmonisation, of administrative procedures for concession rights and permit authorisations are complementary aspects to ensure the deployment of the outcome from the R&D programmes. In particular, such simplified procedures are needed for small hydropower projects and for refurbishment of existing facilities that do not require increasing reservoir volume.

4.5 Synergies with other sectors

Hydropower, especially large- and medium-scale hydropower at a system level, but also small-scale hydropower at a distributed generation level, e.g. wind/hydro-storage, can play a crucial role in the integration of other renewable energy sources by providing reserve, storage and balancing capacities for the European electricity grid. Synergies are also present in relation to tidal power and in particular, in the building of dams and the power conversion technologies (turbines and other equipment) used for tidal barrages. In addition, hydropower can be implemented in combination with other river activities (irrigation dams, water management, aquaculture, etc.) in multi-purpose concepts.

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5 GEOTHERMAL ENERGY

5.1 Technological state of the art and anticipated developments

Geothermal energy is energy stored in the form of heat beneath the surface of the earth and it is a very diffuse resource. It takes the form of: low underground temperatures for use by heat pumps; hot fluid (water, brine or, in the best case, steam, called in these cases *hydrothermal*); and heat stored in deeper, hot rocks [1]. The vast majority of geothermal resources are found nowadays as a mix of brine and steam [2]. Its energy content is described in terms of enthalpy or temperature. High (>180 °C) and medium (> 100 °C) temperature resources from hydrothermal reservoirs or from stimulated hot rocks (through enhanced geothermal systems, EGS) are used for electricity production. Low to medium temperature resources can be used directly as heat in district heating, for agriculture (greenhouses) or aquaculture, industrial process heating, and in spas. Very low temperature resources (< 30 °C) are used in ground-source heat pumps (GSHP) for heating and/or cooling industrial, residential or office buildings [1, 3]. Geothermal heat subsectors are therefore split into direct- and indirect-use; electricity production; and GSHP.

Two technological aspects dominate geothermal exploitation: the extraction of heat energy and its transformation into a usable form. The process of extracting geothermal energy can involve: (a) shallow underground piping, extracting heat through a vapour-compression cycle in GSHP; (b) deep (1 – 3 km), naturally-occurring geothermal fluids extracted from the earth, and later either re-injected or rejected; and (c) the injection of water through pipes at suitable hot-rock sites that is collected hot, via another pipe in EGS. The latter option requires the chemical or hydraulic stimulation of the hot-rock reservoir to enhance its permeability and thus production. An experimental EGS plant at Soultz-sous-Fôret (FR) started generating electricity in June 2008. A similar project near Basel (CH) was put on hold after resource stimulation caused seismic events [4]. A third EGS plant in Landau (DE) is producing 3 MW_e and 8 MW_{th} [5].

Technologies used for heat transformation into electricity are mostly linked to the temperature and pressure of the geothermal fluid. **Direct steam** turbines use the (rare) high temperature steam resources directly to generate electricity and result in the lowest power plant cost [6]. However, their open loop configuration raises concerns over environmental emissions and well management [2]. For the high-temperature mix of brine and steam, a **flash steam** plant is the most economical choice. The steam is first separated from the liquid and then expanded in a turbine. The hot brine could, however, be diverted to heat applications, in a technique known as cascading. **Double-flash steam** systems pass the hot brine through successive separators each at a subsequently lower pressure. The steam is directed to a dual-entry turbine with each steam flow flowing to a different part of the turbine. Advantages include increased overall cycle efficiency and better utilisation of the geothermal resource - but at an overall cost increase. **Binary cycle** technology separates, into two loops, the geothermal brine from a secondary or working fluid that is vaporised, then expanded through the turbine, condensed through an air- or water-cooled condenser, and pumped back to the heat exchanger to be re-vaporised. In a medium temperature (< 180 °C) reservoir, a binary plant is more efficient than a flash-steam cycle, and has better environmental performance [6], although they are more expensive for resources above 120 °C. Binary turbines can be of the Kalina or Organic Rankine cycle (ORC) technologies, as used in other industries, and are available from 60 kW to several megawatts.

Other than pure electricity generation, **geothermal combined heat and power** (CHP) is a natural energy-efficiency option wherever rejected heat from electricity generation, at temperatures below 80 °C, can be used, for example in district heating (DH) networks. Examples include Neustadt-Glewe (DE, 98 °C, 200 kW_e since 2003), Unterhaching (DE, 122 °C, Kalina power plant 3.2 MW_e since 2007 and since 2008, for electricity generation as well [4]. While direct heat use for balneotherapy (spas and

similar) is widespread, some rare examples exist of integration in district heating schemes, either supplementing or supplemented by gas turbines or biomass. Examples can be found in the Paris basin, Belgium, Germany and Hungary [4]. Use in agriculture to heat greenhouses is common throughout Europe, for example, for drying agricultural products [4].

Geothermal or ground-source heat pumps (GHP/GSHP) transform geothermal heat into useful space or water heating with the support of electricity from the grid. GSHP can be an open- or closed-loop, and can be used also for cooling and for single family houses, industrial, education and office buildings. Open-loop systems draw underground water for use as the heat source/sink and return the used water or send it to a drainage field. Closed-loop, also called earth-coupled, systems use a water and antifreeze solution, circulated in a ground loop of pipes, to extract heat from the earth. Ground loops can be built vertically or horizontally, the former is more expensive but used where space is limited. The depth of the loop pipe will vary with soil type, loop configuration and system capacity, from 2 metres for a horizontal loop, to 4 to 50 metres for ground-water wells and up to 250 metres deep for a vertical loop (borehole heat exchangers, BHE) [4]. GSHP is a mature industry although much stimulated by subsidies. The most efficient use of GSHP occurs when the required thermal rise is small. For this, the geothermal heat source temperature has to be relatively high (say 8 - 10 °C in winter) and the temperature of useful heat output to be relatively low, for example wall/underfloor heating that needs only 30 – 35 °C. The GSHP coefficient of performance (COP, ratio of output heat to input electricity) can reach 6 [7]. By comparison, heat-to-power conversion efficiencies vary between 7 – 20 % for hydrothermal fields and 7 – 12 % for EGS [8]. System efficiency analysis must deduct the parasitic consumption of electricity items, mostly pumps. A lower COP may be acceptable if a larger heat demand is covered, as in Sweden.

The state-of-the-art of reservoir assessment and management includes the crucial phase of reservoir assessment, i.e. reserve estimation and valuation. It includes both volumetric reserve estimation and valuation based on numerical reservoir simulation [8]. A number of techniques have been adopted to recover power from problematic brines, including the use of a crystallizer reactor clarifier and pH modification technologies. The use of either technique can add considerably to capital costs and to plant O&M cost. If pH modification is used for scale control, corrosion could also become more severe. Metallurgy of system components thus also becomes crucial and can add significant cost to the plant if more exotic materials such as titanium are used. Recent developments in adding enhanced evaporative cooling to air condensers in binary plant can improve summer efficiency of air-cooled binary plants by as much as 40 %. Compared to ORC, Kalina cycle systems that use a mix of ammonia and water as working fluid, reach higher efficiency.

The use of variable speed compressors and pumps in HP instead of fixed-speed components can yield up to 27 % efficiency improvement. New advances in double and even triple-pass absorption equipment allow for a cooling COP significantly above 1 to be obtained, and even at geothermal resource temperatures as low as 80 – 100 °C, absorption cooling may be the answer to meeting the needs of both greenhouse operators and providers of district energy service [6]. The COP for heat pumps is slowly increasing, ~ 2 % per year, i.e. by 0.1 [9]. In effect, HP technologies aim at increasing the seasonal performance factor (SPF, an index that takes into account COP and additional system-related consumption such as pumps) through more efficient materials and working fluids. The use of CO₂ as working fluid in HP is extensive in Japan but less common in Europe. The COP reaches above 5 and CO₂ does not have the environmental problems of freons or propane.

The trend in electricity generation is that flash systems, with their potential for higher efficiencies above 200 °C, become the standard for high-temperature resources. Binary systems are imposing over flash systems below 180 °C, and are poised to capture the largest share of growth [2]. In addition, binary power plants increasingly mix with flash systems in cascade configurations. EGS technologies

are increasingly being used to raise production at conventional sites [2]. An example is the reinjection of geothermal fluids to reduce concerns over the environment and to extend the reservoir's life. Two other significant trends are hybrid plants with biomass/biogas, and coproduction of geothermal energy and the metals present in brines to improve overall economics.

The geothermal energy R&D scenario is complex because most of the technologies are shared with other sectors, and therefore few R&D areas impact exclusively on geothermal energy. These include mainly deep-resource extraction and dealing with corrosive brine and materials for very-high-temperature, high-pressure sources. Binary plant R&D is also carried out in the oil and gas industry that, along with the telecommunications industry, uses it for remote applications. Geothermal heat pumps share much of its R&D with air heat pump technologies.

Several countries are focusing on *EGS*, including France, Germany, the UK and the Czech Republic and, outside the EU, the USA and Australia [10a]. Research aims at finding improved and newly developed methodologies able to map reservoir conditions suitable for EGS exploitation, in particular on the local scale; providing data integration (static and dynamic) and uncertainty analysis; and finding tools able to improve imaging between existing wells and performing real-time measurements [8]. The Icelandic Deep Drilling Project (IDDP) attempts to test the potential exploitation of sites that contain water under supercritical conditions at 4 – 5 km deep [10b].

Research on resource characterisation includes basic science on geothermal gradients and heat flow, geological structure, including lithology and hydrogeology, tectonics and induced seismicity potentials. Research on reservoir design and development includes fracture mapping and in-situ stress determination and prediction of optimal stimulation zones. Reservoir operation and maintenance includes research in reservoir performance monitoring through the analysis of temporal variation of reservoir properties [8]. For downhole pumps, an expected economical alternative to the current multi-stage pumps, research addresses the problem of the high temperature of the geothermal brine and aims at making commercially available for the sector.

Flash technology R&D focuses on increased efficiency and improved resistance to corrosion from brine and other contaminants in the geothermal resource. Some research focuses on the coproduction of silica and other minerals from geothermal brines. Initial estimates from Salton Sea geothermal fields (US, 2000) placed the market value of extracted silica at USD 84 million a year. The facility is designed to produce 30 000 metric tonnes of 99.99 % pure zinc annually at a value of approximately USD 50 million (Clutter, quoted in [6]). Binary cycle research explores the use of ammonia and other more environmentally-friendly replacements to hydrocarbons and freons (R11/R22) [6]. ORC R&D focuses on new heat transfer fluids to improve efficiency and on improved manufacturing capabilities to advance modularity benefits. Kalina cycle R&D focuses on reducing costs to make the technology competitive with current ORC alternatives. Heat exchanger research focuses on its protection, at a reasonable cost, against corrosive brine. Related energy- storage research includes hot, cold, hot and cold combined and, in particular high-temperature heat storage. R&D also focuses on hybrid systems that combine geothermal with solar energy and biomass, for heating & cooling, and their integration in the low-energy house concept.

In the geothermal heat pump sector, the R&D focus is on: the development of components easy to connect and disconnect from the surface; advanced control systems; natural and more efficient working fluids; single-split and multi-split heat pump solutions for moderate climate zones (Japan); the use of a second heat source (hybrid heat sources), increased efficiency of auxiliaries (pump, fan) and change in the control of the systems (Sweden) [11].

Both increased application and innovative concepts for geothermal energy focus on cooling, agricultural uses, industry, de-icing and snow melting on roads and airport runways. Demonstration projects focus on buildings integrating heat pumps, e.g. in the foundations.

Geothermal energy is not without environmental problems and they need careful attention. In addition, they have to be weighted against its environmental benefits. In Milos, Greece, sulphur smell and silica scale on car windows were two of the three factors that finally forced operators to abandon a pilot plant after only 2 years of operation, as it had completely lost acceptance by the local population [8]. The issue of groundwater protection (because of the lubricant pollution at incorrectly-positioned or badly-drilled boreholes) can badly affect a project. In December 2006 and January 2007, reservoir stimulation (water injection to widen cracks) on a geothermal plant in Basel caused several earthquakes up to 3.4 on the Richter scale and up to 2 000 reports of damage [10c].

Capital costs for conventional geothermal electricity are in the 1 000 – 3 800 €/kW range, resulting in 40 – 80 €/MWh [2, 8]. EGS investment costs are much higher given the experimental nature of the technology (10 000 – 26 000 €/kW) and result in a cost of 170 – 350 €/MWh. Capital cost for heat supply from conventional sites is in the range of 100 – 300 €/kW_{th}, resulting in a cost of 4 – 7 €/MWh_{th}. Heat supply costs from EGS are only speculative at one tenth the EGS electricity costs [8]. The single item that has the highest impact on costs is drilling, typically 30 - 50 % of total development cost for electricity generation [6]. Well costs can vary from a few tens of thousands to several million euro for high-temperature wells for electricity generation. Piping costs vary from 200 to 6 000 €/metre in highly developed urban areas [6]. Drilling two boreholes, known as a doublet, to a depth of 3 000 metres can cost up to 14 million euro [10c]. Insurance premiums can cost up to 25 % of the sum insured. Over half of the total production costs over the lifetime of the project are expenses associated with the well field. Up to 50 % or more of the wells might have to be replaced over the course of the project, possibly increasing levelised electricity cost by 15-20 %.

The installed cost of heat pumps vary between 1 000 and 2 500 €/kW for typical domestic facilities of 6 - 11 kW, and between 1 700 and 1 950 €/kW for industrial or commercial installations in the 55 – 300 kW range [12]. Capital costs depend greatly on the ground exchanger layout, whether horizontal or boreholes. Data from Greece [9] suggests capital costs between 1 200 and 1 500 €/kW_{th}, electricity and maintenance costs of 28 €/MWh_{th}, giving total costs of 48 €/MWh_{th} (including capital amortisation over 20 years with 5 % cost of borrowing money). This has to be compared with diesel oil: 72 €/MWh_{th}; natural gas between 58 and 65 €/MWh_{th} and air source heat pumps of 60 €/MWh_{th}. Of the estimated EUR 81 billion (USD 120b) invested in renewables worldwide in 2008, around 6 % (4.9 €/m) were directed to geothermal heat and power [13].

The system availability for a geothermal energy plant can reach 95 %. A modern electricity plant can reach a 92 % load factor (8 000 full-load hours), whereas actual national figures vary from 60 % to 85 % [14]. The mode of operation determines these load factors: whereas most plants are operated as base-load supply, thus reaching high load factors, the depletion of the reservoir may force peak-load operation [6], reducing the load factor accordingly. Heat pumps have a lower actual factor at around 20 % [15, 16], whereas other heat uses reach load factors of 20 to 60 %.

5.2 Market and industry status and potential

Geothermal power plant supply is currently dominated by a small group of established leaders including Mitsubishi (MHI), Fuji Electric, Toshiba and Ormat (92 % of the binary plant share), which together have supplied nearly 80 % of the global geothermal power plant market. The drilling market is shared between three groups of suppliers. Oil and gas drillers (Halliburton, Baker Hughes, Schlumberger), which held the largest share in 2004 – 2008 (42 %), now have 28 %. Specialised geothermal drilling firms (Iceland Drilling, Themasource) have gained a market share of 44 % in 2009.

Geothermal developers (Ormat, Enel, Mighty River, Vulcan Power) maintain a stable 28 % (2009) vs. 27 % in the period 2004 - 2008 [2].

The installed geothermal electricity capacity in the EU in 2008 was 850 MW, mainly in Italy (810 MW). However, not all the installed capacity is running and, for example, the actual running capacity in Italy is 671 MW, 82 % of installed capacity. Beyond the EU, the US has 3 000 MW, the Philippines 2 000 MW and Iceland 573 MW installed [17]. In total the world installed capacity reached 10.5 GW in 2008 in a mix dominated by flash technology (single-flash, 45 %; double-flash, 14 %), and followed by dry steam (25 %), binary plant (9 %) and combined cycle (7 %) [2]. After an 11 % growth in installed capacity during 2008 [18], GSHP accounted for an estimated 9.7 GWth [18, 19]. Capacity for direct heat use was 2.5 GWth in 2007 (2008 figures not available). Globally GSHP reached 30 GWth of installed capacity by the end of 2008, with other direct heat uses reaching an estimated 15 GWth. At least 76 countries use direct geothermal energy [13].

Gross geothermal electricity production in the EU reached 5.77 TWh in 2007 of which 96 % is in Italy. EU-27 production increased 20 % in the 8 years to 2007, compared to a 370 % increase of wind electricity [20]. Global geothermal electricity production reached 57 TWh in 2007 [14]. Useful heat production in the EU reached 17 TWh from GSHP [18, 19] and 9.2 TWh from direct heat uses in 2008, totalling 26.2 TWh. Worldwide, in 2005, direct-use geothermal heat accounted for 76 TWh in 76 countries [21] - no updated figures are available.

Some EU countries have significant conventional electricity potential including Greece (500 MW) and Hungary (72 MW), whereas for the EU-27 as a whole the potential was estimated at 3.56 GW [2]. Global installed power capacity is expected to increase to 11.4 GW by 2010 and, if projections are realised, 16.8 GW of installed capacity will be distributed in the medium term between the US (35 %), Philippines (16 %), Indonesia (9 %), Mexico and New Zealand (7 % each), and Iceland and Italy (5.4 % each) [10a, 17]. Some scenarios suggest at least a tripling of the installed capacity of 24 to 40 GW by 2020 [2, 22], most of the growth being in North America and South East Asia, with a gradual change from flash technology towards binary plant. Figures for the long-term potential vary very significantly from 140 GW [2] to 5 900 GW [10d]. GSHP's potential expansion to large buildings (commercial, residential, etc.) and other markets is significant, as highlighted by the very different penetration of the technology in different EU MS. In addition, the residual thermal energy stored in geothermal brine after heat exchange in a binary cycle ($T_{\max} \approx 75 \text{ }^{\circ}\text{C}$) can be used for district heating in high-density areas, hot water supply, and low-temperature industrial processes, e.g. in the food and textile industries. Also the residual heat of the condensed binary liquid after conversion in the turbine ($T_{\max} = 35 \text{ }^{\circ}\text{C}$) can be put to other uses in, in particular, the agricultural sector, e.g. greenhouses, aquaculture technology [8].

5.3 Barriers

The key barriers are the high cost of drilling and a high risk that heat and electricity production does not reach the projected objectives. Success ratios for exploration wells may be as low as 20 % and no higher than 60 %. The industry competes for drilling subcontractors with the O&G industry, which can have an undesirable impact: for example, when the price of oil and gas is high, the cost of drilling for geothermal projects increases. By spring 2009, drilling costs were down 40 - 50 % for oil and gas, although these cost reductions do not necessarily translate to geothermal because of the need for geothermal-experienced crew [2]. Two other important barriers to geothermal deployment continue to be a lack of appropriate legislation, such as on resource ownership, and a complex licensing system. Financial incentives and in particular RES-E support schemes across the different MS are inconsistent. Currently 13 MS offer geothermal electricity feed-in-tariffs, ranging from 25 to 270 €/MWh [2], which in some cases are inadequate and unattractive. A complex permit and development legal framework and administrative procedures for geothermal exploitation means long lead times for obtaining the

necessary permits and licences and uncertainties for investors. Lack of acceptance, due to negative impacts of geothermal exploitation, e.g. visual and odour-related impacts, hinders large-scale deployment. Fragmentation of existing knowledge reduces progress in the sector and technological and environmental knowledge gaps increase the financial risk. Enabling technologies, such as binary cycle and improved exploration and drilling techniques, can improve the economics of geothermal energy and need to be developed accordingly. Finally, there is a shortage of a qualified work force for the sector.

5.4 Needs

An effective policy is needed to address specific legal and financial measures in the geothermal energy sector, particularly regarding administrative issues and funding of risk insurance. There is a need for clear definitions of ownership, access rights and environmental regulatory conditions. There is also a need for coherency in the various financial support mechanisms already in existence in different MS and a need to create additional support instruments, both financial (incentives) and regulatory (standards). With regards to the administrative barriers, legal frameworks and regulations concerning the ownership and exploitation of geothermal energy must be clarified, including the harmonisation of permit procedures. Increasing the acceptance of geothermal energy will require education and awareness campaigns at all levels, as well as R&D to minimise the environmental impacts of geothermal exploitation. There is also a need for RD&D support to enable technological advancement and deployment of emerging concepts, e.g. EGS, hybrid systems, as well as for the exploitation of cascading uses. EGS needs the establishment of a number of “lighthouse” plants across the EU. International research collaboration and centralisation of existing knowledge and data in geothermal and related sectors, inside and outside of the EU, will be critical for exploiting synergies between the sectors. To assure a sufficiently qualified work force for the sector vocational training and certification programmes are required.

5.5 Synergies with other sectors

Synergies with the oil and gas industry include geological knowledge and expertise, and the joint exploitation of geothermal/hydrocarbon co-production and geo-pressured resources. Techniques borrowed from the O&G industry are currently being used to pump cold water into the hot dry rock to create predictable fractures that will allow a large volume of fluid to move between wells without allowing the fluid to drain out of the artificial reservoir [2]. In the carbon dioxide storage sectors, there is a need for similar types of information for emerging geothermal energy technologies, e.g. EGS, which could provide synergies. At the same time, the potential use of a single site for geothermal energy or carbon dioxide storage could result in competition between the two sectors. Synergies with the biomass sector may be possible from the cascading use of geothermal heat in biomass processes. Geothermal heat pump technologies are strongly linked to air-source heat pumps, and here synergies affect working fluids, materials, etc. GSHP would help to reduce peak electricity consumption and synergies with grid management and (maybe) smart-grid projects are possible. Research on the Kalina cycle would not only benefit geothermal but all of their many industrial uses, remote applications, etc.

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6 OCEAN ENERGY

6.1 Technological state of the art and anticipated developments

The exploitation of the energy of the ocean started with a 240 MW tidal barrage scheme at La Range (FR) in 1966, and all but stopped there. Some early experience of wave energy exploitation included a 500 kW shoreline scheme by Wavegem at Islay (UK) and a similar Oscillating Water Column (OWC) device at Pico (PT). One-off tidal current schemes have been deployed in the UK since 2003 (Marine Current Turbines) but they, as well as the remaining ocean technologies, are at an early stage of development and no devices have entered series production [1].

The main forms of ocean energy are waves, tides, marine currents, salinity gradient, and temperature gradient. They are used largely for the generation of electricity although some secondary uses exist, including desalination and compressed air for aquaculture. Wave energy is mostly derived from a transfer of wind energy to the surface of the ocean; it is manifested as the average height of waves [1] and is measured in terms of watts per metre of wave front (W/m) [2]. Tidal energy is the potential energy between the high and low tides and is cost-effective when the “usable head” is five metres or more [3]. The large mass of moving water in tidal and other marine currents contain kinetic energy that can mostly be captured by means of wind-turbine-like technology. The velocity of tidal currents (not necessarily other currents) varies throughout the day in a pattern similar to the height of the tide, and a minimum average speed of 1.5 m/s is necessary for a viable energy scheme [4]. Salinity gradient power is based on differences in chemical potential between saltwater and freshwater [4]. Temperature gradient energy utilises the difference between the warm surface of the ocean and the colder layers underneath, up to 15 °C, which can be used in what is termed ocean thermal energy conversion (OTEC) [5].

Capturing the energy from waves is a complex issue because it is very location specific. Changes in wave energy occur in hours, minutes and even between waves [5], making wave even more variable than wind. However, the energy transferred from wind creates waves after the wind has gone, thus making wave energy a natural storage of wind energy [6]. To cope with this variability power take-off systems attempt to incorporate storage systems to buffer and smooth their power output. Wave devices can be distinguished according to the location of the power plant to the seabed depth and the shoreline, near to shore (< 20 m depth) or offshore (> 40 m depth) [7]. A large number of devices and designs are currently being studied and/or developed. Up to 25 countries, led by the UK, are involved in the development of more than 50 types of wave energy converters [5] of which only a few are at a full-scale prototype stage. Most of them rely on the physics of two inertial masses reacting against each other in such a way that power can be generated between the opposing forces [8]. This principle is mainly applied to wave energy extraction as: oscillating water columns (OWC) which generate electricity from the wave heave pressure effect in a shaft; absorber systems, floating structures that absorb energy from all directions by virtue of their movement at or near the surface of the water; and overtopping devices, floating reservoirs partially submerged where a head of water is created and further used to run hydropower turbines. Regarding power take-off, six options currently exist: air turbine; close-circuit oil hydraulics; direct (linear generator) drive; low-head water turbine; water pump; and open-circuit water hydraulics, e.g. Hose Pump [8]. Rated power capacities of a single system are of the order of 70 kW to a few MW. Several units can be linked, e.g. to reach several MW, to create a wave energy farm. Average capacity factors for wave power installations are around 3 000 – 3 500 full-load hours per year [9], while for shore-line technology this can be around 2 000 full-load hours [7].

Tidal potential energy is converted into electricity in large, dam-like structures (barrages) across the mouth of a bay or estuary in an area with a large tidal range. The sea level changes with the tides and the potential energy is created as a difference in water height across the barrage, and extracted by

means of turbines in a similar way to low-head hydropower schemes. The dam can be built of diverse materials such as earthen dams, for example in China, and consists additionally of dikes connecting with the natural embankment and a sluiceway. A passage way for fish can be provided [3]. Power can be delivered twice or four times per day on a highly predictable basis, and power generation can even be synchronised with peak-demand periods even if these do not coincide with tide peaks [3]. This is the only commercial ocean technology currently existing, but its expansion is unlikely due to its environmental impact and high capital cost [7]. Capacity factors expected for tidal barrages varies from 1 800 to 3 000 full-load hours whereas the actual figure for La Range is 2 100 hours [10]. The environmental impact of tidal barrages is of such importance that one of the best sites in the world for a prospective barrage, the UK's Severn estuary, was never developed and its project approach is changing now to a "tidal fence", i.e. a non-tide-blocking barrage-like structure that would extract energy from the tidal current [11]. Tidal barrages could also contribute pumping capacity operating between two lagoons, thus contributing to an increased renewable energy component on the electricity mix and to grid stability [10].

The energy of tidal and other marine currents can be extracted using devices placed directly "in-stream" that generate energy from the flow of water. Technologies include horizontal- and vertical-axis turbines, venturis and oscillating foils, which all can float or be anchored to the seabed. The energy available is proportional to the cube of the current velocity at the site. Thus, in a similar way to wind energy, the power that can be generated by a turbine is roughly proportional to its area, and the higher the flow velocity the higher the power output. Energy extracted is also proportional to the density of the medium, and being water around 900 times denser than air, the turbine area necessary to provide the same power in water is much smaller. Horizontal-axis turbines are aligned parallel to the current flow and include a variety of approaches including ducts, variable pitch blades and rim generators. These axial-flow turbines generally use a power take-off mechanism involving a generator coupled to the turbine shaft either directly or via a gearbox. Their main difficulty is access to the devices for maintenance. Vertical-axis turbines have more possibilities of development for ocean currents than for wind as they work well with variable fluid flows and can have a larger cross-sectional turbine area in shallow water than is possible with horizontal-axis turbines [5].

Due to solar heating the amount of energy available in the temperature gradient between hot and cold seawater can be substantially larger than the energy required for pumping the cold seawater up from the lower layers of the ocean. The warm water from the surface is used to boil a working fluid (or, in open cycle systems, the seawater itself under low pressure), which is then run through a turbine and condensed using cold seawater pumped up from the depths [4, 5]. Salinity gradient power can be extracted either via a process known as "pressure-retarded osmosis", where the pressure induced by the movement of water across a membrane is used to run turbines, or by using freshwater upwelling through a turbine immersed in seawater. A further technology involving electrochemical reactions is also in development [5]. Temperature and salinity gradient energies are very unlikely to contribute any significant part of energy supply in Europe by 2020 and therefore are not treated hereafter.

Robustness and reliability under extreme weather conditions is the main challenge that ocean energy devices face, and significant development will still be needed [1]. In R&D, basic research areas include the understanding of wave behaviour/wave-stream flow and hydrodynamics; the physical and environmental interaction of conversion process with wave, tidal current, temperature gradient and salinity gradient resources; offshore network interaction with ocean energy plants; and new materials for efficient osmotic processes [1]. Wave energy requires that ocean measurement and forecasting techniques over long distances are developed and implemented to improve predictability of energy production. In addition focus is on moorings; structure and hull design methods; power take-off systems; deployment methods; and wave behaviour and the hydrodynamics of wave absorption [1].

Public support in some Member States addresses the creation of offshore testing and demonstration facilities connected to the electricity grid. Specific development zones for at least wave power are being developed, e.g. European Marine Energy Centre (EMEC) UK, or planned for building in the near term, e.g. Biscay Marine Energy Platform (BIMEP) ES and elsewhere in PT, IE, FI and IT. European companies are active in shoreline-, near-shore-, and offshore- based devices. Among the different converters capable of exploiting offshore wave power, a group of three Pelamis wave energy converters – an attenuator technology by the UK firm Pelamis Wave Power - was deployed in Portugal in 2008 although it was later brought to shore due to a bearings-related problem [12]. Other wave energy systems based on different technologies developed by European stakeholders are being tested under real sea conditions.

Basic research on tidal stream current systems focuses on areas such as water stream flow patterns and cavitations. Applied research examines supporting structural design, turbines, foundations and deployment methods [1]. Research efforts on turbines and rotors will need to focus on cost-efficiency, reliability and ease of maintenance, particularly in developing components, e.g. bearings that can resist hostile marine environments. Control systems for turbine speed and rotor pitch will also be important to maximise power output [1].

Industry is attempting to escape from the trap of site-specific projects by focusing development on modular systems. In the same way that wind turbines are deployed in wind farms, wave and ocean current devices will be linked in clusters thus achieving strong manufacturing economies of scale. Even for tidal barrages, there are proposals for modular structures [10].

Due to their stage of development, the cost of ocean energy devices has not changed significantly since the issue of the last Technology Map in 2007 [7]. For current wave prototypes costs are of the order of 4 500 to 13 000 €/kW [1, 13]. This leads to a cost performance average estimate in the range of 11 to 26 c€/kWh [1, 13]. Initial capital investment costs of future first commercial units are estimated to be of the order of 2 500 to 7 000 €/kW [7]. One of the causes of these high cost levels is, as highlighted above, that wave power is very site- and technology-specific. However, because most of these technologies are still at the pre-commercial or RD&D stage current costs are not very informative.

The cost of the only tidal barrage power scheme currently under construction, the Sihwa tidal power plant in South Korea, is expected between 700 and 1 200 €/kW, and this figure does not include the cost of the barrage [1, 14]. Barrage costs can vary between EUR 14 and 70 million per kilometre. Estimated costs by IEA [1] vary between 1 500 and 3 500 €/kW for tidal barrages, and between 5 000 and 8 500 €/kW for tidal current technologies. Tidal barrage estimate of future costs (2030) do not vary much whereas tidal current technologies could achieve a 20 – 25 % reduction, and wave energy technologies up to 66 % [1]. There is no experience in operation and maintenance costs other than for the La Range scheme. The economics of ocean systems will also be improved if they are associated with offshore wind turbines or other marine devices: wind turbines installed in a tidal barrage or current turbines sharing the monopile foundations with wind turbines.

6.2 Market and industry status and potential

In addition to La Range, a tidal barrage system exists in Canada and a further scheme should be finished by the end of the year: the 254 MW Sihwa scheme in South Korea. Interestingly, this scheme is not building a barrage but using one built in 1994 for irrigation purposes. Wave systems are coming on-line at a rate of less than 10 MW per year and are all demonstration or pre-commercial plants.

Globally, energy production from ocean energy other than tidal barrages is not significant. Tidal energy generates around 500 GWh annually at La Range [10] and 31 GWh in Canada [15].

The potential for wave energy depends on average wave heights. The wave potential tends to be higher towards the polar regions, but is site-dependent [1]. The economic and technical electricity production potential for ocean wave power estimated for Europe varies from 150 to 240 TWh/year [7] to above 1 000 TWh/year [6]. In the EU-27, the Atlantic arc from Scotland to Portugal is the most favourable area in terms of resources. The installed capacity of wave energy, with respect to the baseline, is 0.9 GW in 2020 and 1.7 GW in 2030. The estimated maximum potential for wave energy in the EU-27 is up to 10 GW by 2020 and 16 GW by 2030. These capacities would generate 0.8 % and 1.1 % of the EU-27 electricity consumption projected by 2020 and 2030 respectively [7]. Ocean current resources in Europe were estimated between 15 and 35 TWh/yr with 10 GW installed capacity [16].

Globally, the estimated theoretical resource is highest for wave energy (8 000 – 80 000 TWh/yr), followed by OTEC (10 000 TWh/yr), salinity gradient (2 000 TWh/yr) and ocean currents (800 TWh/yr) [17]. For tidal energy the potential is estimated at 1 000 – 2 000 TWh/yr [10]. Note that other sources are quite more pessimistic and estimate the global technically-exploitable potential for wave energy at 1 400 TWh/yr, for ocean currents at 450 TWh/yr and for tidal energy at 380 TWh/yr in 160 GW of future installed capacity (World Energy Council quoted in [16]). It has to be noted that the potential for tidal energy is heavily dependent on technological advance. Most calculations assume that potential exists only where the tidal range is five metres or more. However, the development of low- and ultra-low-head turbines makes possible the use of a lower tidal range, thereby greatly increasing the potential generation [3].

A new industry is currently being created. This sector provides opportunities for spin-offs for offshore activities (e.g. oil industry, ship building).

6.3 Barriers

Ocean energies other than tidal barrages are at their pre-commercial stage. Pilot projects need to be relatively large-scale if they are to withstand the roughness of the marine environment [1]. This results in high costs and commercial risks. But probably the main barrier to wave and tidal current energy development is the lack of one or a few dominant conceptual designs. This forces governments and R&D programmes to invest in a large variety of designs which divides effort and reduces the achievable results. Government support programmes at times do not match the actual requirements of a nascent sector and sometimes address the wrong point of development [8]. Another important barrier is the current lack of cost-competitiveness due to the initial state of development. Appropriate grid infrastructure and connections will be important for further development. Grid connections to onshore grids can also be problematic, as in some cases the grid is too weak to absorb the electricity production from wave energy power stations. In addition, licensing and authorisation costs and procedures are very high and complex. It can take several years to obtain the permit from administrations not prepared to tackle ocean energy, with costs up to one million euro. A lack of dedicated or experienced administrative structures causes long permit procedures. Maintenance and plant construction costs are also very high, especially in the start-up phase. There is currently little experience on maintenance for offshore facilities. For the time being, offshore infrastructure from oil industry (ships, platform equipments) is used to carry out these operations which turn out to be costly. Equally, there is a need for specific engineering capacities. Technology learning is currently slow and expensive, and most of the engineering know-how is from the offshore industry. The lack of tailored engineering expertise can result in oversized equipment and, consequently, increased capital investment cost.

Another important barrier is the lack of long-term strategic development and deployment planning that could help in securing industrial investments. Fully-fledged development and operating costs are beyond the capacities of small and medium enterprises (SME's), and only a few large industries are already involved. Environmental issues form a key barrier preventing the development of tidal barrages and, in general with all ocean energy, the environmental impact assessment requirements can

be disproportionate for novel technologies. Finally, with the advent of the deployment of ocean energy technologies, coastal management is a critical issue to regulate potential conflicts for the use of coastal space with other maritime activities [7, 18].

6.4 Needs

At this stage of development, ocean energy technologies entail significant financial risks and infrastructure investment costs. Public intervention is essential to share the risks between private and public stakeholders, and to shorten and make more efficient the permit process. This is being done in the new testing and development platforms, e.g. EMEC and BIMEP. It is essential to install the first generation capacity to acquire experience on performance and maintenance, and attract investors. To do so, the design and implementation of support measures that are appropriately targeted and based on feed-in tariffs, capital investment incentives, etc., are crucial. Even more, planning of long-term strategic development and deployment is needed on the side of the Member States and the EU.

More R&D support is necessary that can tackle establishing standards, develop energy production forecasting and design tools, dedicated reference testing centres, and develop specific engineering capacities to accelerate the technology learning curve. Along the same line, the ocean energy community needs to acquire a sufficient critical size. Information exchange and coordination efforts among the stakeholders must be fostered. It is equally important that the expert wave energy community trains a new generation of scientists and attracts people from different horizons such as offshore wind energy to foster know-how transfer. With a large expansion in ocean energy anticipated, the requirements for grids will become acute. In many cases, there is no grid available in the nearby onshore area for connection. On the Atlantic arc, significant investment will have to be made and there are already examples of such grid upgrade projects (UK, Beaulieu – Denny overhead high voltage line being upgraded from 132 to 400 kV) [18].

6.5 Synergies with other sectors

The field that is likely to share the most synergies with the ocean energy sector is offshore wind in areas such as maintenance, maintenance access to the assets, moorings, foundations, joint investment on export electricity lines and others. New floating wind turbines will have synergies with floating wave or ocean current devices. Offshore wind turbines and ocean energy devices might share their foundations, e.g. a monopile structure shared by a wind turbine and a current turbine of the SeaGen type [19]. In addition, there are synergies with the offshore oil and gas industry, and the hydropower sector. Technology learning in the field of ocean energy is expensive. The costs and efforts can be reduced by fostering cross-sectoral knowledge and transfer of know-how. As an example, joint activities with the hydropower sector in research and development of low-head turbines, could reduce costs and enable lower tidal ranges to be used economically. Mixed schemes of offshore wind with pumping-tidal schemes would increase availability and reduce the variability of the former.

Synergies of tidal energy with non-energy sectors (which would also contribute to social acceptance) could include the creation of long sandy beaches, sailing or fishing harbours, tourism or industrial areas nearby. Tidal basins could partly increase the land areas and protect the shores from exceptional high water events [10].

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7 COGENERATION OF HEAT AND POWER

7.1 Technological state of the art and anticipated developments

A modern fossil-fuel power plant transforms about half the primary energy content of the fuel into electricity (only one third in older power plants) and rejects the rest as “waste” heat. Cogeneration, or Combined Heat and Power (CHP), uses a part of that heat to satisfy a heat demand that would otherwise be satisfied by some other energy generation process. Hence CHP improves the overall efficiency of fuel utilization and provides primary energy saving in comparison to the conventional technologies of separate power and heat production.

Various technologies are used for power generation (“prime movers”) in existing CHP systems and co-produced heat is used in different forms and on different temperature levels. Therefore, energy conversion efficiency varies considerably among different CHP systems. The average overall efficiency in EU CHP industry is about 55 %, of which the average electrical efficiency is less than 20 % [1, 2, 3]. However, overall efficiency of newly installed CHP systems varies from 60 to 90 % of which the electrical efficiency is about 30 to 55 % [4, 5, 6].

For CHP to achieve high total efficiencies, their electrical efficiencies will be lower than what might be expected from the same fuel, equivalent-size, electricity-only power plants, and this is unlikely to change. Nevertheless, further increases of electrical efficiency of CHP systems are expected, particularly for gas turbines, but also internal combustion engines and steam turbines. At the present time natural gas is the preferred fuel which can be used in all types of equipment, but combined-cycle gas turbines (CCGT) and gas turbines are expected to be the predominant future technology for large scale units. Coal and solid biomass are mainly, although not necessary, restricted to steam turbine CHP units.

More recently, attention has also been given to the development of small-scale CHP systems because of the large potential market in the residential and commercial sectors. Small CHP units of 100 kW_e and above represent a steadily growing market with features rather similar to large units. Some of the recent reports from Member States on CHP potential have shown that decentralised CHP systems save more primary energy, when compared to the reference values, than large centralised CHP systems (mainly with steam turbines) [7, 8]. The development of stationary fuel cell CHP is attracting particular interest because its electrical efficiency is high compared to other options (i.e. 34 – 50 % electrical and up to 90 % overall efficiency) and they have some other operational advantages (noise, size, etc.) [9, 10]. Significant progress is expected with molten carbonate and solid oxide fuel cells (MCFC and SOFC) for industry and commercial applications, and polymer electrolyte membrane fuel cells (PEMFC) for households (micro-CHP).

Micro-CHP units, particularly below 20 kW_e, are still in the R&D and demonstration phase (Stirling engines, organic Rankine cycle, micro-turbine), while only internal combustion engines of similar size are already on the EU market. Unfortunately, the rate of progress with the kilowatt-size CHP units seems disappointing in comparison to expectations of several years ago. A trial on Stirling engine-based units had mixed results in terms of energy savings and the situation seems to be not dissimilar regarding the development of micro-turbine CHP. Electrical efficiency of such units is still low and improvements are expected, e.g. up to 30 % for micro-turbines and 25 % for Stirling engines [7, 9, 11, 12].

To achieve high conversion efficiency, CHPs are principally driven by heat demand. Therefore, load factor varies significantly for different applications and regions, from about 1 000 to 6 500 h, and on average for EU is approximately 3 600 h [1, 2, 3, 13, 14].

Specific capital cost for a typical state-of-the-art CHP using solid fossil fuel varies from about 1 900 €/kW_e for large units (250 MW_e) to 2 400 €/kW_e for medium sized (40 MW_e) [15, 16, 17]. Capital cost for gas fired CHP is in the range from 1 100 €/kW_e for large CCGT units (100 MW_e), 800 - 1 200 €/kW_e for medium sized gas turbines (10 - 50 MW_e) and 1 000 €/kW_e for reciprocating engines (3 MW_e) [5, 6, 15, 16, 17]. These CHP systems are based on mature, reliable and proven technologies, and significant further cost reduction cannot be expected in this segment [17, 18, 19].

The specific capital costs of biomass CHP systems vary from 2 400 to 6 000 €/kW_e [11, 14, 15, 17]. Capital cost of these systems, however, is expected to be gradually reduced by 10 – 15 % until 2030 [11, 17]. Capital cost for small scale- and micro-CHP is in the range 1 700 - 2 700 €/kW_e, whereas for fuel cell based CHP is from 4 000 to 12 000 €/kW_e for industrial units and up to 20 000 €/kW_e for small household applications [5, 6, 9, 12]. Since the latter is the price for early field test, a significant price decrease is expected for the deployment phase.

7.2 Market and industry status and potential

The installed capacities of CHP for the EU27 assumed in the baseline scenario of the DG TREN publication “*European Energy and Transport: Trends to 2030 - Update 2007*” [20] are 160 GW_e in 2020 and 170 GW_e in 2030. The estimated maximum potential for CHP in the EU-27 is up to 185 GW_e by 2020 and 235 GW_e by 2030 [9]. This represents about 19 % and 22 % of the projected EU electricity generation by 2020 and 2030 respectively.

Presently, installed CHP capacity in the EU-27 is about 100 GW_e, which generates about 11 % of total electricity generation [1]. More than half of the CHP electricity, about 57 %, is produced in plants where CHP is main activity (mainly district heating plants), whilst auto-producers (mainly industry) account for the remaining CHP generation. Nine countries account for 76 % of the total electricity generation from CHP in the EU-27, namely: Germany, Italy, Netherlands, Finland, Poland, UK, Spain, Denmark and France [1].

As a fuel, natural gas at almost 40 % dominates the CHP market, followed by solid fossil fuels at 35 %. Natural gas seems to be the fuel of choice for new CHP plants in the majority of countries, while the use of coal is declining. Renewables, mainly biomass are becoming increasingly important having reached 12 %, although this share remained almost unchanged over recent years [1].

CHP systems have significant penetration in EU industry, producing approximately 16 % of industry’s final heat demand. The baseline assumes further growth in this segment, to about 23 % by 2030. Important CHP applications are district heating and cooling (DHC) systems, where 68 % of heat supply is CHP-based. Here the baseline does not foresee any future increase. Key factors of CHP development on the industrial market will be availability and price of natural gas which is the preferred fuel for most new industrial CHP systems. Significant potential over baseline growth for industry’s heat demand is not assumed, but additional potential to the baseline is expected in the DHC segment through conversion of heat-only boiler systems to those of the CHP type (up to 80 % contribution by 2030) [9].

An important growth is assumed in biomass-based CHP, mainly in DHC but also in industry. The estimated potential for the installed capacity of biomass CHP in the EU-27 is about 40 GW_e by 2020 and up to 55 GW_e by 2030, assuming that CHPs represent approximately 2/3 of the total installed capacities of biomass-based power plants. These CHP capacities would generate about 4.5 % and 5.5 % of projected EU electricity generation by 2020 and 2030 respectively [9].

Growth is also assumed in distributed power generation, but mainly after 2020. The main interest in micro-CHP will be focused on the “single household” type of unit in which the power output is a few

kilowatts. However, this potential could be limited by competition from district heat CHP. While fuel cell-based CHP are not assumed in the baseline, the estimated maximum potential for such CHPs in the EU-27 is up to 9 GW_e by 2020 and 15 GW_e by 2030 (assuming mainly natural gas-fuelled units). This represents about 1 % and 2 % of projected EU electricity generation by 2020 and 2030 respectively [9].

The estimated maximum potential for fossil fuel CHP in the EU-27 is up to 150 GW_e by 2020 and 200 GW_e by 2030, which includes distributed power generation. This represents about 15 % and 18 % of projected EU electricity generation by 2020 and 2030 respectively (considering only generation in cogeneration process) [9].

It should be noted that the described CHP potential should be read as common potential at the EU27 level, while relative penetration of the technologies at the Member States level may vary from this average, depending on the specific structure of power sector and heat demand.

Finally, globally installed CHP capacity currently stands at about 330 GW_e and could reach more than 500 GW_e in 2015 and over 900 GW_e in 2030 [17]. The EU has a strong industrial base in manufacturing CHP plants, so given that these companies export CHPs worldwide and global growth is forecast, EU manufacturers should remain a key player in the CHP market in future.

7.3 Barriers

The growth of CHP has been hindered so far by a lack of coherent policies in some Member States, low degree in harmonisation of regulations and relatively high start-up costs, but also by barriers to grid access and system integration. Technological barriers, as a result of outdated and inefficient equipment, remain in many CHP systems, although significant technological advances have been made in the past decade. Besides, as a heat demand-driven system, CHP can efficiently run only during a part of the year or even of the day, which reduces their potential competitiveness. Market uncertainties about fuel prices also inhibit investment, particularly in recent years. These factors impinge on the financial status of CHP, and here the liberalisation of the market has exposed both new and old systems to very competitive conditions where short term profitability is the governing factor. Regulatory issues regarding grid access and connection are secondary compared to the previous points, but are nevertheless inhibiting the growth of CHP systems, particular medium and small sizes. However, grid connection and integration could be a greater problem with the introduction of micro-CHP on a large scale. In addition, the high costs of small and micro-CHP (including fuel cells), limited operating and design experience in households and tertiary sector applications are additional barriers for this market segment. Finally, a concern in the CHP industry is a stagnating demand for building space heating or one which is actually falling, which particularly affects the use of CHP in DHC.

7.4 Needs

Critical support is expected from the development of a favourable policy/regulatory framework to enable new investments in CHP. Focus is needed on R&D and demonstration of higher biomass technology efficiency and co-firing of biomass and coal. Important requirements for DHC are development of new pipeline structures with lower costs and less disrupting methods of laying networks, and the need for techniques to minimise heat losses and permit accurate heat consumption measurements. Targeted R&D to support commercialisation of the technology is vital for micro-CHP technologies and particularly fuel cells. Demonstration projects should be used in conjunction with financial mechanisms to stimulate mass production of micro-CHP and fuel cells, and to build up the service infrastructure that these devices will need. Furthermore, important progress is needed in electricity distribution grid integration and management. Apart from the need for advanced CHP system operation, a thorough review is also needed on the portfolio of thermal (and possibly

electricity) storage technologies and improved cooling systems. Further research and demonstration of high-temperature CHP should facilitate expansion of CHP in new industrial applications. Finally, the key to growth is the development and use of more efficient equipment and stable long-term fuel and electricity prices. Electrical efficiencies of 20 % are needed for 1 kW units and in excess of 30 % for larger systems (over 35 % for large, centralised systems).

7.5 Synergies with other sectors

Renewables and CHP both require a decentralised heat and electricity supply approach, and compliment each other in meeting demands. Besides, with the increase in variable power generation from renewables, the supply of peak loads on the power market will become even more significant than today. CHPs therefore could adapt their operations to supply this market segment. However, this will require greater use of heat storage. Moreover, DHC networks can be used to absorb excess of electricity from wind and solar power generation. With respect to distributed generation, CHP can play a major role in strengthening the electricity distribution grid by assisting grid stabilisation and reducing the need for further investment.

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8 CARBON CAPTURE AND STORAGE IN POWER GENERATION

8.1 Technological state of the art and anticipated developments

Carbon Capture and Storage (CCS) technologies can be applied to energy production wherever CO₂ is produced in large quantities. This includes, but is not limited to, power generation and promises near zero emission electricity from fossil fuels. CCS is generally understood as consisting of three major steps: carbon dioxide capture from flue/fuel gases; CO₂ transport; and CO₂ storage. For each step there are currently several technology options, with different levels of performance and maturity, so numerous constellations for CCS can be envisaged.

The portfolio of technologies currently being developed applies to both newly built power plants and also to retrofits of existing plants.

Although each step can be realised with proven technologies, these technologies need to be adapted for use in the full CCS value chain. Internationally, up to 20 pre-commercial implementation projects are aiming to demonstrate various combinations of CCS technologies, with more projects in the construction and development phase.

The major component CCS technologies are presented below.

8.1.1 Carbon Capture and Storage Technologies

CCS is divided into CO₂ capture at the industrial source, transport to a place of storage and permanent storage.

- **Capture**

Currently there are three main methods for capturing CO₂ in power plants:

Post-combustion capture involves removing the dilute CO₂ from flue gases after combustion of the fuel. Currently, the favoured technique for post-combustion capture is *chemical solvent scrubbing*. The flue gases are washed with a solvent that separates the CO₂ from nitrogen. In a de-absorber, the solvent is reheated and the CO₂ driven off. CO₂ is then cooled and compressed, ready to be piped away. The technique can be applied to both pulverised coal and natural gas sub- and super-critical power plants, and can be retrofitted to existing plants without significant modifications to existing infrastructure. Retrofitting would therefore appear to be the most economical technology. The most widely used solvent for CO₂ scrubbing is monoethanolamine (MEA). Apart from the solvent degradation by impurities such as SO_x, NO₂ and O₂, the main issue with MEA is the large amount of energy required for its regeneration. Alternative solvents which require lower energy for regeneration and at the same time present better absorption-desorption and corrosive properties are being developed, with currently amino salts and chilled ammonia the most promising. Solid sorbents at high temperature, such as calcium-lithium based oxides, and sodium and potassium oxides are also being investigated.

Pre-combustion capture involves removal of CO₂ prior to combustion of hydrogen in a gas turbine, in an integrated gasification combined cycle (IGCC) plant. Solid, liquid or gaseous fuel is first converted to a mixture of hydrogen and carbon monoxide using one of a number of proprietary gasification technologies. In a so called 'shift reactor', the carbon monoxide is oxidised to CO₂, which is subsequently separated from the hydrogen. The hydrogen is diluted with nitrogen and burned in a gas turbine. The partial pressure of the CO₂ in the gas to be treated is about 1000 times higher than for post-combustion capture and *physical solvents* for the separation are preferred. Scrubbing of CO₂ with physical solvents is a well established process in the chemical industry, e.g. ammonia production and synthesis gas treatment. Cold methanol (Rectisol process), dimethylether or polyethylene glycol

(Selexol process) and propylene carbonate (Fluor process) are the most commonly used solvents. Other possibilities for CO₂ separation include: adsorption on solid materials, such as zeolites or activated carbon; pressure-swing adsorption, where the adsorbent is regenerated by reducing the pressure; and temperature-swing adsorption, where the adsorbent is regenerated by increase of temperature. Separation can also be achieved with selective membranes. However at the present time membranes cannot achieve a high degree of separation and improvement is needed for their cost-effective use on a large-scale. Another challenge is the modification of gas burner and turbine technologies to achieve higher efficiencies in the electricity production from hydrogen combustion.

In **oxy-fuel combustion**, the air is separated in an air separation unit, often cryogenic, prior to combustion, into nitrogen and oxygen. The fuel is then burned in pure oxygen. In practice for temperature control, oxygen is diluted by recycling some of the CO₂ from the flue gas. The main advantage of oxy-fuel combustion is the high concentration of CO₂ in the resulting flue gas (>80%), so that only relatively simple purification of CO₂ is needed before storage. This process, which is currently being tested in the EU at pilot scale, promises high efficiency levels and offers major business opportunities, including the possibility of retrofitting existing plants. The main disadvantage is the large quantity of oxygen required, which is expensive both in terms of capital costs and energy consumption.

Among all capture methods, CO₂ scrubbing techniques are the most mature. MEA-based scrubbing has been utilised for more than 60 years for natural gas purification and food-grade CO₂ production. In particular, Rectisol and Selexol processes have been commercially used since the 1990s for CO₂ capture in the refining, chemical and fertilizer industries and are today extensively used in gasification plants to purify synthesis gas for downstream chemical applications. Current units, using these techniques, are able to remove thousands of tonnes of CO₂ per day [1, 2, 3]. However, they have not yet been demonstrated on the large scale necessary for 90% CO₂ capture from a typical 500MW coal-fired power plant where 10 000 – 15 000tons of CO₂ would be removed per day.

Other capture technologies such as anti-sublimation, enzymes and algae for post-combustion and chemical looping and high pressure oxy-reactor are still at an early stage of development, with commercial deployment generally considered to be unlikely before 2025.

- **Transport**

Carbon dioxide is already transported for commercial purposes by road tanker, by ship and by pipeline. Although each of these methods is practical, the future quantities of CO₂ to be transported from source to storage site are considerable and hence, it is most likely that local and regional infrastructures of pipelines will ultimately need to be developed. The technologies involved in pipeline transportation vary little from those used extensively for transporting gas or oil. Indeed, in some cases, it may be possible to re-use existing but redundant pipeline infrastructures. Large networks of CO₂ pipelines, mainly associated to Enhanced Oil Recovery (EOR) operations, have been in use since the early 1980s and are operated commercially with proven safety and reliability records. Most of them lie in the US where more than 4 000 km of pipelines already exist, with the Permian Basin containing between half and two thirds of the active CO₂ floods in the world [4, 5]. Recently networks have started to operate in Europe, with the biggest infrastructures in the North Sea, e.g. 160km pipeline for Snøhvit LNG project, and in the Netherlands, about 80km pipeline from Rotterdam to Amsterdam to transport CO₂ to greenhouses.

- **Storage**

Various technical options for the long-term storage of CO₂ are being researched. Geological storage is by far the cheapest and most promising option and industrial geological CO₂ storage projects have already been initiated in Europe and worldwide. Different types of geological formations are being

used and investigated, especially oil and gas reservoirs, deep saline aquifer formations and unmineable coal beds. There is an estimated global storage potential of 10 000 Gt CO₂, with 117Gt in Europe [6]. Compressed CO₂ is already injected into porous rock formations by the oil and gas industry, e.g. for EOR, and is proven at a commercial scale.

Due to its possible environmental implications, the current option of CO₂ storage deep in the oceans is no longer considered an option [7].

Mineral carbonation is an alternative for storing CO₂ in materials. However, due to the large amounts of energy and mined minerals needed, it is not likely to be cost effective [7].

8.1.2 Zero Emission Fossil Fuel Power Plant Projects

Presently the two major technologies for electricity production from fossil fuels in the EU are Pulverised Coal Combustion and Natural Gas Combined Cycle. These technologies, along with oxy-fuel combustion and integrated gasification combined cycle (IGCC), are given in more detail in Chapter 9. Both systems could be equipped with CCS technology, both in new plants and as retrofit applications.

Zero-emission fossil fuel power plants (or ZEP plants) will capture at least 85% of the CO₂ formed during the power generation process. The captured CO₂ will be transported to suitable underground locations where it will be stored permanently and safely. Currently, all elements of the technology of ZEP plants have been developed and utilised by other industrial sectors, but on much smaller scales than those needed for electricity generation and to-date, no integrated commercial CO₂ capture and storage (CCS) project with power generation is in operation.

Seven commercial projects with CO₂ capture, transport and storage are currently running. The Canadian Weyburn-Midale project, in the frame of an EOR plan, demonstrates CO₂ storage using CO₂ from a gasification plant producing synfuel. In Norway, CO₂ removed from natural gas up-grading, has been injected since 1996 and 2008, into the offshore Sleipner and Snøhvit fields respectively, and in Algeria in the In Salah field, since 2004. Two large projects are currently on-going in Australia (Otway basin) and in the Netherlands (K12B) and several are in preparation (among the largest, the Gorgon project and the Monash project in Australia). Altogether, about 3Mt of CO₂ are stored annually [7, 8]. In 2007, about 95 CO₂-EOR projects worldwide, mainly in the USA, injected about 40Mt of CO₂ into oil reservoirs [9].

The world's first coal fired oxyfuel CCS plant with power generation is Vattenfall's Schwarze Pumpe 30 MW pilot plant, inaugurated in September 2008 in Spremburg, Germany. The captured CO₂ however, is not yet stored. Several other projects for demonstration of CO₂ capture from power plants, based on a variety of storage techniques, are currently planned in the EU-27, and between 2010 and 2017, 48 projects could become operative [10].

Expected development

Overall, the ZEP plant technology is widely considered ready for large scale demonstration. The European Commission has committed to support up to 12 projects to be operational by 2015. Funding will come from individual governments, the EU and industry. From the technological point of view, ZEP plants could be operating commercially from 2020, with first-of-a-kind plants coming into operation by 2015. The first generation of commercialised pulverised coal, natural gas turbine combined cycle and IGCC coal plants with CO₂ capture are expected to have efficiencies of 35%, 49% and 35% respectively, with corresponding specific capital investments of the order of 2 250 €/kW, 1 200 €/kW and 2 100 €/kW [11]. Due to their comparatively higher emission levels when unabated, it

is expected that the first CCS plants will be coal-fired. It is anticipated that by 2030, technological developments will have reduced the efficiency gap between ZEP plants and equivalent non-ZEP plants to about 10 percentage points or less [11]. Similar developments will have ensured that the capital cost of ZEP plants will be decreased by 10 to 20% compared to the first generation units [11]. These developments should drive the cost of CCS down from the current level of 60 – 90 € per tonne of CO₂ abated to 35 – 50 € in the early commercial phase (2020+) and to 30 – 45 €, when total installed capacity could increase to ~ 80GW [12].

8.2 Market and industry status and potential

Currently, two main industrial sectors are involved in developing CCS technology: electricity utilities and oil and gas companies, along with the corresponding fuel, equipment and service suppliers. This suggests a potential division within the CCS value chain, whereby the utilities could operate capture steps, and oil and gas companies could be involved in transport and storage. There is also likely to be a future role for pipeline operators: new networks of CO₂ pipelines are now being considered in different parts of the world and their development and management could become a major international business opportunity.

ZEP plants would compete with conventional power plants for a share in power generation capacity if, as anticipated, they become commercially viable within a carbon pricing framework such as the EU Emission Trading Scheme. Alternatively they could be further enabled by regulation. The actual level of penetration will depend on the time of commercialisation and deployment, on the regulatory framework, the environmental constraints and the extent of the CO₂ transport network. The baseline for the CCS Technology Map assumes that ZEP plants are not commercially deployed in the EU-27 before 2030, with an estimated maximum potential of up to 80GW [12].

From an emissions mitigation point of view, it is important to consider the geographical profile of fossil fuel reserves and, hence, likely locations for fossil fuel use and deployment of CCS. Since a number of developing countries have significant fossil fuel reserves, it will be important to consider the possibility of developing the technology in industrialised countries with later diffusion to emerging economies. For stimulating such cooperation, work is presently on-going to adapt international financial instruments, such as the Clean Development Mechanism under the Kyoto framework [13]. The European Commission in the context of the EU-China Climate Change Partnership is already active in this field, financing the EU-China Near Zero Emissions Coal Plant project [14, 15], whilst collaboration with other emerging economies, such as South Africa [16], OPEC countries [17], India [18] and Brazil [19] are under discussion.

In the new energy scenarios, where renewables are going to play a greater role in electricity production, fossil-fired power plants, inherently flexible, could be used to balance changing demand and provide back-up capacity for an intermittent renewable generation. It is also important to note that a portfolio of renewable options are under development and these other technologies should not be ignored when considering the impact of carbon capture plants. For example, there are specific opportunities to use carbon capture with biomass combustion for power generation, particularly in plants, where biomass is co-fired with pulverised coal.

Iron, steel, cement aluminium manufactures, together with fertiliser sector, accounting for about 19% of total world greenhouse gas emission [20], are also interested in CCS employment. Up to now however involvement and commitment of these industries in the development and application of CCS has been limited.

Carbon dioxide can be captured and in many cases already captured in significant quantities in ammonia production, in industrial production facilities, such as coal-to-chemicals, and energy

processing, such as coal and gas-to-liquids operations, and well heads at gas fields. Companies operating in these fields could therefore also benefit from CCS deployment.

Hydrogen has been identified as one of the possible additional products that could give an added value to ZEP plants operating in a poly-generation scheme based on gasification technology, potentially producing other synthetic fuels, including natural gas.

8.3 Barriers

Financial, social and regulatory issues could all present barriers to CCS demonstration and deployment. The high cost of first-of-a-kind plants is the main barrier to further progressing with the technology. Securing public confidence and public awareness of the CO₂ emission reduction potential of CCS are key social and political challenges. The EU CCS Directive adopted in April 2009 put a legal framework for geological storage of CO₂. This directive however must now be implemented at a national level. Key issues related to storage are presently the permit/licensing procedures and long term liability. Uncertainties in carbon prices and in the emissions trading scheme are also of concern for a fast commercial deployment.

8.4 Needs

A prerequisite for the large-scale deployment of CCS is the demonstration of the technical and economical feasibility of existing technologies in a fully integrated chain. For this purpose, the EU is committed to support up to 12 integrated CCS projects to be operational by 2015. Funding has been made available via the European Energy Programme for recovery, and should also become available from the new Entrants reserve of the ETS during 2010. Financial incentives for demonstration activities and, in the longer term, for enabling commercial CCS deployment worldwide within a carbon pricing mechanism will be vital to encourage enterprises' enthusiasm for CCS and their capacity to implement it. To ensure that learning from the first demonstration projects is maximised, the European Commission is establishing a CCS Project network to coordinate knowledge sharing, awareness and dissemination.

Meanwhile more efficient and cost competitive CCS technologies have to be developed through ongoing research. Improvement of power plant efficiency, development of new materials (for advanced ultra-supercritical boilers and steam and gas turbines), development of innovative and more cost-effective capture processes, and assessing the safety of CO₂ storage are the priority topics. Reducing the costs of CO₂ capture through better technologies is considered feasible and essential, and alternatives such as ionic liquid solvents, enzymatic separation and physical separation are emerging. The biggest concern in long term geological storage is the security of it. The environmental impact and safety of CO₂ storage requires better understanding. Monitoring and modelling techniques, for checking CO₂ migration, diffusion, fluid-rock interactions, and cap rock integrity need to be developed for verifying storage security. In parallel, a better assessment of storage potential and site characterisation, especially of saline aquifers, is needed. CO₂ transport has been demonstrated on the commercial scale, however CO₂ pipelines operate at a much higher pressure than, for example, natural gas pipelines, and CO₂ technology has not developed to the same extent as oil and gas pipelines. Issues related, for instance, to CO₂ composition, pipe rupture and longitudinal cracking are still of concern and need to be addressed.

Public perception will have a significant role to play in CCS deployment. The public awareness and knowledge of CCS is currently low and is a priority area to be dealt with by all actors involved. Education on climate change and communication of the main technical economic and social aspects of CCS could be the key to the ultimate success of CCS in reducing CO₂ emissions.

8.5 Synergies with other sectors

Due to the scale of CCS technology, the companies involved in their development and application tend to be large international firms. Oil and gas (O&G) companies, from both the upstream sector as well as downstream sector, could profit from CCS deployment. The up- and mid-stream O&G sector could provide sinks for CO₂ storage, enhancing at the same time the potential for EOR operations. CO₂ is nowadays captured on the commercial scale for natural gas cleaning: collaboration between the downstream O&G sector and power sector would be therefore important to maximise efforts and exploit expertises.

Several industrial processes produce highly concentrated streams of CO₂ as a by-product. Industrial processes that lend themselves to carbon capture are ammonia manufacturing, fermentation and hydrogen production from fossil fuel reforming. Cooperation between these industries and the power sector is essential for knowledge sharing and thus accelerating CCS deployment.

Additionally, enhanced interactions with the materials research community can facilitate the development of new materials needed for efficiency improvements and cost reductions.

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9 ADVANCED FOSSIL FUEL POWER GENERATION

9.1 Technological state of the art and anticipated developments

Fossil fuel power generation is the biggest contributor to CO₂ emissions and any gains in conversion efficiency would translate to substantial CO₂ savings. For instance, each % point efficiency increase is equivalent to about 2.5 % reduction in tonnes of CO₂ emitted. Power plant efficiency is therefore a major factor that could be used to reduce global CO₂ emissions. The main fossil fuel based electricity generation technology in the world and in the EU is pulverized coal (PC) combustion. The majority of pulverised coal plants are more than 15 years old and operate with sub-critical steam parameters and efficiencies between 32 - 40 % (lower heat value basis). Upgrading low-efficiency fossil plants should be a high priority in the future. Supercritical (SC) plants with steam conditions typically of 540 °C and 250 bar have been in commercial operation for a number of years and have efficiencies in the range 40 – 45 %. However, if the best available technologies were to be used, as, for example, “advanced supercritical” plants with steam conditions up to 600 °C and 300 bar [1, 2], it should be possible to reach net efficiencies between 46 – 49 %. Reaching these steam conditions demands successive reheating cycles and stronger and more corrosion resistant steels that are inevitably more expensive than standard boiler steels. Nevertheless, the achieved overall efficiency improvement easily counterbalances additional cost and on-site energy consumption. There is a limit to the benefit of increasing steam pressure at a given temperature in that a reduced volume of steam leads to higher rates of leakage as the steam passes through the turbine. Amongst numerous other factors, site specific requirements such as geographical location, i.e. inland or coastal, availability of cooling water, as well as ambient temperature are also key factors determining the actual efficiency achieved.

The next step for the utilisation of coal, and under development since the 1990s, is ultra-supercritical (USC) power plants. Steam conditions of 600 °C and 300 bar can be achieved today, resulting in efficiencies of 45 % and higher for bituminous coal fired power plants [3]. Several years of experience with good availability have already been achieved [4], for example with Unit 3 of the Nordjyllandsvæket USC combined heat and power plant near Aalborg in Denmark, where 47 % electrical efficiency is achieved with an output of 410 MW and steam conditions of 582 °C and 290 bar. The plant started operation in 1998 and benefits from the availability of seawater to provide cooling. High electrical generation efficiency of 43 % has also been achieved with the more difficult to handle lignite (brown coal) at the 1 012 MW_e Niederaussem K plant in Germany [5]. Future USC plants are planned to use 700 °C and 350 bar or higher, which should give net efficiencies of the order of 50 – 55 %. In 1998, a group of major suppliers to the power industry and some of the major utilities in Europe started a 17-year demonstration project, financially supported by the European Commission's THERMIE programme, called the "Advanced (700 C) PF Power Plant". The higher USC steam conditions necessitate use of stainless steels and nickel-base alloys in the highest temperature regions of the boiler to resist corrosion degradation and mechanical deformation. With the elevated steam conditions, advantage will have to be taken of advanced turbine blading technology and state-of-the-art condenser configurations to achieve very low turbine exhaust pressures, thereby maximising the pressure drop across the turbine to provide maximum power generation. In addition, it has the potential to provide large quantities of low pressure process steam extracted from the turbine for district heating, industrial use or an on-site CO₂ capture plant. The main aim of the THERMIE 700 °C steam coal power plant project is to make the jump from use of steels to nickel-based super alloys for the highest temperatures in the steam cycle which should enable efficiencies in the range of 50 – 55 % to be achieved. When a 700 °C steam coal power plant will become a reality is not known.

Choice of fuel can have a marked impact on power plant efficiency. High power generating efficiencies can also be reached with natural gas which has been used increasingly over the last 20 years, initially to address concerns over acid emissions (SO_x and NO_x) and to provide better demand

management. It also has been a lower cost option, at least in terms of plant investment, although combined cycle mode with gas and steam turbine are needed to achieve high efficiencies. Combined-cycle plants can achieve thermal efficiencies of 50 to 60 %. Recent high natural gas prices and large fluctuations in price have increased the financial risk of operation.

Fuel flexibility is becoming increasingly important as fuel resources are depleted and costs can fluctuate significantly over the life of a power plant. Substantial efforts have been made to use alternative fuels in pulverised coal power plants. In recent years this has been driven mainly by the need to increase power generation from renewables and so biomass has been widely used in amounts typically up to 5 % energy input. Markets for trade in biomass for co-firing are not yet mature and as a consequence feedstock costs can vary widely in a relatively short space of time. The impact of biomass co-firing on power generation efficiency is very small within the low range of inputs of biomass currently used. There is an additional cost for preparation of the biomass (milling) for injection into pulverised coal plants (direct co-firing). In-direct co-firing via a pre-gasification step followed by injection of a product gas (rich in CO and H₂) into the coal boiler is not yet commercial, although large-scale demonstrations, e.g. the Amercentraale in NL, have been made.

For combustion, fuel flexibility seems to be best achieved using fluidised bed systems which have been extensively exploited for biomass in the Nordic countries. A large-scale coal-fired circulating fluidised bed (CFB) is being commissioned in 2009 in Poland. The Lagisza CFB plant has a capacity of 460 MWe and will operate with supercritical steam giving in excess of 43 % efficiency, with very low NO_x emissions and easy in-bed capture of sulphur. The reported cost of investment of EUR 150 million equates to 326 €/kW installed capacity, though this figure covers only the boiler island. Integrated gasification combined cycle (IGCC) has been successfully demonstrated at two large-scale power plant demonstration facilities in Europe (Buggenum-NL and Puertollano-SP), achieving plant availability up to 80 %. The technology is ready for commercial exploitation. IGCC has a smaller cost differential between CO₂ capture and non-CO₂ capture than PC combustion. The cost of IGCC without capture is still higher than PC [3]. With complete gasification of coal, the ratio of power output between gas turbine and steam turbine will be around 55 - 45 % and the overall efficiency around 42 % [6]. High temperature entrained flow gasification avoids tar related problems and increases gasification rate, allowing better matching with modern high capacity gas turbines that achieve high efficiencies. High pressure (in the range 30 – 70 bar) also reduces syngas clean-up costs and should save on compression costs for eventual carbon dioxide capture. However, on the other hand, this complicates coal feeding that could have a negative impact on fuel flexibility. IGCC with CO₂ capture capability has yet to be demonstrated and unlikely to be ready for commercialisation until 2020. Further into the future, IGCC with hybrid fuel cell, gas turbine and steam turbine could conceivably reach 60 % efficiency with zero emissions.

For both retrofitting of existing PC plants and new PC combustion plants, oxyfuel combustion is a promising option that will minimise the cost of the CO₂ capture step, since the flue gas contains around 90 % CO₂. There are many unquantified operational effects associated with oxyfuel combustion that will need to be addressed before it could be used commercially. A 30 MW demonstration scale project was started in 2008 in Germany.

Beyond fuel flexibility, there is increasing interest in polygeneration from coal, so that not only electricity and heat are the products, but also chemical feedstocks and alternative fuels for transport will be important. The IEA Clean Coal Centre has recently published a report on the potential for polygeneration [7].

The costs of new power plants have increased rapidly in the last 3 or 4 years, mainly as a consequence of worldwide demand for raw materials (steel and other building materials) and the shortage of manufacturing capacity due to rapid industrial expansion. The impacts of the recession that started at

the end of 2008 cannot yet be judged so the data given below should be treated with care. All costs should be considered to include engineering, procurement and construction (EPC) unless otherwise stated. The costs of a “best practice” supercritical power plant was (including flue gas desulphurisation and selective catalytical reduction of NO_x) around 800 €/kWe in 2004 [8]. In 2007 the investment cost of the SC technology with pulverised coal was of the order of 1 300 €/kW. The cost of gas turbines combined cycle using natural gas as fuel had a specific capital investment of the order of 600 €/kW. The cost for IGCC has been given as 1 000 – 1 200 €/kWe in 2004 [9] and 1 800 €/kWe in 2007 [10].

9.2 Market and industry status and potential

Fossil fuel power plants dominate the European electricity generation fleet, providing 56 % of the total electricity demand, followed by nuclear energy (31 %) and renewables (13 %). In the EU, coal plants have a share of 29 % of electricity generation and natural gas combined cycle plants 19 %. All energy forecasts show that fossil fuels will remain the main fuel for electricity generation in the medium and long term, owing to the existence of extensive coal reserves and their good distribution across politically stable regions, retaining a share in power generation of the order of at least 40 – 50 % in 2030 [11]. The use of coal will likely increase in the future under any foreseeable scenario because it is cheap and abundant and CO₂ capture and storage (CCS) is the critical enabling technology that would reduce CO₂ emissions significantly while also allowing coal to meet the world’s pressing energy needs [12]. A scenario where the price of CO₂ is high should lead to a substantial reduction in coal use in 2050 relative to “business as usual”, but still with increased coal use relative to 2000. In such a carbon-constrained world, CCS is the critical future technology option for reducing CO₂ emissions [12]. Consequently, application of advanced supercritical and ultra-supercritical fossil power technologies to function alone or in combination with CCS is essential to minimise CO₂ emissions.

With continually growing electricity demand and limitations on the potential for exploitation of alternative, renewable sources of energy, fossil power, using coal in particular as a widely available resource that affords security of supply, will inevitably dominate well into the 21st century [12]. Improved efficiency of conversion of the fuel to electricity, particularly of low-efficiency sub-critical power plants, with maximum utilisation of residual heat is now driving industry to cut emissions. Sub-critical power plants (35% efficiency) emit 943 kgCO₂/MWh of electricity, while the best available supercritical power plants with an efficiency of 46% emit 720 kgCO₂/MWh of electricity [13], so major retrofitting of old sub-critical power plants with supercritical steam cycles or retiring old plants and replacement with new ones could save 23.6% CO₂ emissions for the same power produced. The main factors affecting efficiency have been described in detail by Beers [3]. Various additional measures can be taken to improve efficiency, for example, intensive coal up-grading (mainly drying) could reduce CO₂ emissions by 0.3 to 0.5 Gt each year globally (from 8 Gt annual CO₂ emissions from coal use), retrofitting of existing plants by adding reheating stages, increasing the number of feed heaters, increasing the final feed water temperature and generally improving housekeeping by reducing leakages and heat losses, collectively providing 4-5 percentage points efficiency increase [13]. Co-firing with biomass also reduces fossil CO₂ emissions, the higher the base-plant efficiency, the higher the CO₂ saving, although technical challenges associated with fuel feeding, fouling and corrosion limit the amount of biomass that can be added without compromising operating reliability [14]. Improved efficiency and biomass co-firing will save costs imposed by the future Emissions Trading Scheme (ETS) from 2013 and save costs in the open energy market developing in the EU. The next step, involving carbon capture and storage (CCS) at a demonstration scale beyond 2015, will demand the highest power generation efficiency in order to compensate for the inevitable energy cost associated with CO₂ capture processes.

9.3 Barriers

The power generation sector in the EU is a mature sector and has been thriving in a relatively undisturbed commercial environment until quite recently. Privatisation in many countries over the last 10 - 15 years resulted in reduced investment in new plant, although work on improving the supercritical steam technology advanced without significant interruption. The industry also saw the need for and acted accordingly to ensure development of technology to support ultra-supercritical steam conditions and associated higher generation efficiency. The main driving forces for the technology development have been, and continue to be, reduced emissions and both investment and operating costs. Costs and emissions are intimately linked.

The cost of CO₂ emissions within the European Emissions Trading Scheme (ETS) is likely to have a substantial impact on the cost of electricity production. This cost impact can be reduced by maximising the efficiency of power production. Hence, supercritical and eventually ultra-supercritical steam conditions of the highest grade need to be used. Without major refitting, however, the possibility to improve efficiency in each power plant is limited by installed boiler design and the turbine. Refitting and upgrading power plants are nevertheless possible and there are possibilities to make small efficiency improvements. Fossil CO₂ emissions can be reduced by co-firing with biomass. The barriers to direct co-firing biomass are very low as only fuel feed systems need to be changed significantly. Co-firing of waste, of which there are millions of tonnes potentially available, pose both a legal barrier and a technical challenge. Under the European Waste Framework Directive (WFD) [15], waste combustion may only take place in a plant that conforms to the European Waste Incineration Directive (WID) [16]. While a number of fossil power plants have experimented with waste as a fuel, most of them had to abandon the work at the end of 2005 as the WID came into full force. There were also some problems of increased boiler corrosion. However, the amount of Solid Recovered Fuel (SRF) produced from municipal solid waste amounts to millions of tonnes each year and at least some of the SRF could be used in power plants without adverse effects. The main problem is classification of the SRF as a “product” rather than waste.

The main technology challenge by far on the immediate horizon is the introduction of CCS. While this subject is dealt with in Chapter 8, CCS is already having a significant effect on the power generation sector in terms of investment uncertainty in the waiting period during demonstration of CCS plants. Full introduction of ultra-supercritical plants seems to be a matter of cost associated with the expected high risk of using a new technology. Reliability will need to be proved for ultra-supercritical steam cycle plants. Whether or not polygeneration becomes a commercial reality in the power generation sector in Europe is as yet unknown.

9.4 Needs

A stable economic climate is the main factor ensuring that barriers to investment and operation of power plants are kept as low as possible. This means greater stability of investment cost than has been experienced in the last 3 - 5 years and a stable CO₂ price when the ETS is in full operation. Higher cost of investment in high temperature steam cycles, combined with the cost of CO₂ emissions, have to be weighed against increased income from electricity and heat from each unit of fuel.

Therefore, there needs to be development of a regulatory market framework and of appropriate policies that will promote financial stability of the energy market, which will in turn provide stability to the power generation sector. The financing and regulation of the infrastructure for CO₂ transport and storage will need to be addressed on both the European level and the Member State level to enable the power generation sector to plan its capacity and fuel supplies for the future.

9.5 Synergies with other sectors

The existing power generation industry has traditionally operated independently of other industrial sectors as both pulverised coal combustion and natural gas combined cycle technologies are not used by other sectors. However, with the advent of CCS and the possibly of growth of polygeneration, there will be closer technology synergies in particular with the oil industry (IGCC, CO₂ transport and storage, hydrogen and synthetic fuels) and the chemical process industry (CO₂ and polygeneration products).

Enhanced interactions with the materials research community could facilitate the development of new materials and maintenance/repair techniques needed to maintain plant reliability, for efficiency improvements and cost reductions.

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10 NUCLEAR FISSION POWER GENERATION

10.1 Technological state of the art and anticipated developments

Nuclear fission energy is today a competitive and mature low-carbon technology, operating at very high levels of safety. The installed nuclear electricity capacity in the EU is 132 GWe, which provides one third of the EU's generated electricity [1, 2]. Most of the current designs are Light Water Reactors (LWR) of the second generation, capable of providing base-load electricity often with availability factors of over 90%. There have been only a few new nuclear power plants connected to the grid in the last two decades, and as a result of decommissioning of old plants the total number of reactors in Europe has decreased. Nevertheless electricity supply from nuclear has remained constant and the levelised cost has decreased owing to improved efficiency, power upgrade and improved availability factor. More recently there has been a renewed interest in nuclear energy, referred to as "nuclear renaissance", mainly driven by concerns over climate change, security and independence of supply and energy costs.

It has been demonstrated that Generation-II plants can be safely and economically operated for up to 60 years through the development of improved harmonised plant-life management technologies and plant licence extension practices (PLIM/PLEX) and that developments in fuel technologies can still lead to improvements in reactor performance [3]. The first Generation-III reactors, which are an evolution of thermal reactors with even further improved safety characteristics and economy, are now being built. In the coming decades, nuclear electricity generation should increase or at least maintain its current level by a combination of lifetime extension and power upgrades of Generation-II reactors and new build of Generation-III reactors. Two 1.6 GWe Generation-III reactors are presently under construction in Finland and France, targeted for connection to the grid in 2012. The Finnish reactor was a first-of-a-kind (FOAK) and the construction has suffered delays with the Overnight Cost increasing from 2 000 to 3 100 €/kW_e, whereas the Overnight Cost for the second reactor in France is now 2 400 €/kW_e. In series production, the industry expects the cost to be 2 000±500 €/GW_e, which is in line with recent international studies [4, 5, 6, 7]. An additional capacity of 100GW_e of Generation-III reactors over the next 25 years is a reasonable estimate, which would require an investment in the range of 200-280 billion Euros. The capital costs represent typically 60-70% of the levelised cost for nuclear electricity, operation and maintenance 20-25% and fuel 10-15%. The front-loaded cost profile means that the levelised cost is very sensitive to construction time and the financial schemes for the investment [4, 5, 6, 7]. Estimates in 2007 for UK resulted in range of 31-44 £/MWh (37- 53 €/MWh) [7].

Though uranium is relatively abundant in the Earth's crust and oceans, estimates of natural reserves are always related to the cost of mineral extraction. As the price of uranium increases on world markets, the number of economically exploitable deposits also increases. The most recent estimates [8] identified 5.5 million tons of uranium (MtU) that could be exploited below 130\$/kg. The total amount of undiscovered resources (reasonably assured and speculative) available at an extraction cost below 130 \$/kgU is estimated at 10.5MtU. Unconventional resources, from which uranium is extracted as a by-product only, e.g. in phosphate production, lie between 7 and 22 MtU, and reserves in sea water are estimated to be 4 000 MtU. Japanese studies suggest that uranium from sea water can be extracted at 300€/kg [8]. At a conservative estimate, 25 000 tons of the uranium are required to produce the fuel to generate 1 000 TWh_e in an open fuel cycle. The global electricity supplied by nuclear is 2 600 TWh_e, which means that the conventional resources below 130\$/kgU at the current rate of consumption would last for at least 85 years with the already identified resources (5.5 MtU) and 246 years, if the undiscovered are also included (5.5+10.5MtU). In addition to uranium, it is also possible to use thorium, which is three times more abundant in the Earth's crust, though would require different

reactors and fuel cycles. Nonetheless, natural resources are plentiful and do not pose an immediate limiting factor for the development of nuclear energy.

However, in a scenario with a large expansion of nuclear energy, resources will become an issue much earlier, especially since new plants have at least a 60-year lifetime and utilities will need assurances when ordering new build that uranium supply can be maintained for the full period of operation. Eventually, known conventional reserves will all be earmarked for current plants or those under construction, and this could happen by the middle of this century. This underlines the need to develop the technology for a new generation, the so-called Generation-IV, of reactors and fuel cycles that are more sustainable. In particular, fast neutron breeder reactors could produce up to 100 times more energy from the same quantity of uranium than current designs and may also significantly reduce the amount of ultimate radioactive waste for disposal [3, 9, 10]. Fast reactors convert non-fissile material (U-238) in the fuel into fissile material (Pu-239) during reactor operation so that the net amount of fissile material increases (breeding). After re-processing of the spent fuel the extracted fissile materials are then re-cycled as new fuels. Reduction of the radiotoxicity and heat load of the waste is achieved by separating some long-lived radionuclides, the minor actinides, which could then be “burned” in fast reactors or alternatively in Accelerator Driven Systems (ADS), through transmutation. The fast reactor concept has been demonstrated in research programmes and national prototypes in the past, but further R&D is needed to make it commercially viable and to develop the designs in compliance with true Generation-IV criteria. Major issues involve new materials that can withstand higher temperatures, higher burn-ups and neutron doses, corrosive coolants; reactor designs that eliminate severe accidents; and development of fuel cycles for waste minimisation and elimination of proliferation risks. Fast reactors are expected to be commercially available from 2040.

So far nuclear power has primarily been used to produce electricity, but it can also be used for process heat applications [3, 4]. Currently, LWRs are already being used to a limited extent for some lower temperature applications (200°C), such as district heating and desalination of seawater. Existing designs of High-Temperature Reactors (HTR) that can reach 800°C can be deployed in the coming decades and Very-High Temperature Reactors (VHTR) that can reach gas coolant temperatures beyond 1 000°C are being studied as a Generation-IV concept for later deployment. Process heat applications include petroleum refinery applications (400°C), recovery of oil from tar sands (600-700°C), synthetic fuel from CO₂ and hydrogen (600-1000°C), hydrogen production (600-1000°C) and coal gasification (900-1200°C). Small reactors, that can be inherently safe and used to support specific high energy applications and often in remote areas, are another very interesting application that is receiving more attention, in particular in the IAEA INPRO Initiative.

The management of radioactive waste, either as spent fuel or ultimate waste, depending on the national strategy, is a key issue for public acceptance of nuclear energy. There is scientific consensus that geological disposal is the only safe long-term solution for the management of ultimate waste. After a long period of intensive research and development coupled with in-depth political and social engagement, the world's first deep geological repositories for nuclear waste will be in operation in Sweden and Finland by 2020, with France following a few years later, demonstrating that practical solutions exist for the safe long-term management of hazardous waste from the operation of nuclear power plants. Though there will also be ultimate waste from Generation-IV fast reactor fuel cycles after reprocessing, the volumes and heat loads will be greatly reduced thereby facilitating disposal operations and optimising use of space in available geological repositories.

10.2 Market and industry status and potential

Europe plays a leading role in the development of nuclear energy and has 35% of the globally installed capacity. The reactors in Europe have been in operation for 27 years on average. Current plans in most EU member countries are to extend their lifetime on a case by case basis beyond 40 years, and even

beyond 60 years in some cases, in combination with power upgrades. The first two Generation-III reactors, EPR (European Pressurised-water Reactor) are currently being constructed.

The global growth of the nuclear energy can be measured by the increasing number of reactors [1, 2] (3 more in 2005 and 2006; 7 in 2007 and 10 in 2008), but with a strong concentration in Asia. Nevertheless a number of these reactors are of European design. There are presently four reactors under construction in Europe: the EPRs in Finland and France and two smaller reactors of Generation-II type (VVER 440) in Slovakia and with plans to build new reactors in France, Romania, Bulgaria and Lithuania. Perhaps more importantly the UK has taken concrete steps towards new build with bidding beginning in 2009 from leading utilities, and Italy has declared that it intends to start a nuclear programme with a target to produce 25% of the electricity by 2030. The estimated maximum potential installed capacities of nuclear fission power for the EU-27, (150 GW_e by 2020 and 200 GW_e by 2030) appear more realistic than the baseline (115 GW_e in 2020 and 100 GW_e in 2030).

Programmes to build fast reactor and high-temperature reactor demonstrators are being implemented in Russia and several Asian countries. Although these are not Generation-IV designs, transfer of knowledge and experience from operation will contribute significantly to future Generation-IV development. In Europe, a concerted effort is proposed in the form of a European Industrial Initiative in sustainable nuclear fission as part of the Community's SET-Plan. The EII has singled out the sodium fast reactor (SFR) as its primary system with the basic design selected by 2012 and construction of a prototype of 250-600 MW_e that is connected to the grid and operational by 2020. In parallel, a gas- or lead-cooled fast reactor (GFR/LFR) will also be investigated. The selection of the alternative fast reactor technology is scheduled for 2012 on the basis of a current programme of pre-conceptual design research. The reactor will be a 50-100 MW_{th} demonstrator reactor that should also be in operation by 2020. The SFR prototype and LFR/GFR demonstrator will be complemented by a fuel fabrication workshop that should serve both systems, and by a range of new or refurbished supporting experimental facilities for qualification of safety systems, components, materials and codes. A commercial deployment for a SFR reactor is expected from 2040 and for the alternative design a decade later.

High temperature reactors dedicated to cogeneration of process heat for the production of synthetic fuels or industrial energy products could be available to meet market needs by 2025, which would trigger requirements to construct "first of a kind" demonstrators in the next few years. Indeed, such programmes are currently being set up in some countries (USA, Japan, South Africa and China). The key aspect is the demonstration of the coupling with the conventional industrial plant. Supercritical water reactors and molten salt reactors, as well as accelerator driven sub-critical systems dedicated to transmutation of nuclear waste, are currently being assessed in terms of feasibility and performance, though possible industrial applications have yet to be clearly identified.

10.3 Barriers

The high capital cost of nuclear energy in combination with uncertain long-term conditions constitutes a financial risk for utilities and investors. The lack of widespread support in the EU Member States may undermine the strength of EU industry for the development of new technologies. Harmonised regulations, codes and standards at the EU-level would strengthen the competitiveness of Europe's nuclear sector and promote deployment of Generation-III technology in the near term.

The industry, infrastructures and services that support nuclear power has shrunk significantly during the last decades. This situation in Europe is not unique but it may pose a bottleneck for the deployment of reactors in the relatively near future. One example is large forgings needed for pressure vessel heads. World capacity is limited and even at the present new build construction rate there is a waiting list for delivery of these components.

Public acceptance remains an important issue, but even though opinion is not very favourable in a number of Member States, there are signs that the mood is changing. Nevertheless, concerted efforts are still required, based on objective and open dialogue amongst all stakeholders.

International cooperation currently exists at the level of research, and this is being facilitated in the area of Generation-IV systems by the Generation-IV International Forum (GIF). However, EU industry is facing stiff competition, especially in Asia where strong corporate support for R&D is putting industry in a better position to gain leadership in the near future.

Another significant potential barrier for nuclear fission is the shortage of qualified engineers and scientists as a result of the lack of interest in nuclear careers during the 1990s and the reduced availability of specialist courses at universities. Preservation of nuclear knowledge remains a major issue, especially since most of the current generation of nuclear experts are nearing retirement.

10.4 Needs

The high initial capital investments and sensitive nature of the technology involved means that renewed deployment of currently available nuclear technology can only take place in a stable (or, at least, predictable) regulatory, economic and political environment. In June 2009, the EU established a common binding framework on nuclear safety with the adoption of the Council Directive establishing a Community framework for the safety of nuclear installations [11, 12]. This is the first binding EU legislation in this field.

In order to retain its leading position and to overcome bottlenecks in the supply chain, Europe also needs to re-invigorate the industrial supply chains supporting the nuclear sector.

Apart from this overriding requirement for a clear European strategy on nuclear energy, a new research and innovation system is needed that can assure additional funding, especially for the development of Generation-IV technology. In this context the Sustainable Nuclear Energy Technology Platform [3] plays a key role. The timescales involved, and the fact that key political and strategic decisions are yet to be taken regarding this technology, mean that a significant part of this additional funding must be public. The launch of the European Sustainable Nuclear Industrial Initiative under the Community's SET-Plan, bringing together key industrial and R&D organisations, would be a very significant step towards the construction and operation of the necessary demonstrators and prototypes. High-temperature reactors based on existing technology can also be deployed in the near future with the aim of demonstrating the co-generation of process heat and the coupling with industrial processes. This would need to be built and funded through a European or International consortium, which should also include the process heat end-user industries. In the meantime, an enhanced research effort is needed to ensure Europe's leadership in sustainable nuclear energy technologies that include continuous innovation in LWRs, qualification and development of materials, closed fuel cycle with U-Pu multi-recycling, and (very) high temperature reactors and related fuel technology. Breakthroughs are especially sought in the fields of materials to enhance safety, nuclear fuels and fuel cycle processes. Additionally, there is a need for harmonisation of European standards and a strategic planning of national and European research infrastructures for use by the European research community. The implementation of geological disposal of high-level waste is also being pursued as part of national waste management programmes, though some countries are not as advanced as others. The new Implementing Geological Disposal Technology Platform, launched in November 2009, is coordinating the remaining necessary applied research in Europe leading up to the start of operation of the first geological repositories for high-level and long-lived waste around 2020, and will facilitate progress in and technology transfer with other national programmes.

More effort is needed to inform and interact with the public and other stakeholders, and the education and training of a new generation of nuclear scientists and engineers and transfer of knowledge from the generation that designed and built reactors in the seventies and eighties needs urgent attention. The European Nuclear Energy Forum (ENEF) provides a unique platform for a broad open discussion on the role nuclear power plays today and could play in the low carbon economy of the future. ENEF analyses and discusses the opportunities (competitiveness, financing, grid, etc) and risks (safety, waste) and need for education and training associated with the use of nuclear power and proposes effective ways to foster communication with and participation of the public.

10.5 Synergies with other sectors

Nuclear energy provides a very stable base-load electricity supply and can therefore work in synergy with renewable energies that are more intermittent. Nuclear energy should also contribute significantly to a low-carbon transport sector as high temperature applications can provide synthetic fuel and hydrogen, while generated electricity could provide a large share of the energy for electrical cars. Interactions are anticipated with activities in “Hydrogen Energy and Fuel Cells” through the potential of nuclear hydrogen production and with “grids” from the characteristics of nuclear electricity generation. With respect to basic materials research, there should be synergies with other applications, such as “Biofuels” and “Clean Coal”, where materials are subjected to extreme environments. In addition, the opportunities for important common research with the fusion programme, especially in the area of materials, need to be fully exploited. The European Energy Research Alliance under the SET-Plan is also expected to provide opportunities for synergies and collaborative work in the area of nuclear materials. In general, cross-cutting research would benefit from more clearly defined channels of interaction, responsibilities and increased flexibility regarding funding and programming.

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11 NUCLEAR FUSION POWER GENERATION

11.1 Technological state of the art and anticipated developments

Within the future energy mix, nuclear fusion has some key features that make it an extremely attractive option [1, 2]. In the long term, it is one of the very few candidates for the large-scale carbon-free production of base-load power. Fusion energy, the energy source of the sun and the stars, has made remarkable progress over the last few decades and is now considered as a credible energy option for clean, large-scale power generation. It has many attractions, including an essentially unlimited supply of fuel, passive intrinsic safety, using cheap fuel with no production of CO₂ or atmospheric pollutants. Furthermore, in comparison to nuclear fission, it produces relatively short-lived, radioactive products, with half-lives limited to about 10 years. Fusion energy has already been demonstrated in Europe to work successfully, with the Joint European Torus (JET) having been in use now for over 25 years and recently performing new experiments closer to ITER conditions [3].

However, significant challenges remain to make magnetically confined fusion work reliably on the scale of a power plant, including sustaining a large volume of hot plasma for long periods at pressures that allow a large net energy gain. The plant will need materials designed into complex components capable of resisting the extreme conditions, particularly in terms of heat loads and high neutron flux, required for continuous high power outputs.

To combat these challenges, the European Fusion Development Agreement (EFDA) was created in 1999, to provide a framework between European fusion research institutions and the European Commission to strengthen their coordination and collaboration and to participate in collective activities [4]. Between 1999 and 2007, EFDA was responsible for the exploitation of JET, the coordination and support of fusion-related research & development activities carried out by the Associations and European Industry, and the coordination of the European contribution to large scale international collaborations, such as the ITER-project. In 2007, following the signature of the ITER Agreement in 2006, a significant change to the structure of the European Fusion Programme was introduced. The ITER parties had agreed to provide contributions to ITER through legal entities referred to as "Domestic Agencies". Europe fulfills its obligation through its Domestic Agency, the European Joint Undertaking for ITER and the development of Fusion Energy, called "Fusion for Energy", in short F4E, launched in March 2007 [5]. More recently, in 2008, the IAEA and ITER signed a Fusion Cooperation Agreement to cooperate on training, publications, organisation of scientific conferences, plasma physics and modelling and fusion safety and security [6].

The agreement to construct ITER, which will demonstrate the technical and scientific feasibility of mastering fusion in "burning" plasmas on the scale of a power plant, was a major step forward for fusion. Another important step is the Broader Approach agreement between the EU and Japan [7], which focuses on additional projects complementary to ITER and includes final design work and prototyping for the International Fusion Materials Irradiation Facility (IFMIF) [8]. IFMIF will subject small samples of materials to the neutron fluxes and fluences that will be experienced in fusion power plants. The goal beyond ITER and IFMIF is to demonstrate the production of electricity in a demonstrator fusion power plant (DEMO) [9], with the first demonstration of electricity production in ~30 years, after which it is hoped that fusion will be available for deployment on a large scale. The construction costs for ITER were estimated to be at least 5 B€ over 10 years, with the European Commission funding approximately 50% of the costs and with each participating country contributing at least 10% each. The costs and the final schedule for construction of ITER are today subject to a careful assessment with decisions expected at the end of 2009.

With respect to DEMO, construction costs have been estimated to be of the order of 7 B€ for a 500MWe plant (€14,000/kW_e). More recent developments have considered a proposal to produce

electricity in a demonstrator 5 years sooner than DEMO, by a relatively modestly performing “Early DEMO” or “EDEM0” [10]. The options discussed include the possibility that EDEM0 would not be required to produce electricity at a stipulated cost, and would use already known low-activation materials such as Eurofer that are expected to survive under fusion power plant conditions. With this approach, the temporal link between DEMO, ITER and IFMIF would be optimised and interest from industry could be gained earlier if fusion feasibility is demonstrated. An EDEM0 fusion power plant could begin operations in the 2030s. Nevertheless, fusion will not be a player in the nuclear energy market until ~2050, when the current European fusion development plan foresees fusion starting to be rolled out commercially. Furthermore, as fusion reactors will have the use of an “unlimited fuel supply”, there would not appear to be any “resource/feedstock availability” issues that would prevent fusion being deployed as rapidly as fission was deployed after the mid-20th century, providing the desire and the funding is available.

In the last quarter of this century, we could be entering the “Age of Fusion”, producing, alongside renewable sources, energy with an inexhaustible, environmentally benign and universally available resource.

11.2 Market and industry status and potential

It is difficult to put an obvious market position on a technology that will need another 40 years to reach maturity, especially in view of the current uncertainties in predicting the contributions from other, low carbon energy sources, particularly renewables, over such a time-scale. However, studies show that fusion power is likely to be competitive with other environmentally-friendly sources in the future electricity mix. Full size prototype power plants could feasibly run at €4 000 to €8 000/kW_e (5-9 €cts/kWh). Also with the recent start of construction of ITER and the increased contributions towards underpinning European programmes, industrial involvement is expected to accelerate should a decision be taken to speed up fusion development and deployment on the basis of new options, such as the EDEM0 fusion reactor. In any case, it remains essential that industry contributes strongly to the DEMO design team from an early stage in addition to its key role in ITER construction and operation. Industry rarely commits itself to projects with a 30-40 year time horizon, however a decision to launch EDEM0, or other options to shorten the plans for delivery of commercial reactors such as a Component Testing facility, may indeed provide the impetus to trigger earlier industrial involvement in spite of the traditional caution.

11.3 Barriers

There are currently no major political barriers to nuclear fusion development. However political obstacles may resurface in the future due to “nuclear” issues or to the high level of public investments needed in the short term for a long term return. The public perception, in particular concerning safety and waste, might come into play once a commercially viable power plant is planned for construction. However, these issues should not present difficulties, particularly if nuclear fission energy production behaves well setting a good example and ITER meets its performance objectives. The availability of suitably trained scientists and engineers may pose problems, but these are being addressed by initiatives such as the European Fusion Training Scheme, which needs to be sustained. Financial barriers, both for ITER and accompanying Research Programmes, will remain as funding is derived from public (national and international) sources with a very limited industrial contribution due to the long term nature of the programme. Increased funding would reduce risks, speed up the Programme and could even allow major changes such as the introduction of EDEM0. However raising the necessary resources will undoubtedly be challenging, as for many first-of-a-kind large scale research infrastructures, the costs of ITER, IFMIF and DEMO are very high, of the order of billions of Euros, with some hundreds of million Euros required to accelerate the research and complete the DEMO design. With such figures, the potential financial obstacles are obvious. Also, any request for

substantial funding for scenarios with accelerated development should not be envisaged until the ITER construction challenges are overcome. There are also scientific and technical barriers, as well as managerial challenges, which manifest themselves in all very large scientific projects, but which are particularly complex when dealing with new frontier technologies in an international context. Although the areas where problems will have to be overcome are numerous, plasma physics and materials engineering will figure high on the list at all stages of the development of fusion technology as detailed in the Fusion Road Map [11]. For example, a full scale DEMO with an expected electrical power output of 800 MW will need about 300g of tritium per day, which can only be supplied by the still-to-be-proven Tritium Breeding Blankets [12].

The present lack of appropriate harmonised European Codes and Standards should also be tackled in due time to avoid further delays in the deployment stages. Lastly, as fusion is now moving from the R to the R&D phase under a multi-national, multi-institutional approach, Intellectual Property Rights (IPR) is also an issue that will need addressing properly.

11.4 Needs

Although the Fusion community has so far been well organised, there is a need to strengthen this organisation to cooperate with industrial partners and complement the development of new technologies by research institutes and universities who currently provide the majority of the effort. To keep a functioning integrated and focussed EU Fusion programme, the EU and its Member States should be encouraged to contribute more, including those who absent themselves from traditional nuclear technologies. Dissemination of information supporting nuclear fusion through targeted PR should be continuous, considering that benefits will only accrue if the general public is regularly addressed. Education and training should be reinforced, academic and research centres brought into line earlier and campaigns of recruitment into the field should be coordinated. In this respect, training and education programmes within the Euratom FP and the Marie Curie Fellowships address this issue, while several Fusion Associations hold summer schools for graduate students and young researchers.

There remains a need to adapt and where appropriate reinforce aspects of the present EU programme to keep an integrated approach, with a view to ensuring success and minimising risk in particular during the construction phase of ITER and the design phase of DEMO. It has been recommended that Europe should set up a DEMO design group, with substantial industrial involvement (technical and managerial), as soon as resources (manpower and money) allow this to be done without a negative impact on ITER. The group would design a buildable DEMO and consider whether EDEMO or other alternatives should be pursued in parallel to ITER and IFMIF. The group should also evaluate the potential of a Component Testing Facility (CTF) and the challenges of constructing such a device and, if it seems desirable, proceed to a detailed design. All these proposals obviously have a resource need as outlined above. Therefore, once ITER construction is well underway, a political will should be sought from an EU unified in its desire to bring fusion power as a reality in the shortest possible timescale.

11.5 Synergies with other sectors

There are important interactions, both at strategic level and in specific technical areas. Strategically, there is obviously an interaction with climate change strategy. Fusion, if successful as hoped, will make a major contribution to the security of energy supplies, and will also contribute to reconciling lowering emissions with continued economic development. It is also important to benefit from synergies and the exchange of know-how with other technology programmes, ranging from the application of fusion power for hydrogen production to materials development programmes. Scientific and technical synergies already exist with several fields and through the SET Plan these should be further developed.

Although fusion and fission power are very different in many respects, there are a number of technical areas where there should be synergies and substantial opportunities to mutually benefit from collaborative programmes, with foci that include: the design and application of high-temperature (radiation-resistant) alloys, safety and licensing issues, helium and liquid metal cooling systems, irradiation facilities, and codes and standards. This synergy becomes even more important when the developments specifically required for GEN III and GEN IV, in particular materials requirements, are elaborated in comparison with those needed for fusion. The EU has introduced some relevant programmes (e.g. PERFECT [13], which brings together multi-scale modelling work in fission and fusion, and EXTREMAT [14], which is focussed on high-heat flux materials), and there is scope for further initiatives on a European scale.

Similarly, developments for advanced fossil-fuel power plants in the Zero Emissions Technology platform require high temperature materials, and work on high heat-flux materials for a variety of applications.

The EERA (Research Alliance) of the SET-Plan has also started reviewing needs and opportunities for research on "nuclear" materials and technologies, which could cross-cut fission and fusion and possibly other energy technologies.

The potential for fusion-based production of hydrogen emphasises the need for a link to the hydrogen and fuel cell activities.

Fusion research requires high performance computing; developments are being prepared in contact with other communities, taking into account the projects of new European infrastructures.

There are other synergies with a number of other scientific domains (including some in the energy sector), e.g. in the areas of turbulence studies, diagnostics techniques (e.g. spectroscopy), and atomic physics (plasma edge phenomena).

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12 ELECTRICITY GRIDS

12.1 Technological state of the art and anticipated developments

The European transmission system is generally defined as the network featuring at least high voltages, typically equal to or higher than 110 – 150 kV, and largely differs from the distribution systems, i.e. the lower voltage networks connecting transmission with final customers, mainly in terms of function, structure and consequent planning and operation philosophies [1, 2].

In order to comply with the energy and climate change policy targets of the EU by 2020, the grids must be capable to host Renewable Energy Sources for Electricity (RES-E) covering at least 30 - 35 % of the EU electricity consumption, cf. 16 % share recorded in 2006. The European transmission and distribution networks also face different challenges, which may push them to evolve following different trends and conflicting drivers. Adjectives such as ‘super’ and ‘smart’ are therefore more and more adopted in correlation with the analyses of future electricity grids to hint at features such as improved adequacy, flexibility, reliability and controllability [1, 3, 4, 5].

12.1.1 Transmission system

The European electricity industry has been moving from a regulated structure dominated by vertically integrated utilities to an unbundled and liberalised one organised in (regional) markets. In most European countries a single Transmission System Operator (TSO) is responsible for operating, maintaining and developing the power grid. The interconnectors between different countries/regions have become a key instrument for the market transactions and the ongoing liberalisation process has led to increasing inter-area power exchanges through them. Signs of lack of adequate interconnection capacity can be found in level, frequency and variability of congestion [1, 2, 6, 7].

Additionally, connections of onshore wind power plants at the transmission level are becoming more frequent in Europe. Further penetration of (onshore and offshore) wind power and other type of RES-E is expected and this variable generation has to be reliably integrated in the European bulk power system [1, 7, 8].

Expanding the network via conventional High Voltage Alternating Current (HVAC) lines or cables is one of the solutions typically pursued to provide the European grid with higher transfer capacities and lower electricity losses. Equipment costs² for HVAC 400 kV transmission lines amount to 400 – 700 k€/km for a single circuit and to 500 – 1 000 k€/km for a double circuit. Equipment costs for HVAC transmission cables may vary greatly in a range between 1 000 and 5 000 k€/km [7, 9].

To circumvent the problems restraining the construction/replacement of traditional electricity infrastructures, a number of promising non-standard technologies, currently available with a diverse degree of maturity, can be also deployed [6, 7, 9, 10, 11]:

- **HVDC (High Voltage Direct Current)** systems are transmission technologies already mature for specific applications: long distance lines, undersea links and asynchronous systems interconnection. Recent advances in power electronics, coupled with traditional features of HVDC, should help this technology to deploy further, with the aim to improve the operation and support the development of onshore and, possibly, offshore European transmission grids. This is particularly the case of the Voltage Source Converter (VSC)-based HVDC system, which displays

² Typical rating and installation conditions are considered for both standard and non-standard transmission technologies. Capital expenditures for transmission technologies are highly dependent on different parameters such as the equipment rating, the operating voltage, the local environmental characteristics and material/manpower costs.

a higher flexibility and a wider range of active and reactive power control and easier expansion to multi-terminal configurations³. Equipment costs for HVDC transmission lines and cables can amount to 300 - 400 k€/km and 1 000 – 2 500 k€/km, respectively. These figures do not include the HVDC converter costs: a classic HVDC converter may cost 40 – 70 k€/MW, while expenses for a VSC-HVDC converter may reach 50 – 80 k€/MW [7, 10, 12, 13].

- **FACTS (Flexible AC Transmission Systems)** are power electronics-based devices aiming to attain a more efficient use of the existing transmission facilities, thus reducing the need for constructing new transmission lines. Their features include active and reactive power control, dynamic reactive power support and voltage control. Equipment costs for FACTS may also vary greatly due to the different control features and configurations of such devices. For these reasons, a cost range of 30 – 170 k€/MVA for the commercially available devices rating is currently estimated [7, 10].
- **New types of conductors**, such as Gas Insulated Lines (GIL) and High Temperature Superconducting (HTS) wires, are mainly installed at the demonstration level with encouraging results in terms of lower electricity losses and higher transfer capacities. GIL cost is estimated at 4 – 9 M€/km. For HTS technology, costs of around 150 €/kA-m are reported for the first generation wires [14, 15].

It has to be noted that in a highly meshed network, as in Europe, if HVDC and FACTS become extensively deployed⁴, they will deliver real benefits only when subjected to a coordinated and hierarchical control. This in turn requires a wide-area, real-time information gathering and analysis system.

Software and Information and Communication Technology (ICT) can contribute as well to increase the adequacy and robustness of the system, thus reducing the need for building new infrastructures, as well as augmenting its monitoring and governing. Dynamic thermal power rating techniques intend to exploit favourable ambient conditions (low temperatures) to temporarily overload conductors without risks of mechanical and thermal stress. Wide Area Monitoring Systems (WAMS) aim to monitor, assess and optimise the power flows across the whole system, by means of large scale satellite-based measurements [6, 7].

12.1.2 Distribution systems

Similarly to the TSOs, a large number of Distribution System Operators (DSOs), following dedicated unbundling provisions, have become or are in the process of becoming independent from the former vertically integrated utilities. The features of the distribution systems vary markedly throughout Europe. Costs for distribution networks equipment are significantly lower than those ones of transmission (about or less than a tenth for overhead lines and about or less than a thirtieth for cables), but a much larger number of components are needed to build the distribution systems. Traditionally, distribution grids have mainly been designed and operated to distribute power passively from the upstream generation and transmission system to the final customers. In this situation, with power flows mainly going mono-directionally from the substations to the consumers, the DSOs did not have the opportunity or the need to take active control of the power flows, unlike the TSOs for the transmission grids [2, 3, 4, 16].

³ Demonstrating the VSC-HVDC's potential for large sized installations is one of the objectives of the Kriegers Flak pilot project, which investigates the feasibility of constructing an offshore electricity transmission grid simultaneously linking the electricity grids of Denmark, Sweden and Germany and connecting large offshore wind farms (up to 1800 MW capacity) [36].

⁴ This coordination problem already begins to surface in some regions due to the deployment of phase-shifting transformers (PST), which are electro-mechanical devices, typically used to control active power flows, with similar but more limited features in comparison to FACTS.

The distribution networks face an increasing deployment of small-sized power plants, called Distributed Generation (DG) units⁵, and more generally, of Distributed Energy Resources (DER), i.e. demand- and supply-side resources, including DG units and storage technologies. On the one hand, this is due to the steady technological progress on small-sized cogeneration (CHP, Combined Heat and Power) and RES-E generation and, on the other hand, to the ongoing or expected diffusion of other electricity applications, e.g. electric vehicles. When increasing numbers of DER, capable to inject power, i.e. DG or storage units, are connected to the distribution grid, electricity can also be transferred reversely, flowing from the dispersed units to the distribution and the upstream transmission. In this new condition, the distribution may change control properties and become more similar to the transmission, that is, have more ‘active’ control features [2, 3, 6, 7, 17, 18].

The access to the distribution networks of DER in general and DG in particular is still largely based on the “fit and forget” principle. The units are allowed to connect/operate without an accurate and continuous control of their impact on network operation. Even if a certain amount of DER can be accommodated by today’s distribution system, a massive deployment of DER calls for new operation philosophies, revised design criteria and upgraded architecture concepts⁶. If DER units reach significant penetration levels and cover a substantial amount of demand, they need to be fully integrated into the system management. Hence, they have to participate in system control and in provision of reserves, similarly to large conventional power stations. As an example, even if a large penetration of electric vehicles can strongly affect the distribution grids architecture and operation, it can also help in optimising the power system management [2, 7, 17, 18].

Improving the monitoring and control of the networks through the deployment of metering, telecommunication and remote control technologies is also conducive to a more secure and reliable grid operation with increased share of DER. An enhanced data exchange, with dedicated ICT platforms supervising the information flows between the electricity system players, may strengthen the capabilities of real-time trading, fault prevention, asset management, generation control and demand side participation. In particular, installation of smart meters coupled with demand side energy management measures may rationalise energy consumptions and make the load more responsive and flexible. The development and improvement of cost-effective and coordinated high-power energy storage systems will also play a vital role in facilitating a larger penetration of DER by decoupling generation and energy use⁷ [2, 6, 7, 17, 18].

12.1.3 Transmission-distribution interfaces

The indirect effects of DG growth on the European transmission system cannot be neglected. Recent disturbance and disruption events in Europe prove that, without properly coordinated system interfaces and flexible controlling devices, the consequences of a power disruption at the distribution level may be suffered (if not amplified) at the transmission level [2, 19, 20].

In general, TSOs and DSOs still have to devise strategies to address in a systematic way the interface issues deriving from developments towards smart grid concepts. In order to make the transmission and distribution grids work together efficiently and safely, an increased coordination in their development

⁵ These DG plants currently reach 25 – 30 % shares (of the installed generation capacity) in a few forerunner countries.

⁶ These changes are already happening in some countries: as an example, renewable energy systems with an installed capacity larger than 100 kWp are already required to be included in the active grid control operations of the local energy provider [37].

⁷ Several pilot projects, to test innovative integrated network solutions on the distribution grids, have started or about to start. Just to give a few examples: in the Malaga SmartCity Plan RES-E will be linked to a Spanish distribution grid, along with electricity storage and recharging stations for electric vehicles, targeting 20 % energy savings for 11 000 customers; the Advanced Metering Infrastructure project foresees the deployment of 90 000 smart meters in a Gothenburg’s area to perform real-time monitoring and data exchange; the Portuguese InovGrid project aims to achieve a 20% cut on the clients’ electricity bill thanks to household energy boxes providing for efficient consumption (and micro-generation) management [38, 39, 40].

and operation must be actively pursued. Both transmission and distribution need to be further developed, not only in terms of carrying capacity but also via advanced ICT infrastructure and communication and control platforms⁸ [2, 6, 7, 18].

12.2 Market and industry status and potential

The European transmission and distribution grids are estimated to stretch over some 230 000 km high voltage and 1 500 000 km low/medium voltage lines. These networks are aging, they accommodate mostly large centralised production and they feature weak interconnections. Additionally, these grids currently face mounting network congestions, increasing deployment of RES-E and more efficient generation units. They have to cope with the rising diffusion of DER. This may bring about risks of deterioration of reliability and security of supply [8, 10, 21].

As a consequence, flexible, coordinated and adequate electricity networks, designed according to new architectural schemes and embedding innovative technological solutions, are keys to address the above challenges [2, 6].

The 2008 International Energy Agency (IEA) Reference Scenario for Europe quotes investments in excess of EUR 1.5 trillion over 2007 - 2030 in order to revamp the electrical system from generation (two thirds of the investment) to transmission and distribution (one third). ENTSO-E (European Network of Transmission System Operators for Electricity) estimates investments for transmission and distribution of the order of EUR 500 billion by 2030. In its turn, distribution needs account for 75 %, against 25 % for transmission, of the investment expected on electricity grids. EUR 17 billion are to be spent in electricity networks between 2008 and 2012, according to UCTE (Union for the Co-ordination of Transmission of Electricity, now incorporated in ENTSO-E), to increase the European transmission interconnection capacity⁹ [1, 22, 23, 24].

The European electrical and electronic engineering industry has currently a strong market leadership¹⁰ on products, equipment and systems. This sector has still considerable potential for growth and employment through higher investment and innovation in key EU customer markets and for keeping the industry's international leadership in many areas. This potential can be achieved also by R&D programmes, technology roadmaps and innovation policies supporting early demonstration projects and by maintaining/creating lead customer markets to foster early development and application of new technologies in Europe, for example, in the field of energy efficiency and renewable energy) [12, 25].

12.3 Barriers

The main barriers hindering the development of the present grids and the design of future electricity networks are to be found in the inadequacy of the current regulatory framework, the low degree of technical and research coordination and the increasing social opposition to new installations [6, 26].

Investments appear distorted as a result of insufficient unbundling. The present regulations do not adequately promote investments in grid development, especially when it comes to cross-border

⁸ *One of the most promising demonstration initiatives on this front is the Cell Project. A new intelligent concept is being set up in a Danish distribution grid to monitor and control all the connected plants (substations, local CHP and wind turbines). A system control unit (called 'cell controller') will activate the DG units in a certain area ('cell') and aggregate them in so-called virtual generators. The technology will allow the virtual generators to place bids in the market and offer ancillary services such as reactive power control as well as voltage and frequency control [41].*

⁹ *The European Energy Programme for Recovery (EEPR), aiming to provide financial impulse to economic recovery, security of energy supply and reduction of greenhouse gas emissions, established to finance the following sub-programmes for 2009 and 2010: gas and electricity infrastructure projects for EUR 2 365 million; offshore wind energy projects for EUR 565 million; carbon capture and storage projects for EUR 1 050 million [42].*

¹⁰ *The industry represents one of Europe's most important manufacturing sectors, with a turnover of nearly EUR 320 billion annually and an employment of some 2.8 million people in more than 18 000 companies in 2006 [12].*

expansion. The network operators have few incentives to develop the grid in the overall market interest and investment decisions of vertically integrated companies are biased to the needs of supply affiliates. Furthermore, securing long-term financing for networks may be challenging and the lack of stable regulatory framework discourages investment [6, 27].

Regulations and standardisation covering grid issues are either not harmonised or lack in national laws and codes. EU research is fragmented and driven by short-term profit visions. Streamlined and simplified cooperation procedures and tools between different stakeholders, e.g. RES-E producers, TSOs, DSOs and research institutes, are missing. Coordinated procedures and common tools, e.g. on the development of reliability and probabilistic security criteria, on network management and planning techniques, are sometimes not shared and agreed upon by the same TSOs [6, 26].

The bulk power system expansion is curbed by techno-economic, environmental and social issues. As an example, the lack of a developed and verified technical solution for multi-terminal HVDC is a barrier for the development of meshed offshore grids, as well as for the creation of an integrated European transmission grid. Social acceptance of electricity infrastructures is steadily declining and the resistance of local authorities and/or public opinion to new lines is persistently high. The time required to get permits for grid facilities is generally much longer than the time needed to build new power plants (by at least a factor of 3 to 5). Additionally, a shortage of qualified workforce is recorded in the EU [6, 7, 18, 26].

12.4 Needs

Transmission and distribution expansion planning criteria crucially need to be revised and more robust methodologies for network planning must be pursued. Developing harmonised EU transmission grid codes is a clear need for the electricity system.¹¹ Equally important, establishing common technical guidelines for the DSOs would facilitate the market emergence and the technological evolution of the distribution networks. The necessity to clearly define the borders between electricity transmission and distribution is also envisaged [7, 18, 19, 28, 29, 30].

There is a need to set out standard rules and guidelines on one side and a need for removal of administrative barriers (harmonisation/certification schemes) on the other, in order to control the system evolution from the present numerous and varied national-based networks towards a common European electricity system. The development of standards, especially related to communication, smart metering, network integration and grid connections to facilitate interoperability and foster DER integration at a lower cost is necessary. Market structure and mechanisms should be implemented to support innovative technology deployment, e.g. Smart Metering, FACTS. Social acceptance of electricity infrastructures should be improved. The permit procedures need to be streamlined in order to accelerate the modernisation of aging grid infrastructures [6, 7, 18, 29].

Further research programmes encompassing technical, market and regulatory challenges are needed. Investment shares borne by each TSO/country for cross border links must be properly and carefully defined to achieve a truly pan-European network. Also demonstration projects are vital in driving the smart grid concepts forward. By drawing upon results achieved by previous projects, large-scale demonstrations, involving a high number of sites and real communities, are needed to prove the up-scaling and reliability of technical / market / regulation solutions for RES-E/DER integration and to better understand the social interactions with and reaction to innovative technologies and systems [3, 5, 8, 18, 20].

¹¹ As an example, the connection of new generation (especially wind farms) is also influenced by the way the grid connection costs are borne and split between the involved parties; how to discriminate investments required for grid reinforcement and for generation connection still finds diversified approaches and solutions across the EU.

More electrical engineers are also required to ensure new knowledge and expertise to EU research and industry. Demonstration projects may also be instrumental to foster growth and employment of the EU electrical and electronic engineering industry [3, 8, 12, 18].

It is finally noted that the combined provisions and initiatives of the third EU energy package and of the Strategic Energy Technology Plan aim to address and satisfy large part of the above described needs [7, 8].

12.5 Synergies with other sectors

The electricity generation, network and consumption stakeholders should work together in conceiving the future European electricity system. Only by reaching views by consensus, effective solutions to some critical issues can be devised. For example, those related to cost sharing for grid connection and grid development investments, or those linked with the definition of common standards and operation rules. RES-E penetration in the network can be amplified, as soon as common regulations governing the European electricity systems, e.g. grid access and operation rules, are put in place and real-time monitoring mechanisms aiding the transmission and distribution operators are set up. From a planning and operational point of view, all the available technologies (including demand side management, storage and distributed generation) shall contribute to balance the bulk power system, in order to ensure security and reliability of supply [6, 12, 19, 26, 31].

EU-wide collaborative research and demonstration on RES-E and DER integration enablers, such as storage, ICT and metering, is essential to make these technologies viable from the technical/economic point of view. The diffusion of information technologies throughout the electricity system may profoundly change the assumptions on which the traditional system was built. Control and generation of electricity may be distributed throughout the power network, with a fleet of properly coordinated smart appliances and loads able to adjust to grid conditions, thereby optimising the system operation [6].

Offshore projects can represent an opportunity for creating links that both connect generation capacity and increase the transmission interconnection between different regional markets. Such potential synergies face the complexities of dealing with different planning, regulatory and market regimes [31, 32, 33, 34, 35].

Finally, synergies should also be sought with other EU networked infrastructures, such as telecommunications, transport and environmental infrastructures, e.g. combining power lines with land transport infrastructures such as railways or roads [8].

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13 BIOENERGY – POWER AND HEAT GENERATION

13.1 Technological state of the art and anticipated developments

Several technologies are available for energy conversion from biomass to heat and electricity, based on two main process technologies: thermo-chemical (combustion, pyrolysis and gasification) and bio-chemical/biological (digestion and fermentation). Bioenergy technologies are in different stages of development: from commercial status (biomass combustion, biogas production) to near commercial and demonstration (thermal gasification) to research and pilot stage (pyrolysis).

A wide range of biomass materials can be used to generate bioenergy: fuelwood, wood residues, forest residues, agricultural waste and residues (straw, stalks, animal manure), residues from food and paper industries, municipal solid wastes (MSW), sewage sludge and dedicated energy crops, such as Short Rotation Forestry/Short Rotation Coppice (willow, poplar, eucalyptus) and energy grasses (miscanthus, reed canary grass, switchgrass). Traditional biomass, including wood fuel, continues to be an important source of energy. New compacted forms of better quality biomass, such as wood pellets and briquettes, are increasingly used, despite their higher cost. Large scale plants currently use straw (in Denmark, UK and Spain, with plant capacities up to 38 MW_e) and forestry residues (Finland and Sweden with capacities up to 50 MW_e).

Most biomass technologies have difficulties to compete with fossil fuels. The diversity of feedstock creates technical and economic challenges for operation due to the different physical and thermochemical characteristics and due to the fuel costs. However, substantial operational experience has been gained and production costs have been reduced. Several biomass options, such as large-scale combustion of organic waste and residues, are already providing energy at a competitive price:

- **Biomass combustion:** Bioenergy production is largely based on a mature, direct combustion boiler and steam turbine technology. Biomass combustion produces heat, electricity or Combined Heat and Power (CHP) at small scale and large scale for residential and industrial applications. Key sectors for biomass combustion are the pulp and paper and wood industries, using black liquor, waste incineration, wood and agricultural residues. Technology development has led to efficient, industrial-scale heat production and District Heating (DH) systems, with efficiencies of 70 – 90 % in advanced systems. DH is very efficient and flexible system for large scale heat production for residential and commercial use, based on heat-only boilers, CHP or residual heat from industrial processes. Traditional use of biomass in households is based on fireplaces and stoves using mainly wooden logs. However, household systems are largely outdated, with low efficiency and the source of high particulate emissions. A significant, dynamic market for biomass pellets has been expanding with 18 % growth per year worldwide, reaching 6 Mt pellets used in the EU in 2007, and 5.3 Mt in 2008, out of 10 Mt produced worldwide in 2007 [1, 2]. Pellets are used in automated small, medium and large scale, residential and commercial boilers for heat, power and CHP production, mainly in Sweden, Denmark, Germany, Belgium, Austria and Italy.

Common biomass boiler designs are stationary, travelling grate and atmospheric fluidised bed boilers. Biomass combustion is suitable for a large range of capacity plants, from very small scale of a few kW to large-scale power plants up to 100 MW_e. Biomass heating plants range from a few kW for classic fireplaces and stoves, with a very low efficiency (10 – 30 %) to 1 – 10 MW_{th} for heat boilers with efficiencies of 70 – 90 %. CHP plants have a typical capacity of 1 – 50 MW_e with overall efficiencies of 80 – 90 %, while electricity plants have 10 - 50 MW_e capacity with 25 – 35 % electrical efficiencies. The Fluidised Bed Combustion (FBC) technology allows electrical efficiencies of 30 – 40 %. Higher efficiencies are obtained in higher capacity plants over 100 MWe or in biomass co-firing in coal power plants [3, 4, 5, 6].

The capital cost of a biomass heat plant range from 300 to 700 €/kW_{th}. The capital cost of a grate or fluidised bed boiler with a steam turbine is estimated to be in the 2 500 – 3 500 €/kW_e range [3, 7, 8, 9, 10]. The biomass plants, using complex feeding systems, require higher capital cost and higher operating costs, leading to low-cost effectiveness. Such plants are cost effective only when the biomass is available at low costs, when carbon tax or incentives are in place. The use of higher performance cycles (multi-pressure, reheat and regenerative steam turbine and supercritical steam cycles) is expected to increase the plant efficiency by up to 10% compared to the present systems.

- **Biomass co-firing:** Biomass and municipal solid waste (MSW) co-firing with coal in existing boilers is a low cost option for the use of biomass. This is an attractive option for GHG emissions mitigation by substituting biomass for coal. Biomass co-firing is adequate for a variety of technologies, such as spreader stoker boilers, pulverized coal boilers and fluidised bed boilers. Biomass substitution can reach 10 – 15 % of the total energy input, with small system modifications required for the burner and feeding system. Biomass co-firing in coal fired power plants is an especially attractive option due to the high conversion efficiency and low investment cost required [11]. Biomass co-firing with coal in large-scale coal plants is claimed to have significantly higher combustion efficiency (30 – 40 %) than dedicated biomass plants (typically 25 – 35 % for biomass and 22 % for MSW). The capital cost for retrofitting an existing coal power plant to be used for biomass co-firing is much lower than a biomass plant, estimated at 150 – 300 €/kW_e of biomass [3, 8, 12].
- **Anaerobic Digestion:** Anaerobic digestion is the conversion of organic material to biogas by bacteria, in an anaerobic environment. This process is particularly suitable for a range of wet biomass feedstocks: agricultural, household and industrial organic wastes, sewage, manure, animal fats, slaughtering residues, etc., as well as agricultural crop residues. Biogas is a mixture of methane and carbon dioxide with small quantities of other gases, such as hydrogen sulphide. Due to the relatively low methane content (60 – 70 %) and high content of contaminants, biogas might require treatment to remove water and hydrogen sulphide, depending on feedstock. Biogas can be upgraded to higher quality gas, by the removal of carbon dioxide, to enhance its methane content. The conversion of various wastes and manure to biogas can bring significant environmental and health benefits while providing a valuable fertiliser [13]. The solid residue of anaerobic digestion can be used as a fertiliser in agriculture. However, risks derived from the accumulation of heavy metals (Cu, Zn, Fe and Cr) in the digestate must be considered, and its use as fertiliser might have restrictions due to legal requirements.

Anaerobic digestion is a commercial technology. However, research could still improve the overall process, monitoring and control systems. Biogas is produced in farm scale units, centralised co-digestion units or at landfill sites. Anaerobic digestion is widely used in many countries in small capacity plants in rural areas. The process has been demonstrated also and applied commercially in industry to process sewage sludge or waste water with high loads of organic matter. Biogas can be used for local heating, district heating or CHP in small capacity plants in boilers, internal combustion engines and gas turbines. Biogas has been used also in transportation after treatment and compression. The capacity of a biogas and CHP plant ranges from 250 kW_e to 2.5 MW_e, at conversion efficiencies to electricity between 25 – 35 %. The capital cost of a biogas plant with a gas engine or turbine is estimated to be in the range of 2 500 – 5 000 €/kW_e [10, 12, 14].

- **Landfill gas utilisation:** Landfill sites (more than 150 000 landfills in Europe, according to [15]) are a specific source of methane rich gas. Landfill gas contains about 40 – 60 % methane, the remainder being carbon dioxide and trace gases, such as nitrogen, oxygen, water, hydrogen sulphide and other organic contaminants. Landfill sites can produce gas over a 20 - 25 year lifetime. Collecting this gas can contribute significantly to the reduction of methane emissions [13]. The collection of landfill gas and production of heat and/or electricity in boilers and gas

engines is technically possible and economically viable and the application of such systems has been deployed on a large scale in the EU (500 landfill gas plants in Europe). For example, landfill gas counts for about 3 Mtoe out of 6 Mtoe of biogas produced in the EU in 2007, especially in the UK, followed by Germany, Italy and France [16]. Collected gas requires cleaning to remove moisture and contaminants. However, due to the requirements to reduce landfilling (Landfill directive 1999/31/EC), landfill gas is expected to decrease over time in the EU. The plant capacity of landfill gas collection varies from a few tens of kW to 4 – 6 MW, typically several hundreds kW_e, depending on the size of the landfill site. The capital cost of a plant coupled with a gas engine or turbine is estimated to be in the 1 200 – 2 500 €/kW_e range, at conversion efficiency to electricity up to 25 – 35 % [10, 12, 17].

- **Biomass gasification:** Gasification is thermo-chemical conversion of biomass into a combustible gas by partial oxidation at high temperatures. Biomass gasification has not yet reached technical and commercial maturity and is still in a demonstration phase and close to commercialisation. Despite many efforts, the commercial status is still not achieved for several technical and non-technical reasons. Biomass gasification is still relatively expensive and faces economic and other non-technical barriers. There are several gasification concepts available, based on the gasification medium (air, oxygen or steam), operating pressure (atmospheric or pressurised) and type (fixed bed, fluidised bed or entrained flow gasifier). Fuel gas can be used for heat and/or electricity production, synthesis of transport biofuels (hydrogen, methanol or synthetic diesel via the Fischer-Tropsch process) and chemicals production in Biorefineries. Air gasification typically produces a syngas with a relatively high concentration of N₂ with a low heating value (4 – 6 MJ/Nm³). Oxygen and steam-based gasifiers produce a syngas with a relatively high concentration of H₂ and CO and higher heating value (10 – 12 MJ/m³ for oxygen gasification and 15 – 20 MJ/m³ for steam gasification). Syngas can be used for heat and/or electricity production, synthesis of transport fuels (hydrogen, methanol or synthetic diesel via the Fischer-Tropsch process) and chemicals.

The Biomass Integrated Gasification/Combined Cycle (BIG/CC) is a promising, high-efficiency technology, although more complex and costly, for syngas generation and conversion to energy in a gas/steam turbine cycle. A complex gas purification system is needed for hot gas particulate and tar removal. The removal of N, S, Cl and other trace elements (Na, K) released from biomass during gasification is required. The syngas produced is then used in gas engines or gas turbines to produce heat and electricity. Syngas from biomass can be used for methanol and hydrogen production as fuels for transportation. Biomass gasification is also appropriate to provide fuel for fuel cell systems [18].

Typical capacities range from small capacity of a few hundred kW_e for heat production, 100 kW_e – 1 MW_e for CHP with a gas engine to high capacity of 30 – 100 MW_e for BIG/CC. Various concepts are available for different plant capacities. Fixed-bed gasification is adequate for small-scale gasification reactors (ranging from tens of kW_{th} to 1 MW_{th}), while fluidised bed gasification is adequate for larger scale gasification. Atmospheric downdraft gasifiers are suitable for small scale up to about 1.5 MW_{th}, while atmospheric updraft gasifiers are suitable for units up to 2.5 MW_e. Stationary fluidised bed gasifiers are suitable for small to medium scale up to about 25 MW_{th} and circulating fluidised bed gasifiers are adequate from a few MW_{th} up to 100 MW_{th}. BIG/CC ensures high electrical conversion efficiency of 40 – 50 % for 30 – 100 MW plant capacity. In cogeneration, total plant overall efficiency can reach 80 – 90 % [3, 5, 6].

Demonstration projects were developed in several countries based on various gasification concepts, such as a pressurized BIG/CC unit in the BIOFLOW pilot project in Sweden or the atmospheric BIG/CC system in the ARBRE project in UK. However, the operation of these projects proved to be difficult and they were closed down. Small gasifier and gas engines units of 100 – 500 kW_e

capacity are about to become available on the market. The operation difficulties and high capital and operation costs have so far prevented the deployment of small-scale gasification. The competition from co-firing and biomass combustion also hampered the development of the gasification technology [3, 19]. The capital cost of a gasification plant using diesel engine or gas turbine (50 kW_e – 30 MW) is estimated to be in the 2 500 – 3 500 €/kW_e range for conversion efficiencies to electricity of 30 – 40 %. The capital cost of a biomass gasification plant with combined cycle (30 – 100 MW_e) is estimated at 3 500 – 5 000 €/kW_e, for conversion efficiencies to electricity of 40 – 50 % [3, 8, 20].

- **Pyrolysis:** Pyrolysis is the conversion of biomass to liquid, solid and gaseous fractions, in the absence of air at temperatures around 450 – 600 °C. Fast pyrolysis, at moderate temperature (450 – 500 °C) and short residence times (< 5 s), for bio-oil production (heating value of about 17 MJ/kg) is currently of particular interest. Fast pyrolysis and bio-oil production enables the conversion of biomass with an efficiency of up to 80 %. Bio-oil can be upgraded to biofuels or to intermediates that can be used in biorefinery. Bio-oil can be used in boilers, engines and turbines for heat and/or electricity generation and can be used as transport fuel after upgrading or used to extract chemicals. Upgrading pyrolysis oil and removing alkalis and catalytic cracking of the oil are required for certain applications. Pyrolysis and upgrading technology is not commercially available and is presently less developed than gasification, although considerable experience has been gained and several pilot plants or demonstration projects are in operation. Pyrolysis now receives attention as a pre-treatment step for biomass gasification [5, 6, 18]. Research is needed on the conversion process, on the quality and subsequent use of the bio-oil, to overcome various problems related to thermal stability and process reliability. The improvement of the cost-effectiveness of the process is a key issue.

13.2 Market and industry status and potential

Biomass plays an important role in energy generation in the EU-27, almost 5 % of the EU gross energy demand being covered by biomass resources. The contribution of biomass was almost two-thirds (65.6 %) of all renewable primary energy consumption in 2007. However, the share of biomass in the energy mix differs widely from MS to MS: from 1.3 % in the United Kingdom to 29.8 % in Latvia. Bioenergy production reached 86.6 Mtoe in 2007: 66.4 Mtoe from solid biomass, 6 Mtoe from biogas, 6.1 Mtoe from municipal solid waste (MSW) and 8.1 Mtoe from biofuels. Solid biomass use for energy increased from 44.8 Mtoe in 1995 to 66.4 Mtoe in 2007, an increase of 21.6 Mtoe (48 %) [16]. Wood and residues from forestry and wood processing are the main source for bioenergy (85 %), followed by waste (10 %) and by agricultural biomass (5 %). Of the total biomass, 66 % is used for heat production, 31 % for electricity and cogeneration and 3 % for liquid fuels [21].

The renewable electricity production steadily increased, based on the support provided: feed-in tariffs in most of the MS (with the highest success in Germany, Denmark and Spain); quota obligations combined with green certificates in 7 MS (Belgium, Italy, Latvia, Poland, Romania, Sweden and UK); fiscal incentives, such as tax exemption or energy taxes (UK, Finland, Slovenia and Malta); and the tender scheme (France) [22]. The bioenergy installed power capacity in 2007 was 14.1 GW wood/wood wastes, 5.4 GW municipal solid wastes and 3.7 GW biogas plants. Gross electricity production in the EU-27 reached 49 171 GWh from solid biomass, 19 932 GWh from biogas and 13 999 GWh from MSW in 2007 [16].

The market for renewable heating (biomass, solar thermal and geothermal) has a substantial potential for growth since the heating and cooling sector represent about 50 % of the final energy consumption. Data on heat production is difficult to determine, due to the lack of available statistics on heat data usage, excluding the biomass, for domestic heating appliances. Biomass dominates renewable heating, mainly in domestic heating, with a contribution of 60 Mtoe out of a total of 61.5 Mtoe in 2006

in heat production. The RES heat represented 10.8 % of 570 Mtoe of total heat generation in the EU in 2006. In the EU-27, only 1 % of the heat demand is covered by district heat coming from biomass. In a few countries, such as Sweden, Finland, Denmark, the Baltic countries and Austria, this share ranges between 5 – 30 %.

The growth in the use of biomass for heating and cooling has been rather slow compared to the growth rates in the renewable electricity and transport sectors [23]. Biomass consumption for heat generation increased from 40 Mtoe in 1997 to 51.2 Mtoe in 2002 and to 60 Mtoe in 2006, meaning a 20 Mtoe growth or a 5 % growth rate each year [24, 25]. Biofuels consumption in the EU increased from 0.5 Mtoe in 1997 to 1.3 Mtoe in 2002 and to 8.4 Mtoe in 2007, with a growth of 7.9 Mtoe [16]. This is due mainly to the lack of legislation supporting heating and cooling from renewable sources before the adoption of the new RES Directive 2009/28/EC.

Biomass must play a crucial role in meeting the 20 % target for renewables by 2020 and GHG emissions reduction in the EU-27. Biomass is expected to contribute to around two-thirds of the renewable energy share in 2020 according to PRIMES projections (SEC(2009) 503 final). About 236 Mtoe of biomass can be theoretically available in 2020 and 295 Mtoe by 2030 in the EU, in sustainable conditions [26], while, according to AEBIOM, the contribution of biomass can be increased to 220 Mtoe in 2020 [21]. The EREC EU Technology Roadmap estimates that biomass can contribute by 175.5 Mtoe to the primary energy supply, covering 12.7-13.9% of total final energy consumption. These estimates are based on a moderate annual growth scenario for different technologies and the European energy and transport: trends to 2030 - update 2007 [19]. The expected installed capacity of biomass power plants in the EU-27 is up to 42 GWe by 2020 and 52 GWe by 2030.

13.3 Barriers

The cost competitiveness of bioenergy production remains a key barrier in the deployment of biomass technologies. Member States have encouraged the use of biomass for electricity and heat through various measures, such as research programmes, tax reduction and exemptions, investment subsidies and feed-in tariffs for renewable electricity. The various incentives were the key elements for bioenergy deployment. Since bioenergy technologies require significant investments, the lack of long-term policies was the main factor that discouraged long-term investments in bioenergy technologies, and prevented their deployment at the larger scale.

Bioenergy technologies still have to overcome a number of technical and non-technical barriers for their commercial application. Deployment of bioenergy requires demonstration projects at a relevant industrial scale, which are costly but crucial for improving and certifying technical performance and to achieve cost reduction.

The sustainable biomass production and reliable supply of feedstocks is a critical success factor for large scale deployment of bioenergy technologies. Biomass mobilisation needs to be enhanced. Competition between alternative use of biomass resources for food, feed, fiber and fuel is a problem and limitation for bioenergy deployment. An appropriate assessment of the biomass resources, which takes into account various environmental constraints and competitive uses, is the key issue. The logistics related to high biomass volumes required (transport, storage requirements) are crucial for the operation of bioenergy plants. Biomass resources are a limiting factor for the plant size, determining the collection radius and economics of the plant, depending on location. Large-scale production of energy crops (SRC/SRF and energy grasses) can be a solution for increased biomass supply due to their favourable economic and environmental characteristics.

13.4 Needs

Further research is needed to establish various bioenergy technologies, to develop better approaches to improve bioenergy production and system integration and to increase cost effectiveness. There is a crucial need to demonstrate and scale-up bioenergy technologies at a relevant industrial scale. Technological development is expected to improve process efficiency in direct combustion, gasification systems, anaerobic digestion, gas treatment and the introduction of higher performance Organic Rankine Cycles (ORC), steam cycles and biomass gasification combined cycle systems.

Investment in research and a better coordination of and more focused research efforts at the EU and national levels is important. More research effort should be devoted to upstream areas, such as feedstock production, as improvements in feedstock and biomass supply logistics can contribute to overcome the problems related to the variability of physical and chemical properties of biomass feedstock.

There is a need for a harmonisation and increased coherence between the Common Agricultural Policy, Forestry policies, and Energy and Climate Change policies. Coordination with the non-energy based biomass industry, but also between biomass use for heat and electricity and for biofuels is of prime importance. A cross-sectoral coordination between agriculture, forestry, pulp and paper and wood processing industry is required.

A long term and coherent policy framework and an innovative financing mechanism need to be put into place before the technology reaches commercial maturity. An overall harmonisation of incentives and regulations across the EU, with a view to avoid market distortion and promote competition, is needed too. For biomass feedstock supply, a long term framework is essential.

13.5 Synergies with other sectors

Bioenergy can contribute to diversifying energy supply, reducing GHG emissions, employment and rural development [27]. There are synergies between the Common Agricultural Policy (CAP), Forestry policies, rural development, industrial and trade policies. There is competition for the biomass feedstock with other sectors, such as the pulp and paper and wood processing industry. Competition is expected also between biomass use for heat and electricity and for lignocellulosic biofuels.

Bioenergy complements other RES technologies. Exchange of technological know-how with other energy producing industries could facilitate technological progress and economies of scale (combustion, gasification equipment, gas purification and system integration). Bioenergy must become cost effective with all energy technologies and compete for electricity generation. Possible synergies include: solar thermal systems for the supply of low temperature heat and cooling; geothermal sector for use of geothermal heat; cogeneration systems; buildings sector for the integration of solar systems and fuel cells. Bioenergy faces similar challenges to distributed electricity generation and other RES electricity technologies, such as access to the grid, and requires a decentralised heat and power supply approach, contributing to the district heating and cooling and electricity networks in a similar way.

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14 BIOFUELS FOR THE TRANSPORT SECTOR

14.1 Technological state of the art and anticipated developments

Biofuels are transportation fuels derived from agriculture, forestry or other organic feedstocks. Bioethanol and biodiesel are the most common biofuels used in transport worldwide. Other biofuels are also in use, such as pure vegetable oil and biogas, although with a more limited scope. The main drivers for biofuels production and use are the security of energy supply, diversification of energy supply, reduction of oil import and oil dependence, rural development and GHG emissions reduction.

The production of *first generation biofuels* from starch, sugar-based and oil-seed crops is characterised by commercial markets and mature technologies. First generation bioethanol production is a well established, mature technology, based on a fermentation process of starch and sugar-based food crops, followed by distillation. Bioethanol is produced from a wide variety of feedstock, but is mainly produced from sugar cane (Brazil), wheat and sugar beet (EU) and maize (US). The ethanol productivity per land area is, in the EU, in the order of 1 – 2 toe ethanol/ha for cereals as feedstock and 2 – 3 toe ethanol/ha for sugar beet.

Biodiesel production from vegetable oil and fats is based on a relatively simple and mature technology. Oil-seed crops (rapeseed, sunflower, soya bean, oil palm) can be converted into methyl esters (biodiesel), which can either be blended with conventional diesel or used as pure biodiesel. Rapeseed is the main raw material for biodiesel production in the EU, soya bean in US and Brazil and oil palm in Malaysia and Indonesia. The biodiesel productivity per land area from different oil-seed crops in the EU amount to 0.8 to 1.2 toe biodiesel/ha, while oil palm yields about 3.8 – 4 toe of biodiesel/ha.

Biofuel blending limits in the EU are set according to conventional fuel standards, designed to ensure a compatibility with conventional power trains and refuelling infrastructure. Bioethanol can be used in petrol engines either at low blends (up to 10 %), in high blends in Flexible Fuel Vehicles, in pure form in adapted engines or as a petrol additive (15 %) after being converted to ethyl-tertiary-butyl-ether (ETBE). Flexible fuel vehicles, as commercialised since 2002 in Sweden, can operate with ethanol blending levels of 85 %. Biodiesel use in blends below 7 % does not require engine modifications, while minor modifications on vehicle engines might be necessary when using pure biodiesel. Pure vegetable oils can also be used in blends or in pure form, in adapted engines.

The production cost of ethanol and biodiesel declined substantially over the past years, but is still higher than that of petrol and diesel. However, in Brazil, sugarcane bioethanol cost is lower than fossil fuel costs. The low cost production of sugarcane ethanol in Brazil is unlikely to be replicated in other countries due to lower yields and higher costs. The bioethanol (wheat, sugar beet) cost ranges from 55-68 €/MWh and the biodiesel cost (rapeseed) varies between 60 and 63 €/MWh (oil price 50 €/bbl) [1]. Investment costs for a wheat bioethanol plant in the EU are about 800 -1 200 €/kW ethanol [2, 3]. Investment capital costs for a biodiesel plant from vegetable oils are about 200 - 500 €/kW biodiesel [4, 5, 6, 7].

Upgraded biogas produced through anaerobic digestion from various agricultural feedstocks can be also used as transport fuel. Additional cleaning and upgrading of biogas is needed to be used in internal combustion engines. There is an important potential for biogas and/or synthetic **biomethane** from agricultural feedstock to be used in the transport sector. However, biogas is used mainly at present for heat and electricity production, only a small share being used as fuel gas for transportation and this trend is expected to continue in the future.

Second generation, lignocellulosic biofuels are expected to deliver more environmental benefits and higher feedstock flexibility than first generation biofuels, but future costs are uncertain.

Lignocellulosic biofuels can be produced from agricultural and forest residues, wood wastes, the organic part of municipal solid wastes (MSW) and energy crops such as energy grasses and short rotation forestry. This has low or no additional land requirements or impacts on food and fibre production. Relatively high energy yields (GJ/ha) can be obtained from energy crops compared to the traditional food crops used for first generation biofuels. The second generation biofuel productivity is in the order of 2 to 4 toe biofuels/ha. New varieties of energy crops might have increased yields, lower water demand and lower agrochemical requirements.

Algae could be an important feedstock for biofuels which can theoretically produce around 45 000 l of biodiesel/ha, compared to 1 500 l of biodiesel/ha from rapeseed, 4 500 l of biodiesel/ha from oil palm and 2 500 l of bioethanol/ha from maize. Algae can be produced in closed photo-bioreactors or open ponds. One option is to grow algae in open sewage ponds, where nutrients are in abundance, to treat sewage water. Algae and oil concentration is relatively low and biofuel production would require high volumes of algae to be cultivated. However, capital costs for these plants are high. Biofuel production from algae is presently at the research and development stage, focussing on evaluating the optimum strains of algae, investigating process development and oil extraction.

The processing of cellulosic feedstocks is more complex than processing sugar- and starch-based crops. Options available for lignocellulosic biofuels include biochemical enzyme hydrolysis and thermo-chemical Biomass-to-Liquid (BTL) processes. The biochemical processes involve the conversion of cellulose or hemicellulose by enzymes and other micro-organisms to bioethanol through a saccharification stage followed by fermentation. Thermo-chemical processes are based on pyrolysis or gasification to produce a wide range of lower chain hydrocarbons from the synthesis gas: synthetic diesel, synthetic biomethane, methanol or dimethyl ether.

The biochemical process and thermo-chemical processes remain unproven on the commercial scale and are under development and evaluation. Several demonstration plants are operating, under construction or planned in the US and the EU. Significant data on the performance of the different conversion routes will become available as more demonstration plants come into operation in the next years. There are currently no clear technical or economic advantages between the biochemical and thermo-chemical pathways. Both conversion routes offer a relatively low biofuel conversion efficiency of around 35 % and similar potential yields in energy terms per tonne of feedstock. Lignocellulosic ethanol production through enzyme hydrolysis is expected to produce up to 300 l ethanol/tonne of feedstock, whilst the BTL route could yield up to 200 l biodiesel/tonne of feedstock.

Integrated concepts, called bio-refineries, are considered better options for the production of a variety of bio-based products. Different pathways and a portfolio of products are currently investigated to identify the most interesting options. Market deployment is expected by 2030.

Hydrogen produced from biomass, or *third generation biofuel*, is expected to play a significant contribution in the transport sector from 2030.

Production costs of second generation biofuels are uncertain, as little data is available. Even at high oil prices, second generation biofuels will not become fully commercial nor enter the market without a significant improvement in the technology. Current estimates of costs show that second generation biofuels are 30 % (second generation bioethanol) to 70 % (BTL) more expensive than the respective production of first generation fuels in the EU [8] The current estimates show a variation between 77 and 96 €/MWh for lignocellulosic ethanol and between 57 and 98 €/MWh for BTL (JEC Study, oil price 50 €/bbl). Capital investment costs reported for lignocellulosic ethanol are of the order of 1 800 to 2 100 €/kW ethanol [9, 10, 11, 12]. Capital investment costs reported in the short term for biodiesel production through biomass gasification (Fischer-Tropsch process) are in the range of 3 000 to 4 000 €/kW biodiesel [13, 14].

Since the lignocellulosic biofuels are in a pre-commercial phase, further improvement in technology and cost reduction are expected due to the learning effect. Synthetic diesel production from thermo-chemical pathways offers lower potential for cost reduction than the ethanol via biochemical conversion pathway, as thermo-chemical pathways require mainly process integration of already established processes (gasification, pyrolysis, gas purification), where there is limited scope for further cost reduction. Given the complexity of the technical challenges and high production costs, the first commercial plants are unlikely to be deployed before 2015 or 2020 [15].

14.2 Market and industry status and potential

In 2007, biofuels account for around 1.5 % of global transport fuels or 34 Mtoe. Total world bioethanol production tripled between 2000 and 2007 to reach over 25.5 Mtoe (13.3 Mtoe in US and 7.3 Mtoe in Brazil). Biodiesel production increased by a factor of 10 from 2000 to 2007, reaching around 8.6 Mtoe or 0.2 % of total diesel demand worldwide. The EU is the main producer of biodiesel with 4.9 Mtoe of biodiesel in 2007, followed by the US with about 1.4 Mtoe.

The share of biofuel in liquid fuels consumed for road transportation in the EU accounted for only 0.2 % in 2000, but increased to 1 % in 2005, 1.8 % in 2006 and 2.7 % in 2007 and is projected to reach 10 % by 2020. Biofuel consumption continued to increase in 2007, at a rate of 44.5 %, reaching 8.1 Mtoe, of which 6.1 Mtoe is biodiesel, 1.2 Mtoe bioethanol and 0.8 Mtoe other types, such as vegetable oil. Euroserv'ER [16] estimated biofuel consumption in 2010 to be 17.5 Mtoe, reaching the overall goal of the Biofuels Directive 2003/30/EC [17]. Germany is the main leader for biofuel consumption in the EU (49 % of the EU total), followed by France (18.4 %), Spain (4.6 %), UK (4.3 %) and Austria (4.3 %). In 2007, Germany was the leader in the biofuel incorporating rate in fuels used for transport (7.3 %) followed by Austria (4.23 %) and France (3.5 %) [16].

The European Commission (EC) proposed a Road Map [18] that includes a binding overall EU 20 % RES target by 2020 and a 10 % minimum binding target for biofuels for each EU Member State. The Directive 2009/28/EC [19] on the promotion of the use of energy from renewable sources set a mandatory target of 10 % share of energy from renewable sources in the final consumption of energy in transport in each Member State by 2020. This would require a consumption of 35 Mtoe of biofuel, according to the EU-27 energy baseline scenario to 2030 [20]. The biofuel deployment expected according to the baseline scenario, as derived from the EU's "Energy and Transport Trends 2007 Business as usual scenario, shows a biofuel share of 7.4% in 2020 and 9.5 % in 2030 [20]. Additional deployment to reach the 10% target by 2020 can be assumed as SET-Plan leverage effect. According to the Biofuels Research Advisory Council [21], up to one quarter of the EU's transport fuel needs could be met by biofuels in 2030.

14.3 Barriers

The cost competitiveness of biofuels compared to conventional fossil fuels remains a key barrier for biofuels use in the transport sector. There are also a number of concerns about first generation biofuels related to their impact on the environment, biodiversity and water resources, land use changes, real GHG emission reductions and cost of CO₂ avoided emissions. There are concerns about the additional negative effects of intensified agricultural practices aiming at higher yields or to the extension of agriculture on areas that are not presently cultivated, leading to significant land use change and one-time release of high emissions of CO₂. This could offset climate change benefits or other benefits from the use of biofuels due to a huge carbon debt and very long payback time. Another concern is the GHG emissions from indirect land use changes. There is a large uncertainty related to the soil carbon content changes due to the land use change and how to link Indirect Land Use Changes (ILUC) to biofuels production.

The allocation of biomass resources between electricity, heat and transport fuel production, and the competition for biomass resources with non-energy sectors are critical issues. There are also concerns that biofuels produced from food crops affects food security and availability and contributes to food shortage and increased food and feed prices by displacing land that would otherwise be used for food production.

The main barriers for lignocellulosic biofuels are technology improvements for the biochemical and thermo-chemical routes. Technology improvements are needed for the thermo-chemical route, improvement of pyrolysis and gasification processes, efficiency improvement, process integration and cost reduction. For the biochemical pathway, there is a need to improve the pre-treatment stage, improve the efficiency of enzymes and reduce their cost, to improve overall process integration and achieve cost reduction. There is a need to enlarge the feedstock base, to process new feedstocks (such as new lignocellulosic feedstock and aquatic biomass) and improve productivity to reduce competition with food, feed or fiber markets. Where lignocellulosic feedstock comes from energy crops grown on arable land, several concerns still remain about the competition for land, although high energy yields (GJ/ha) are likely to be higher. The indirect impact of diverting waste/residue feedstock into biofuels production, when these materials have other uses, e.g. tallow, must also be considered. This diversion might offer limited GHG savings or even an increase in GHG emissions, because the demand for the displaced feedstock still needs to be met from other sources [22].

Biofuel certification is expected to reduce the concerns related to the sustainability of biofuels. However, biofuel certification faces large difficulties due to the different types of feedstock and high number of conversion pathways. A crucial question is to what extent would biofuels lead to additional land use change and how can these be addressed. The displacement effect is addressed in the Directive 2009/28/EC [19] by obligatory reporting from Member States and Commission on the impact of EU biofuel policy on the availability of food, commodity price and land use changes associated with the increased use of biomass.

Significant uncertainty is related to the GHG emission savings of biofuels. The varying assumptions and methodologies used for determining GHG emissions through LCA yield very different results, even for the same crop from the same country, leading to concerns about the validity of GHG calculations. Additional uncertainties have been raised about the GHG savings if direct and indirect land use changes are considered. Indirect effects are difficult to monitor, measure and control and no assessment methodology is presently available based on science to estimate the GHG emissions from Indirect Land Use Change (ILUC).

14.4 Needs

A strong coordination and more focused RD&D efforts at the EU and national levels is essential to improve conversion processes and advance new technologies, including system integration to overcome current technical and cost barriers. More RD&D efforts are needed on biomass supply logistics and feedstock production, for the improvement of energy crop yields and for developing energy crops that are less competitive with food crops, such as jatropha, algae, etc.

The development and monitoring of several demonstration plants for second generation biofuels on a relevant industrial scale are crucial for process development and scaling-up of the technology and to acquire accurate comparative data to validate technical and economical performance. However, they are capital intensive and their operation is costly. Government grants are needed for demonstration plants to encourage investors to take the risk of developing commercial scale conversion plants.

A long term and coherent policy framework and innovative financing mechanisms need to be put in place before the technology reaches commercial maturity. An overall harmonisation of incentives and

regulations is required across the EU to avoid market distortion and promote competition. A strong coordination between biomass suppliers, car manufacturers and the fuel industry is essential to balance the evolution of the EU vehicle fleet and the infrastructure against higher penetration of biofuels. This should be backed-up with standards and harmonised administrative procedure across the EU.

The set-up of a sustainability certification scheme is of prime importance to ensure biofuels production in a sustainable condition to avoid direct and indirect land use changes and negative impact on food security and food availability. The definition of adequate biofuels/bioenergy sustainability standards and implementation mechanisms and verification procedures will be crucial for the success of the sustainability certification.

The development of resource mapping and Life Cycle Analysis tools, based on a standardised methodology and assumptions, widely accepted for GHG emissions assessment, are needed. Methods must be developed to evaluate Direct and Indirect Land Use Changes. The impact of indirect land-use change on GHG emissions must be assessed and a methodology for the evaluation of emissions from carbon stock changes caused by indirect land-use changes is also necessary. The impact of biofuel targets on the availability of food products and changes in commodity prices and land use associated with the use of biomass for energy must also be evaluated.

14.5 Synergies with other sectors

There are synergies between the Common Agricultural Policy (CAP), Forestry policies, rural development, industrial and trade policies in the EU. There is a need for a harmonisation and increased coherence between the Common Agricultural Policy, and Energy and Climate Change policies. There is competition for the feedstock with food-crop production. Competition is also expected between biomass use for heat and electricity and for lignocellulosic biofuels and with other sectors, such as the pulp, paper and wood processing industry. In the long run, synergies with hydrogen are foreseen in the advent of fuel cells and the large scale deployment of hydrogen in the energy sector.

Coordination is of a prime importance with the non-energy based biomass industry, but also between biomass use for heat and electricity and for biofuels. There is a need for a harmonised and coherent policy framework as underlined in the EU Biomass Action Plan and in the EU Strategy for Biofuels. A cross-sectoral coordination between agriculture, forestry, pulp and paper and wood processing industry is required.

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15 FUEL CELLS AND HYDROGEN

15.1 Technological state of the art and anticipated developments

During the last decade, major R&D programmes for fuel cell and hydrogen applications have been performed worldwide in which remarkable performance improvements have been achieved. Given this rapid pace of innovation and provided that the necessary accompanying measures to bridge the transition to self-sustaining hydrogen and fuel cell commercial activities are put in place, the next few decades are expected to see the development of hydrogen and fuel cell systems meeting a vast range of consumer and industrial needs that equal or surpass the performance of present energy technologies, thereby contributing to economic prosperity and environmental sustainability, and diminishing the world's reliance on fossil fuels and CO₂ emissions.

Whereas the 2007 issue of the Technology Map contained two subchapters related respectively to hydrogen and to fuel cell technologies, the version here follows the structure of the Multi-Annual Implementation Plan (MAIP) [1] of the Joint Technology Initiative for Fuel Cells and Hydrogen (FCH-JTI). In establishing the MAIP, working groups comprising of representatives of the Industry and Research Groupings and of the European Commission have assessed the outcomes of the Implementation Plan of the Hydrogen and Fuel Cell Technology Platform [2] and of the road mapping studies, such as HyWays [3] (for transport mainly) and Roads2HyCom [4]. This led to a timeline for the market introduction of fuel cell and hydrogen technologies in a number of application areas, which lies at the basis of the deployment figures included in section 15.2. From there, and considering the budgetary constraints, high level objectives and targets for four application areas and cross-cutting activities during the initial stages needed for the market introduction were derived. The MAIP cost targets refer to a 2015 horizon and are based on a specified quantitative deployment of the considered technology.

Transport and refuelling infrastructure: The main technological parameters in this Application Area are the performance and durability of polymer electrolyte membrane fuel cell (PEMFC) systems and the volumetric and gravimetric density of on-board hydrogen storage. Technological progress and associated cost reduction are both critical for the sustained market potential of fuel cell vehicles. The power density of the fuel cell stack without storage has been steadily improving, now reaching about 600 W/l. Power density, including the storage subsystem, has exceeded 160 W/l (US Department of Energy (DoE) 2010 target: 220 W/l). Concerning durability, the HyFLEET:CUTE [5] demonstration project reports more than 4 000h operation for some stacks in bus application, compared to the 2015 MAIP system target of 5 000h for passenger cars. Long-term laboratory tests have indicated the occurrence of new failure modes which impair long-term performance. Further investigation of degradation mechanisms and of related diagnostic tools is needed. Also the effects of hydrogen and air impurities on performance and durability require further investigation. Air management is still a challenge because compressor technologies are not adapted to automotive fuel cell applications. Thermal and water management remain an issue because the small difference between operating and ambient temperatures necessitates large heat exchangers. Current research addresses the development of membranes able to operate at low humidity in order to eliminate the need for complicated water management equipment. It also targets reduction of catalyst loading of expensive Platinum Group Metals (PGM) and higher operating temperatures to allow the use of less pure hydrogen and reduce the need for humidification and cooling system requirements.

The on-board hydrogen storage density is the determining factor for the vehicle driving range. The energy density of liquid and of 70 MPa high-pressure hydrogen storage allows for a range of 500 km, but these storage technologies still impose a volume penalty. In view of the lack of progress in solid-state H₂ storage technologies and the energy losses in liquid cryogenic storage, high-pressure gas

storage is currently the preferred option. Besides actions to further reduce costs, research is therefore targeted at reaching an overall system density for on-board H₂ storage of 9 %wt of H₂ (the state of the art of gaseous H₂ storage (70 MPa) is 4 %wt; cryocompressed H₂ 5.5 %wt). With the balance of plant (BoP) constituting at least half of the weight of the system, this translates into 5.5% H₂ weight percent in the storage.

A hydrogen consumption of 0.27 kWh/km (about 1MJ/km), equivalent to 3 litres of petrol per 100km, is expected for hydrogen fuel cell vehicles (HFCV) by 2015, nearly 40% less than the fuel consumption of an advanced internal combustion engine for a similar vehicle size. For hydrogen internal combustion engines (HICE), the corresponding figure is 0.46 kWh/km.

The MAIP targets an overall system cost for HFCV of 100 €/kW in 2015. US figures estimate a fully learned out cost for the fuel cell drive train (consisting of the fuel cell system, hybrid battery, motor and auxiliaries) of 50 \$/kW, with the fuel cell system cost constituting 30 \$/kW [6]. Around half of these costs are attributable to the stack and the remaining half to the balance of plant. For high-volume production (500,000 units per year), DoE indicates a cost of 73 \$/kW, based on recent successful 5-fold reduction of Pt loading, a major cost determining factor. As stack costs reduce, BoP components become responsible for a larger percentage of the overall costs. The cost target for hydrogen internal combustion vehicles is 18 €/kW. Cost targets in the EU are less stringent than those in the US because of the lower US petrol tax, which imposes lower cost targets for new technologies to become competitive. In the EU, when de-taxation is applied to compensate for reduced externalities, cost targets can be higher and still be competitive with conventional technologies.

Cost figures for on-board H₂ storage have hardly decreased in recent years, with 18 \$/kWh reached for 70 MPa storage. Learned out hydrogen storage cost is currently estimated at 10 \$/kWh which has caused DoE to critically review the 2 \$/kWh target for 2015 [7]. For liquid storage, an ultimate goal of 15 \$/kWh is claimed. Targets in Hyways [3] are 10 €/kWh for 2020 and 5 €/kWh in 2030. A cost of 8 €/kWh for hydrogen storage translates into a total tank cost of about 1200 € for a typical four-passenger HFCV.

To date, only a few hundred HFCVs have been produced, with none of the advantages of mass production. Costs in high-volume manufacturing can be estimated only roughly, because major subsystems are still in the development stage. Current best estimates for 2020 are 23-26 k€ for the standard reference HFCV with a 80kW fuel cell stack [3].

The FCH-JTI targets a cost of hydrogen delivered at a refuelling station of less than 5 €/kg (0.15 €/kWh) in 2015. US costs projected for 2030 for a 1.5 ton H₂/day fuelling station delivering H₂ produced from steam reforming of natural gas at 34 MPa range between 2.5-3.0 \$/kg. Electrolyser stations can only compete with this at industrial electricity costs between 0.02-0.03 \$/kWh [7, 8, 9].

For the aforementioned consumption of 0.27 kWh/km, equivalent to 8 g/km, a production cost of 5 €/kg translates into a cost of 0.04 €/km. For 2030, these costs are projected to range from 0.018-0.024 €/km for the majority of hydrogen production pathways, similar to those for petrol and diesel ranging from 0.020-0.022 €/km (without taxes).

Today's investment cost for a refuelling station with on-site production is about 1 000 €/kWh₂, projected to decrease to 460-550 €/kWh₂ in 2030, depending on the size. The total cumulative investments for infrastructure build-up amount to about EUR 60 billion for the period up to 2030 [3]. The under-utilisation of the infrastructure during the early stages will cause higher costs/km for the vehicles.

Hydrogen production and distribution: Several processes and feedstocks will be used to produce hydrogen either in centralised (large scale) or decentralised (small scale, distributed) plants. These processes have different degrees of maturity, production capacity and sustainability. In the short and mid-term, the more mature technologies will have to meet the demand. In the longer term, fully sustainable hydrogen production and supply pathways need to be further developed and tested. The FCH-JTI aims at enabling the supply of 10-20% of the anticipated hydrogen energy demand in the period up to 2015 (expected to come mainly from transport and early market applications) with CO₂ lean or CO₂ free hydrogen.

The hydrogen distribution system from the production to the consumption site depends on the hydrogen production method (centralised or not), the production volume and the distance to the consumer sites.

Large scale (centralised)

Steam reforming of natural gas is a mature technology for large scale hydrogen production in the range 50-200 MWH₂. Energy efficiencies are of the order 70-80%. Heavy oil and coal gasification is a second main pathway, with energy efficiencies 50-65%. Large scale fossil fuel based hydrogen production requires decarbonisation of the production stream, resulting in an expected efficiency drop of 6-8 percentage points, with a 20 to 30% production cost increase. Market entry of carbon capture and storage (CCS) technologies is expected around 2020. The greatest challenge to large scale coal-based hydrogen production does not lie with the technology itself, but with demonstrating the capacity and safety of long-term geological CO₂ storage. Other areas that warrant development before commercial implementation include new gasification reactor designs, improved gas separation and purification technologies. Co-producing power and hydrogen at a large coal gasification facility potentially offers an attractive low-cost method for making hydrogen. The concept has not yet been demonstrated at a large scale although all processing modules are commercially available.

In theory, also biomass can be gasified on a large scale, with expected efficiencies of the order of 45-65%. As biomass is produced in relatively small quantities per surface area, a biomass plant is likely to be much smaller than a coal plant. A different gasification technology could therefore prove more suitable for making hydrogen from biomass. Small-scale (100-300 tons/day biomass) gasification test plants use low-pressure, indirectly heated air for gasification, thereby eliminating an expensive air separation unit for oxygen feed. Although individual parts of the biomass gasification process have been demonstrated, the entire process has not. Gas cleanup technologies that can adequately remove contaminants and tar also still need to be demonstrated.

Although on an overall chain basis, large scale electrolysis using fossil or nuclear generated electricity is not efficient (round-trip efficiency 35-40%), it is a key technology to enable high penetration of renewable electricity, particularly in the transport sector.

Beyond 2030, high temperature thermo-chemical and electrolytic water splitting processes using concentrated solar thermal and nuclear energy are being investigated for large scale hydrogen production. The efficiencies of the most investigated, thermo-chemical cycles are 40-50%. To achieve acceptable efficiencies at lower operating temperatures, solar-assisted catalytic water splitting is investigated, with subsequent regeneration of the catalyst. Research is also under way on low-temperature, low-cost sustainable biohydrogen production processes and photo-electrochemical processes for direct hydrogen production. The latter, based on direct conversion of solar radiation, have the drawback that an explosive hydrogen-oxygen mixture is produced, requiring an additional separation stage.

Centralised hydrogen production necessitates the development of a hydrogen transmission and distribution infrastructure as well as facilities for large and medium scale storage. Whereas the pipeline transmission system offers a buffering storage capacity, depleted gas fields, aquifers and caverns may serve as large scale underground storage. Medium scale storage uses buried liquefied hydrogen tanks and compressed hydrogen tanks above-ground.

Small scale (distributed)

On-site production units are expected to play an important role until hydrogen demand in the energy and transport sector reaches a level that justifies investment in a dedicated hydrogen centralised infrastructure. For small scale distributed generation, it is not feasible to capture the CO₂ because of the large number and small size of the production sites.

Natural gas steam and auto-thermal reforming processes of a few MWH₂ are still at a demonstration/commercialisation phase. Energy efficiencies are in the range 45-68%. In practical applications, such as the HyFLEET:CUTE demonstration project [5], efficiencies are lower because of non-continuous operation and non-optimal matching of generation and demand. Electrolysis is a common way to produce small amounts of hydrogen. Water electrolysis will play a role in the early to mid stages of the hydrogen transition because of the advanced stage of technology development, the widespread availability of electricity and the relatively simple operation of an electrolyser. Scaling up an electrolyser to the required 1,500 kg of hydrogen per day for a refuelling station has been demonstrated. The best practice figure for efficiency (excluding auxiliaries) is close to 80-85%. Larger units are usually less efficient at 75-80%. Whereas alkaline systems have track records for lifetime, reliability and lower capital costs, membrane electrolysis offers the advantage of higher production rates and efficiencies. Both technologies have demonstrated high-pressure generation capability. Efficiencies can further be improved by using solid polymer electrolytes and high temperature (700-900°C) supercritical water vapour electrolysis.

Small scale biogas production through anaerobic digestion is a mature technology. Its conversion into hydrogen is largely based on similar technologies used to convert natural gas. Biochemical fermentation either in an anaerobic or in a phototrophic environment is under experimental development.

The cost of hydrogen produced at a central plant and delivered to consumers is very sensitive, not only to the feedstock cost and conversion technology, but also to the plant size, the purity level and the method and distance for hydrogen delivery. In a fully developed hydrogen economy, delivery and dispensing of hydrogen will consume significant energy and could cost as much as its production [10].

Capital investment costs in the near term for centralised production of the purity required for use in PEMFC are in the range of 300-400 €/kWH₂ for natural gas steam reforming, 900-1 000 €/kWH₂ for coal gasification (without CCS), and 900-1 500 €/kWH₂ for biomass gasification. As investment costs are inversely proportional to plant size, they are higher for decentralised than for centralised production. For small scale reforming, they range from 700-2 000 €/kWH₂ for capacities from 600 kWH₂ - 6 MWH₂. Capital cost projections for 2030 fall in the range 300-700 €/kWH₂. For electrolysis, costs are of the order of 800-1 500 €/kWH₂. Capital investment for pressurised systems is of the order of 900-2 200 €/kWH₂ for capacities from a few 100 kW to a few MW, with prospects of 500-700 €/kWH₂ [3]. The DoE programme has recently developed a concept for a low-cost alkaline electrolyser with the potential to meet the 2012 target of 400 \$/kW [7].

Current plant-gate production costs (capital + operation) are quoted to range between 3-4 \$/kg at low volume and 2-3 \$/kg H₂ at high volume. In 2030, natural gas steam reforming production costs are projected at 1.3 \$/kg for large and between 1.7-2.6 \$/kg for decentralised generation on at refuelling

station scale. For hydrogen from a 430 MWH₂ coal gasification plant, they are estimated at 1.50 \$/kg, excluding costs for CCS. Recent advances in biomass gasification indicate that the cost could approach 3 \$/kg with continued technology progress and demonstration of the feasibility of large-volume biomass production and transportation to central gasification facilities [9]. Instead of gasification of biomass, hydrogen could also be produced by gasifying one of the many biomass conversion products, such as ethanol. The conversion technologies are known, but the cost of production greatly exceeds the aforementioned figures and depends highly on the feedstock cost. The Hyways project indicates that for an oil price of 50 €/bbl hydrogen production costs of 4 €/kg and of 3 €/kg can be achieved in 2020 and in 2030 respectively [3].

Stationary power generation & combined heat & power (CHP): Stationary fuel cells are compact power plants that use hydrogen or hydrogen-rich fuels to generate electricity or electricity and heat (CHP) for residential (1-70 kWe) and industrial (>100 kWe) applications. In high-temperature fuel cells (MCFC, SOFC), natural gas and biofuels are expected to remain the dominant feedstock up to 2030. In selected applications, biogas, sewage gas and (bio)methanol are used.

Stationary fuel cells are attractive because of high efficiencies, low noise and vibration and potentially low O&M requirements, hence less down-time than other power generation devices such as diesel generators and gas engines. Their modularity allows tailoring their capacity to the power and heat requirements. For industrial applications, the FCH-JTI targets electrical efficiencies >45% for power-only units and a combined efficiency >80% for CHP units, coupled with lower emissions and use of multiple fuels, and lifetime requirements (durability) of 40,000 hours for cell and stack.

MCFC are currently the most mature technology for applications above 100 kWe, with SOFC in the demonstration stage. Load-independent electrical efficiency of the order of 45% and up to 40% thermal efficiency has been achieved with cumulative experience over tens of years. For lower power ranges for residential applications, SOFC as well as PEMFC are being demonstrated. PEMFC are also ideally suited for energy recovery from high purity excess hydrogen, as for example from chlorine production. A 50kWe plant has been successfully running for over 10,000 h and a 1 MW plant is expected to be delivered in 2010 [11].

Current R&D for MCFC and SOFC aims at improving durability and focuses on understanding degradation and lifetime fundamentals related to materials under typical operating environments for all power ranges. At the system level, R&D pursues optimised interaction with supply and demand interfaces.

The capital investment for stationary fuel cell applications depends on the power range. For more than 100 kWe, it ranges between 6 000 and 10 000 €/kW, with MCFC at the lower cost range. The FCH-JTI targets a cost of 1 500-2 500 €/kW for industrial units and 4 000-5 000 €/kW for micro-CHP. It is noted that at present, 2/3 of costs stem from balance of plant components. For road APU, DoE targets 750 \$/kW by 2011 [6].

Early markets: Although fuel cell and hydrogen technologies are still some distance away from full commercialisation, the industry has identified early market applications which are currently targeted with low volume production units. These markets are driven by a demand for applications that exploit one or more advantages of the technology (high efficiency and reduced energy consumption, low noise, low heat signature, absence of exhaust fumes, reduction of space requirements and weight, longer runtime, ...) and that can already be implemented using current technology. Current early markets include material handling vehicles, more than 5 original equipment manufacturers (OEMs), back-up and UPS stationary power (>10 OEMs), portable applications (>40 OEMs), marine transport (> 2 OEMs), vehicle auxiliary power units (>5 OEMs), captive fleets (>5 OEMs) and

scooters/wheelchairs (>10 OEMs). The majority of these early market applications compete with pure-battery electric counterparts.

15.2 Market and industry status and potential

Fuel cells and hydrogen are medium and long-term energy technology options whose contribution to meet the 2020 EU targets on greenhouse gas emissions, renewable energy and energy efficiency will be limited. However, they are expected to play an important role in achieving the EU vision of reducing greenhouse gas emissions by 60-80% by 2050. Moreover, modelling has demonstrated that large scale deployment of hydrogen technologies increases the use of domestic energy resources, and hence contributes to enhancing EU security of energy supply [3]. Market penetration of fuel cells and hydrogen is envisaged to develop as follows: micro and portable fuel cells will increase sharply in the very near future, followed by increasing numbers of residential heat and power systems, and then light-duty vehicles powered by PEM fuel cells.

Hydrogen is at present used extensively for the production of ammonia, methanol, petrol and heating oil. It is also used to make fertilisers, glass, refined metals, vitamins, cosmetics, semiconductor circuits, soaps, lubricants, cleaners, and foods such as margarine and peanut butter. Current hydrogen production worldwide is around 60 Mt/year, in energy terms equivalent to 4.3% of the yearly global oil production, sufficient to supply the hydrogen for half of the estimated number of 600 million cars worldwide [10].

There are many types of fuel cells with differences primarily based on membrane materials and electrolytes. Each fuel cell type therefore has its own operating characteristics and different application opportunities. The largest markets for fuel cells today are in stationary power, portable power, auxiliary power units and forklifts. The fuel cell industry to date has produced 800 large stationary fuel cell units, well over 3 000 small stationary units, 600 light duty fuel cell vehicles, over 60 fuel cell buses and more than 600 small mobile applications globally. The global use of hydrogen fuel cell systems grew at an estimated annual rate of 59 percent from 2005 to 2007 [10]. About 18 000 fuel cells were shipped in 2008, a more than 50% increase over 2007 [7].

The global fuel cell industry is expected to generate more than \$18.6 billion in 2013, with sales coming from three main market applications: automotive, stationary and portables. Projected sales could generate up to \$35 billion if market conditions improved for automotive fuel cells [12].

The percentage of fuel cell units manufactured and sold by technology type has remained fairly steady in recent years. Overall, the market continues to be dominated by PEMFC, the most flexible and market-adaptable fuel cell technology. However, other types of fuel cells are slowly gaining acceptance, creating a more dynamic and robust industry. At the larger end of the power range, MCFCs are still dominant, but the potential for SOFC increases.

Transport and refuelling infrastructure: The main markets for hydrogen in the transport sector are passenger cars, light duty vehicles, city transport (busses, rail cars) and utility vehicles. Heavy duty transport (trucks) and long distance coaches are expected to switch to alternative fuels, e.g. biofuels, because of their more severe restrictions concerning weight and operating ranges. The same applies for shipping and aviation.

At present, demonstration of vehicles powered by hydrogen fuel cells or internal combustion engines is taking place around the world. In late 2008, this covered 179 fuel cell vehicle, 50 hydrogen ICE and 75 hydrogen bus demonstrations, supported by 79 fuelling stations [10]. Recently a "real-world" driving range of more than 800 km has been demonstrated for passenger HFCVs with 70 MPa

compressed hydrogen storage. More than 80 000 hydrogen vehicle refuellings have occurred globally to date and a 3 min filling time for 4.5 kg H₂ has been demonstrated for a 70 MPa fuelling station.

In the EU, several innovative re-fuelling options are currently being demonstrated. They include on- and off-site production and use of bi-product hydrogen distributed by pipeline. It is noted that an integrated approach is pursued that includes re-fuelling and end-use. The hydrogen bus projects CUTE and HyFLEET:CUTE have seen operation in public service of 47 buses (33 fuel cell and 14 internal combustion engine). A total of 10 hydrogen filling stations, of which 6 with on-site production facilities, are being used. Over 8.5 million passengers have been transported over a total of 2.5 million km. The hydrogen supply technology portfolio comprises on-site electrolysers and on-site NG/LPG reformer as well as external hydrogen delivery pathways [5]. In the fuel cell car demonstration project ZeroRegio, different supply chains are being tested: industrial by-product source and delivery from a central production facility with an on-site reformer capacity. Considerable experience has been gained on pipeline distribution and high pressure (70 MPa) fast refuelling [13]. The HyChain partnership has researched high pressure cartridge refuelling, using 2 litre cartridges and 20 litre cylinders and mobile quick filling stations for powering more than 50 special purpose vehicles, including small utility cars and minibuses, wheelchairs, scooters and cargo-bikes [14]. The fleets are based on similar modular technology platforms to reach a large enough volume of vehicles to reduce costs and overcome major barriers. In September 2009, leading vehicle manufacturers declared to pursue the development and commercialisation of fuel cell vehicles in Germany, anticipating the deployment of several hundred thousand units from 2015 onwards.

The hydrogen internal combustion engine is considered as a transitional technology because of the inherently lower efficiency than can be achieved with fuel cells. If the recent technological progress in size and weight reduction, cold-weather operation, and durability improvements for fuel cells are continued over the next few years, commercialisation may be expected by 2020. The costs of early fuel cells are likely to be higher than the targets in the different programmes, but they will drop with continued development and large-volume manufacturing. By 2030, hydrogen vehicles may constitute a few percent of the EU passenger car fleet and up to 70% by 2050. Due to their much longer lifetimes, it is difficult to envisage hydrogen used for propulsion in airplanes and ocean-going ships in the 2050 time horizon. However, current interest in shifting freight transport from roads to in-land waterways combined with stated objectives for improving environmental quality may be a driver for use of hydrogen in in-land vessels, as well as in leisure craft. Within the ZEMSHIPS (Zero Emission Ships) project a fuel cell passenger ship has been put into service. It is fuelled by liquefied hydrogen delivered by road tankers and filled into a super-insulated storage tank [15]. The aircraft manufacturer Airbus has recently announced that it will equip its aircrafts with a multi-functional fuel cell auxiliary power unit (APU) aimed at generation of on-board power as a step in the evolution towards more electric aircraft. Airbus has also been investigating how in the longer term hydrogen fuel cells can provide propulsion power for aircraft.

The development of the required hydrogen infrastructure is envisaged to take place in a complex manner over substantially more than a decade as the population of fuel cell vehicles grows. In the early phase, fuelling stations will cover the needs of early user centres in densely populated areas and in interlinking corridors. Hydrogen will initially come from existing centralised production facilities and will be distributed by tube trailer or liquid carrier. These supplies will increasingly be supplemented by distributed generation in fuelling stations, using steam reforming of widely distributed natural gas or by water electrolysis powered by the electric grid, preferentially during off-peak periods. Recent experience from the HyFLEET:CUTE demonstration project seems to indicate that small-scale reforming based production suffers from too large a footprint for urban stations and from complexity in operation, combined with a non-optimum efficiency. This may extend the period of trucked-in hydrogen. Local production methods will be used until fuel demand in populated areas is sufficient to

justify hydrogen distribution by pipeline from centralised sources and produced in several ways, whereas remote areas are likely to continue to be supplied by the early-transition methods. Upon mass rollout of hydrogen, the refuelling infrastructure will reach the same dimensions as today's petrol/diesel network, with large stations, high usage and wide geographic coverage. In September 2009, leading German industrial companies agreed upon a build-up plan for a nationwide infrastructure, which is expected to result in a significant expansion of a hydrogen fuelling station network by the end of 2011.

Hydrogen production and distribution: The current global hydrogen infrastructure includes 3 000 km of hydrogen pipeline primarily dedicated to hydrogen use for industrial activities. This represents about 0.23% of the existing pipeline infrastructure for natural gas [10]. On an energy-equivalent basis, hydrogen is more expensive to transport and distribute than other energy carriers, hence the optimal distribution system for centrally produced hydrogen will consist of smaller-sized plants located closer to population centres, with a limited number of long-distance pipelines.

The mix of energies used for hydrogen production will depend on political targets and framework conditions, regionally available energy sources as well as achievements in technological development. By 2050, hydrogen should be produced through carbon-free or carbon-lean processes: coal gasification power plants with CCS will deliver large quantities of hydrogen and solar and nuclear heat will be used at large scale. Novel methods (such as biological processes and photochemical water splitting) will produce hydrogen from solar energy at low temperatures. Finally, hydrogen will be used as an energy buffer to balance the production and demand cycles of intermittent power sources, integrating large volumes of renewable energy in the energy system.

Stationary power generation & combined heat & power (CHP): In stationary applications, fuel cells are used where their high part-load electrical efficiency, high combined power and heat efficiency and their load-following ability provides a competitive edge. Stationary applications range from small-scale residential (a few kW) to large-scale industrial (some 100 kW). Small-scale applications include convenience stores, laundromats, spas, pools, car washes, luxury homes, etc. Other small scale, high volume application areas are remote, off-grid mobile telephone transmitter stations and back-up systems in hospitals and data centres, military deployments, ski resorts, etc., where reliability is of prime concern. The use of fuel cells in these applications shows considerable advantages in terms of run time, e.g. for data centres, downtime per year is less than 3 seconds compared previously with minutes, durability, far lower replacement rate than batteries, and reduced maintenance, which all lead to reduced operating costs.

The use of hydrogen in residential and commercial CHP is not as obvious as for light-duty transport. Compared to the direct use of electricity or the direct production of electricity from hydrocarbons, the production of hydrogen for subsequent power generation introduces extra energy losses which are difficult to compensate, even if the heat released during the production of electricity at the end user is used efficiently. The penetration of hydrogen as feedstock for PEMFC in the residential and tertiary sector is therefore expected to be limited to remote areas and specific niches where a hydrogen infrastructure is already present. In the industrial sector, PEMFC are only expected where pure hydrogen is available in sufficient quantity at low-cost, e.g. vented by-product hydrogen. In the EU, an estimated 2-3 Gm³ is vented, corresponding to 400 MWh [16].

At present, hundreds of smaller systems, LTPEM, HTPEM, SOFC, fuelled by hydrogen or natural gas, are operating in test situations in private homes (primarily in Germany [17], Japan [18] and Denmark [19]), with tens of thousands of residential units scheduled for delivery between 2009 and 2014, leading to full commercialisation in the near future.

SOFC, as well as future HT-PEMFC, have a large potential as auxiliary power units (APU) in heavy duty transport to power on-board equipment during resting, e.g. radio, phone, television, computer, freezer, microwave, air conditioning, cab ventilation, etc. The APU replaces the idling diesel engine, leading to reduced emissions and energy savings of more than 50%, resulting in annual cost savings of 5 000 \$ per truck. The EU market size is estimated at 100 000 units. APUs based on on-board (integrated) reforming are being investigated for application in ships and aircraft, where also the water produced can be used.

In the industrial sector, efficiency under base-load operation is the prime criterion. Commercialisation of large capacity SOFC is expected in the next couple of years, whereas MCFC are currently operating in co-generation and tri-generation mode in the power range of a few hundred kW [17].

The MAIP targets about 100 MW installed electric capacity in 2015. By 2020, 8 to 16 GW_e would be produced by CHP by fuel cells mostly running on hydrocarbon fuels, with annual sales of the order of 2 to 4 GW_e. By 2050, CHP and micro-CHP will become increasingly important as smart grids integrate a large number of distributed power generation units in "virtual plants". Ultimately, stationary fuel cells are expected to become the reference technology for on-demand power generation in the residential and industrial sectors.

Early markets: Fuel cells to power small portable and portable electronic devices are already offered on a commercial basis to customers. At present this market is dominated by direct methanol fuel cells (DMFC), but PEMFC are steadily gaining ground. This sector is very much dominated by Japan and the US. It is expected that profitable products in back-up and UPS stationary power, in material handling vehicles (particularly for in-door use) and in scooters/motorbikes will reach the market between 2010 and 2015, with estimated up-scaling to mass production between 2015 and 2020. Estimates for hydrogen fuel cell powered forklifts in the European market amount to 25 000 new units by 2015, representing a 500 M€ H₂ market [20], whereas the market for mobile telephone transmitters and stations exceeds 1 000 000 units in the EU [16]. A particular niche is defence applications: due to their multi-fuel capability, low noise and heat signature, certain types of fuel cells are seen as strategically important defence technologies. Fuel cells are used for power and water generation on submarines, for soldier portable power and are being tested in remote-controlled aircraft. These are important early markets by value and the emergence of dual use civilian/defence markets will help increase volumes and drive market penetration.

Despite their limited commercial contribution to critical mass markets, such as automotive, early markets are recognised to have a strong positive effect on the maturing process of the technologies: they serve as stepping stones towards commercial roll-out in large volume applications by accelerating the learning among manufacturers, developers, financiers, authorities and the general public. They build a manufacturing and supplier base, create an initial revenue stream and new employment and allow the timely build-up of regulations, codes and standards (RCS) framework.

15.3 Barriers

Hydrogen and fuel cell technologies are disruptive technologies that, by their nature, require changes in all elements of the energy system. In playing a part in the necessary EU energy transition, they face technological, economical, institutional and societal barriers. In order not to disturb the existing energy system, they have to be phased-in gradually and earn their place in applications where they have a clear potential to surpass existing, as well as less disruptive, new technologies in terms of overall performance and/or lifecycle costs. In this respect, hydrogen has to compete with other energy carriers, electricity and biofuels, for its production from primary energy sources - increasingly renewable ones. Fuel cells, particularly for automotive applications, face increasing competition from other zero-emission technologies (HEV, PHEV). The technological barriers that hydrogen and fuel cell

technologies face are performance and durability of fuel cells, efficiency of large volume carbon-free hydrogen production and storage safety of captured CO₂, energy density of on-board storage and systems integration. The major economical obstacles are cost and lack of cash-flow for making up-front investments during the first phase of deployment (particularly for SMEs). The main institutional hurdle is the inappropriateness of existing policy and regulatory frameworks to allow the uptake and optimised gradual phase-in of disruptive technologies into the energy system and to enable bridging the "valley of death" between demonstration and large scale deployment. Societal barriers include public acceptance, safety perception and the insufficient coverage of fuel cell and hydrogen technologies in education curricula. People may also have to adapt to vehicles with less range capability than today's diesel ones, though achievable ranges do compare with those of higher powered petrol cars.

15.4 Needs

Addressing the barriers requires action on several fronts. More and better targeted R&D will contribute to improved performance and enable part of the necessary cost reduction. These activities, covering long-term and break-through oriented research, technological development and demonstrations are covered under the four Application Areas of the MAIP, but are not sufficient. Additionally, continuous monitoring of technology and cost improvements is needed to enhance investors' confidence and to design specific support schemes tailored to the elements of different hydrogen and fuel cell chains. Socio-economic modelling is required to optimise the entry of hydrogen and fuel cell technologies in the energy system at the right place and time and hence to guide infrastructure transition planning.

Policy measures that value societal benefits of disruptive hydrogen and fuel cell technologies, such as reduced CO₂ emissions, enhanced energy security through diversification, improved air quality, reduced noise, etc., must be put in place to ensure a level playing field with competing technologies and to facilitate and accelerate the transition. As market forces are insufficient for full-scale penetration of fuel cell and hydrogen technologies, a technology-push approach aimed at triggering early adoption and promoting market development is required. Such an approach should be based on a longer term perspective with a stable supporting framework of policies and incentives that target both technologies and public ("green" public procurement) and private market actors. This framework has to be substantial, durable, and should gradually be phased out over time with continued technology progress and deployment.

Appropriate harmonised international standards and regulations are needed to ensure safety, compatibility and interchangeability of technologies and systems, and fair competition in a global market. Equally important is the support to education, learning and the diffusion of the knowledge and technology. A prerequisite for the latter is the placement of an appropriate IPR protection framework, of particularly essence to SMEs, as a means of creating a favourable innovation environment and giving a competitive edge in the trade and technology market while adding value to the business. Awareness of the public and of decision makers should be raised on the advantages of fuel cell and hydrogen technologies and their potential in realising the needed transition of the energy system through highly visible demonstration projects. Dedicated fuel cell and hydrogen curricula should be set up for the establishment of a competent work force and of knowledgeable licensing/inspection authorities and emergency responders. All the aforementioned needs aimed at tackling non-technical barriers for market deployment of fuel cell and hydrogen technologies are addressed in the section on cross-cutting activities in the MAIP.

Due to the interdependence of technology progress and enabling policy measures, the actions required for ensuring commercial self-sustainability of fuel cell and hydrogen technologies can only be realised through strong and lasting public-private partnerships. These instruments need further development.

15.5 Synergies with other sectors

Hydrogen competes with other energy carriers for the primary energy sources required for its production. This raises the need to assess and streamline the introduction of hydrogen technologies in an overall energy system transition context. Overcoming common technology barriers and exploiting synergies is most important in centralised systems and in high-volume applications. An example for centralised systems is demonstration of safe CO₂ storage, which is critical for centralised hydrogen production, as well as for continued use of (indigenous) coal for electricity generation. Another is gasification technology, which can be used for production of hydrogen and of second generation biofuels. For high-volume applications, the co-development of electric drivetrains, which share components such as batteries, motors, converters and power electronics with fuel cell electric drivetrains is a potentially important synergy. For automotive applications, adequate interaction and complementarity must be established with the European Green Cars Initiative recently launched in the frame of the European Economic Recovery Plan.

In addition to its direct use as a feedstock for a number of applications in power generation and transport, hydrogen can be used as a storage medium to cope with stochastic power generation from renewable energy sources, requiring interaction and synergy-building with renewable energy and smart grid initiatives. The latter also applies for the integration of the excess power produced by a multitude of distributed small residential generators into the grid.

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16 ELECTRICITY STORAGE IN THE POWER SECTOR

16.1 Technological state of the art and anticipated developments

Demand for electricity storage

Electricity storage has been an integral part of the European energy system for a long time with a broad and diverse application base from customer applications to protect sensitive loads to the support of the electricity grid. Hydropower plants with storage are the most common and widely used storage technologies today at the energy system level, while the lead-acid battery is the dominant technology in commercial, industrial and automotive applications [1, 2, 3].

With an increasing amount of variable electricity production foreseen for meeting the 20 % target of energy consumption from renewable energy sources set at the European level by 2020, it is generally recognised that Europe needs to move towards a fully integrated and flexible European electricity network and market [4, 5, 6]. Increased spatial diversity: improved forecasting, market-based approaches, such as adjustment of the power market designs, time-of-use, demand control, real-time pricing; and grid technology options: cross-border interconnections, HVDC line, power flow control technologies (FACTS, SVC, etc.), smart meters, etc. [7]; are among the main enabling options for the technologies and techniques to accommodate and mitigate variability [1, 8, 9, 10]. There is a consensus within the electricity sector that electricity storage has the potential to play a complementary role alongside those options for improving the manageability, controllability, predictability and flexibility of supply and demand power flows of the European power system [1, 6].

There are two main functions of electricity storage in electricity markets: to balance energy flows and to provide ancillary services¹². Balancing energy flows via electricity storage can, for instance, (i) improve the capacity factors of power plants, hence optimising and matching the energy flows between demand and supply and the power generation economics, (ii) facilitate the valuation and integration of variable electricity production (stable generation, curtailment avoidance in case of excess production with respect to demand and transport capacity) and (iii) provide flexibility and support to electricity grid capacities, e.g. in case of transport capacity bottlenecks and/or, as an investment decision, support for grid infrastructure requiring a long lead time [3, 11]. These capabilities of storage are of significant interest for renewable energy sources, as they offer a technological solution that maximises the usage and benefit of renewable energy production without for instance, having recourse to fossil fuel-based back-up capacity and to curtailment measures in low consumption periods to accommodate variability.

To keep the safety and reliability of the electricity network operation, the grid operators impose interconnection rules to the connected generation device and rely on provision of specialised services at the system level to support maintaining reliable operation of the interconnected transmission and distribution system, the so-called ancillary services¹³. With the increasing amount of and forecasted increase of electricity production from variable energy sources, such as wind and solar, these electricity generation sources are gradually being required to bear the same responsibilities for contributing to power system management as conventional power generation [12, 13]. As a matter of fact, the grid codes setting the connection rules are constantly upgraded and several Member States have revised their codes for high voltage and medium voltage levels to account for the increasing penetration of renewable energy sources, e.g. as in France and Germany [12, 13, 14]. Fault ride-through capabilities, system voltage and frequency limits, active power regulation and frequency

¹² Ancillary services are services necessary to support the transmission of electric power from seller to purchaser given the obligations to maintain reliable operations of the interconnected transmission system

¹³ e.g. frequency control, voltage control, spinning reserve, standing reserve, black start capability, remote automatic generation control, grid loss compensation and emergency control action (Eurelectric 2004)

control, as well as reactive power/power factor/voltage regulation are among the main interconnection obligations at the technology level [12, 13, 15, 16]. These grid code compliance requirements are one of the main influencing, technology development drivers of wind and solar technologies, and consequently, a market opportunity for storage [13, 17, 18].

At the system level, the increased share of variable energy sources in the total electricity production will increase the amount of variability and to some extent unpredictability that must be addressed in system operations, hence leading to changing requirements for ancillary services procurement. A number of research projects are currently investigating the impact and management strategies of large scale integration of variable energy sources in a deregulated environment, e.g. in Europe and North America, with an emphasis on the need for new grid management strategies, market developments for ancillary services and the deployment of purpose-built technology options, as a means to accommodate high deployment levels of these sources [8, 10, 19]. Energy storage systems have been identified as a potential option to provide these ancillary services at the system level [3, 11, 12, 19].

For example, regarding grid integration issues from a wind energy perspective, the main services that could be provided by electricity storage to support wind generation as described in [20] relates to (i) avoidance of transmission curtailment, when the wind farm delivery is constrained by the transmission capacity, (ii) time-shifting, to store energy generated during periods of low demand for discharge during periods of high demand, (iii) forecast hedging, to store energy to mitigate penalties incurred when real-time generation falls short of the amount of generation bid for delivery, and to some extent, (iv) grid frequency support, provision of short duration power necessary to maintain a steady grid frequency within a nominal range following a severe system disturbance caused by, or resulting in, a significant imbalance between generation and load, (v) fluctuation suppression, the energy stored is used to stabilise wind farm generation frequency by absorbing and discharging energy to counter high cycle variations in output and (vi) voltage stabilisation support [20, 21, 22].

These main services dictate both the technical requirements to be met by the storage device (its design) and the market valuation of the cost of the service provided (its economic opportunity). Transmission curtailment, time-shifting and forecast hedging are energy related applications, where the electricity storage system is designed to operate for several hours of discharge, with a nominal capacity of storage plant in the order of 10 to 500 MW. The time response expected for these applications is between 1 to 5 minutes. Grid frequency, voltage stabilisation and fluctuation suppression applications are power related applications, where the electricity storage operates in a discharge mode from a few seconds to less than an hour. The system response time is generally below a few milliseconds [20].

Electricity storage technologies

A wide array of technologies and underlying principles - mechanical, (electro)-chemical and physical - is today available to store electricity, hence providing a large spectrum of performances and capacities for different application environments and energy storage scales [23]. A critical factor for the building of additional storage capacity is its economic performance compared to other alternatives. The economic benefit or market valuation is generally calculated according to the monetary replacement opportunity of an alternative and/or power market economy [20]. Hence, it is strongly dependent on local conditions and operations required from the storage system. The following sections provide an overview of the main applications and input cost and performance parameters. Cost-benefit analyses of different storage devices can be found for instance in [20, 24]. It is noted that, although an interesting option and measure of the benefit and synergy of energy storage devices at large, the possibility of coordinating and managing electricity production from power plants with heat storage such as Concentrated Solar Power Plants to back-up electricity production from variable energy sources is not investigated in this section [25, 26].

16.1.1 Hydropower with storage

Hydropower with storage is a mature technology. Its basic principle is to store energy as the potential energy between two reservoirs at different elevations. Hydropower facilities with storage are usually distinguished in two main categories: hydropower with reservoir and hydro-pumped storage.

Due to their widespread deployment in Europe and the possibility to operate the existing facilities in a more flexible way, hydropower plants with reservoir offer a significant technology base for regulation, hence for accommodating variable electricity production. The large hydropower capacity of Norway and Sweden, supported by the existing common market and good transmission capacity between the two countries, already supports the needs for flexibility and storage of its neighbouring countries, such as Denmark, and attracts more and more interest [27]. Additional grid interconnection capacities are currently planned or under discussion to further exploit the Scandinavian hydropower storage capacity, driven notably by the forecasted large deployment of wind power in the North Sea. This includes the establishment of new grid connections with Germany and the UK, and the reinforcement of the existing connections with the Netherlands and Denmark [27].

A distinctive form of reservoir-based hydropower plants is hydro-pumped storage (PHS). In times of low demand, electricity from the grid is used to pump water to the higher reservoir, while water is released to generate electricity in times of peak demand, hence operating a reversible cycle of grid electricity. It is noted that, in general, when the water resource is limited/strained, the water is recycled in a pumped-storage format [1]. To date, about 100 GW of pure hydro-pumped storage is installed world-wide [2]. In the EU-27 and in the non-EU Member States of the EEA, about 40 GW of hydro-pumped storage are in operation, with Italy, Spain, Germany and France having the largest installed base [28]. Currently, it is estimated that about 75 % of the global potential for hydropower is already developed in Europe [1]. Although there is still a potential for new facilities, it is expected that an important share of the increase in hydro-pumped storage capacity will be made through the retrofit of existing schemes and installation of pumped storage in conventional reservoir-based facilities, where for the latter, many structures are suited for such add-ons. Nonetheless, the potential for additional pumped storage in Europe has yet to be surveyed on a regional/strategic basis.

State of the art pumped storage stations achieve round-trip storage efficiencies in the order of 75 to 85 % [1, 24]. The average plant size in the EU-27 is about 270 MW, with the largest pumped-storage facilities being the Grand'Maison plant located in Isère in France and the Dinowig power station in Wales (UK), producing each about 1800 MW [29]. It is noted that by 2030, about 50 % of the currently installed capacity of hydro-pumped storage in Europe will have to be refurbished due to ageing. The main applications for hydropower storage are wholesale arbitrage, tertiary and secondary reserves, forecast hedging, transmission curtailment, time shifting, etc. However, due notably to the increasing flexibility of the power train and power electronics, provision of power-related ancillary services can also be combined with the above energy-related services [20, 30].

The total capital cost of hydro-pumped storage facilities is very much site-specific and dependent on the use or not of an existing dam infrastructure. The total capital cost for nominal capacities between 200 MW to 500 MW is in the range of 1 000 to 3 600 €/kWe [24, 30, 31, 32, 33]. From a technology point of view, recent advances are mainly related to the double stage regulated pump-turbine, which gives the possibility to utilise a very high head for pumped storage, thus providing higher energy and efficiency, but also variable speed drive allowing wider grid support such as frequency regulation in pumping mode as well as a larger operation window, hence yielding better economics, flexibility and reliability [1]. The reported energy and power accessible domains of hydro-pumped storage facilities lie roughly between 5 MWh to 50 GWh and 1 MW to 5 GW respectively. The time-response from zero to full power is in the order of several minutes [34]. The life-cycle time of hydro-pumped storage

is about 50 to 60 years. Life cycle emissions related to the construction of a PHS storage facility are in the range of 35 tCO₂eq/MWh_e of storage capacity [35].

16.1.2 Compressed Air Energy Storage (CAES)

Compressed air energy storage systems (CAES) are a hybrid form of storage that is already commercially used for large scale energy storage. The underlying principle of CAES is to rely on the elastic energy of the air to store electricity. In a CAES system, the compression cycle of a gas turbine is decoupled from its expansion cycle over time. Air is pre-compressed and stored separately in a geological formation prior to its utilisation in the gas turbine. Grid electricity is used to drive a set of compressors to store the air, and is released when the gas turbine is operated; hence, achieving a storage cycle [23, 36].

Despite its reliance on mature technologies, CAES systems are not widespread around the globe. Up to now, two facilities are in operation, one in Germany in Huntorf built by Alstom Power in 1978, with a rated output power capacity of the 290 MW and the other, McIntosh unit, located in Alabama (USA), owned by the Alabama Electric Co-op and built by Dresser-Rand in 1991, with a rated power output of 110 MW [37]. A new facility with a storage capacity of 150 MW is currently in a planning phase in Iowa (USA) and is expected to be in operation by 2011 [38]. Some of the reasons accounting for this low deployment can be linked to the lack of knowledge and awareness of this technology by the utilities and the necessity to find an adequate geological formation. The main applications for CAES are wholesale arbitrage, tertiary reserves, grid constraints, forecast hedging, transmission curtailment, time shifting, etc. It is noted that CAES can provide combined support to regulation control (system frequency and voltage in combination with load following), in addition to the main application areas described above [30, 36].

Due to the requirement for a geological cavern, the capital cost is site specific. The capital cost is in the range of 400 to 1150 €/kW_e for a plant of nominal capacity of about 300 MW_e [20, 24, 30, 33, 36, 39]. It is noted that small-scale, above ground CAES are currently under development. For these small-scale systems of capacities between 10 to 50 MW_e, the total capital cost is in the range of 750 to 2 600 €/kW_e [20, 24, 30, 33, 40, 41]. The performance of CAES technologies, although based on mature components, are expected to continue to improve mainly due to the possibility of different designs of the basic process, for example, different degrees of intercooling and humidification, development of adiabatic systems [42]. The overall efficiency for a CAES (Diabatic) is about 52 %, including natural gas consumption and about 70 % from an electricity point of view [30, 35, 36]. The life-cycle time of CAES technologies is considered to be similar to a gas turbine lifetime of about 25 to 30 years [24, 30]. Life cycle emissions related to the construction of a CAES storage facility are of the order of 19 tCO₂eq/MWh_e of storage capacity [35]. However, it is noted that the main source of emissions for CAES¹⁴ is linked to the natural gas consumption. The reported energy and power capacity accessible domains of CAES facilities lie roughly between 10 MWh to 10 GWh and 10 MW to 1 GW respectively [34]. The time-response from cold conditions to maximum capacity is of the order of several minutes [43, 44].

16.1.3 Flow batteries

Flow batteries are alternative storage systems for medium scale energy storage. Although to date, there are several manufacturers and units in operation/demonstration worldwide, especially in the USA and Japan, this technology is still in an early-commercialisation phase. Flow batteries rely on the reversible conversion of electro-chemical potential into electricity. As with conventional batteries, a unitary cell consists of two electrodes and an electrolyte. However, in a flow battery, the electrolyte (reactive species) is stored in a tank, hence decoupling the power density (rate of reactions occurring at the

¹⁴ Excluding the emissions generated during the production of the electricity to be stored

electrode) and the energy density proportional to the volume of electrolyte stored. Four main designs are currently being developed: vanadium/vanadium, zinc bromine, polysulphide bromide and zinc cerium [21, 37, 42]. The main applications for flow batteries are wholesale arbitrage, secondary and tertiary reserve, grid constraint, time-shifting and forecast hedging with grid frequency and voltage support and regulation control [20, 23, 30].

Flow batteries have already been tested for wind applications in remote areas, such as King Island in Australia (VRB system). A project is currently being investigated for a 12 MWh energy storage system for the 32 MW Sorne Hill Windfarm in Ireland [45]. The reported round-trip energy efficiency is of the order of 65 to 85 % [30, 43, 46, 47], with a self-discharge rate of about 0.1 % per day [46]. The main progress for flow batteries is expected from development efforts to mature and bridge the gap to mass commercialisation of the current designs, including advances in materials and manufacturing techniques [42].

The total capital cost of flow batteries in the range of 8 to 10 MW and 2 to 4 hours of storage is currently about 2 400 €/kW (1 000 to 3 300 €/kW_e) [20, 24, 30, 33, 48]. The life-cycle time of flow batteries is about 10 to 15 years [24, 30, 43, 46]. It is noted that some parts of a storage facility have longer lifetimes [24]. The time-response from zero to full power is of the order of seconds (less if the electrolyte is primed). The reported energy storage capacity and power accessible domain of flow batteries facilities lie roughly between 100 kWh to 500 MWh and 50 kW to 50 MW respectively. Life cycle emissions related to the construction of a flow battery storage facility are about 160 tCO₂eq/MWh_e of storage capacity [35].

16.1.4 Hydrogen-based energy systems

Hydrogen can be used to store electricity via reversible water electrolysis. Hydrogen produced by electrolysis is transformed back into electricity in times of demand by means of a fuel cell or combustion engine/turbine. The concept of hydrogen-based energy storage is currently in a demonstration phase with a focus on wind applications for remote communities. For instance, the first demonstration project in the Utsira Island in Norway focussed on enhancing wind electricity supply via a hybrid wind/hydrogen system. This project has run satisfactorily for 2 years, although feedback from this project showed that fuel cell systems as integrated components are not technically mature yet. Rather than the stack itself, the main problems came from auxiliaries such as the inverters (frequency variation limitations), the cooling system and the cell voltage monitoring system [49]. As a result, a hydrogen combustion engine had mostly been used. Future research directions aim at a poly-generation (electricity, heat, hydrogen) scheme for remote islands such as the feasibility study project in Nólsoy on the Faroe Islands. Nonetheless, wholesale arbitrage, secondary and tertiary reserve, grid constraint, time-shifting and forecast hedging with grid frequency and voltage support and regulation control are the prime drivers of this storage option in the medium term [20, 30, 37, 49].

The current lines of future technical progress are related to reducing the overall system capital investments, increasing the overall system efficiency, the scale-up of the electrolyzer and fuel cell systems and the increase of the fuel cell durability and lifetime [50]. The reported overall storage efficiency over its complete cycle (electricity-hydrogen-electricity) is about 25 to 30 % [30, 51, 52]. The self-discharge rate is about 0.5 to 2 % per day [46].

The total capital cost for a large-scale system (300 MW / 5 000 MWh) based on electrolysis, salt cavern based storage and open cycle gas turbine is currently estimated to be in the range of 800 to 1 650 €/kW_e [24, 30]. For a fuel cell based system, the cost is currently not known as fuel cell systems are still in the development/demonstration phase, and important cost reductions and performance improvements for fuel cell systems are expected from synergies with the on-going research and demonstration efforts on hydrogen and fuel cell technologies in the transport sector. Preliminary cost

estimates range from 2 000 to 6 600 €/kW_e [24, 30]. The life-cycle time of hydrogen-based energy storage (based on fuel cells) is about 6 to 10 years. It is noted that some parts of a storage facility have longer lifetimes [24, 30].

16.1.5 Secondary batteries

Battery storage technologies rely on electro-chemical reactions to store energy. The energy stored in the chemical bonds of the active material is converted into electrical energy via a set of oxidation/reduction reactions (redox). Different chemical types are currently being used for stationary applications, such as lithium-ion (Li-ion), sodium sulphur (NaS), nickel cadmium (NiCd), nickel metal hydride (Ni-MeH) and lead acid (Pb-acid) batteries [47]. Each of these battery types has its own advantages and disadvantages. NaS are of particular interest for energy management applications. Several demonstration operations have been conducted over the last decade, notably in Japan [37, 47]. By the end of 2008, NaS battery installation from NGK Insulators, the main manufacturer, amounted to 270 MW worldwide, of which 200 MW in Japan alone. The expected market development is about 1 GW installed by 2020 targeting substation upgrade, deferral, peak shaving and wind farm support applications [38]. NaS batteries exhibit efficiencies of about 75 to 85 %, and operate at 300 to 350 °C [30, 37, 47]. An on-going project of 1 MW is currently being built in the Island of La Réunion [1]. The total current capital cost for a NaS-based Storage Plant of 10 MW and 4 hours of storage, including Storage, Balance and Plant and Power electronics, is currently about 1 600 €/kW_e (1 300 to 2 100 €/kW_e) [20, 24, 30, 33, 53, 54].

Lead-acid batteries have a well-established, mature technology base. To date, lead-acid batteries are the most commonly used type of battery in stationary and automotive applications. Despite its low energy density, only moderate efficiency and in some cases, the need for important maintenance requirements, these batteries have a relatively long lifetime and robustness, in addition to low costs when compared to other types of battery. Several large stationary projects based on lead-acid batteries have been performed worldwide to improve grid performances. For example, from 1988 to 1997, a 17 MW/14 MWh battery system has been operated by BEWAG in Berlin for frequency regulation and to provide spinning reserve to Berlin's electricity supply [35, 43]. The total current capital cost for a lead-acid based Storage Plant of 10 MW and 4 hours of storage, including Storage, Balance and Plant and Power electronics, is currently about 1 700 €/kW_e (1 100 and 3 000 €/kW_e) [24, 30, 33, 55].

Lithium batteries are of particular interest, as they rely on the properties of lithium metal, the most electropositive and lightest metal. Therefore, a high energy density storage device can theoretically be achieved in a more compact system. The advantage in using Li metal was first demonstrated in the 1970s and is still the case for important research development worldwide. Lithium-ion is the most mature lithium technology to date. Transport and mobile applications have so far been the main drivers for its development. However, the future prospect of PV energy has recently revived a strong interest in lithium-ion batteries. The costs of lithium battery modules¹⁵ are still quite high. The total current capital cost for a lithium based Storage Plant of 10 MW and 4 hours of storage, including Storage, Balance and Plant and Power electronics, is currently about 4 150 €/kW_e (2 000 and 6 500 €/kW_e) [24, 30, 56]. The round-cycle efficiency of a lithium battery is about 85 % [24, 30]. The self-discharge rates are about 0.03 to 0.1 % per day [46]. Considering Li-ion technology deployment in support of renewable electricity production will require further cost reductions, will in turn require research in materials and manufacturing techniques [47].

The reported energy storage capacity and power accessible domain of battery-based energy storage facilities lies roughly between 1 kWh to 50 MWh and 1 kW to 20 MW respectively. The life-cycle time of lithium-ion batteries is about 10 years. It is noted that some parts of a storage facility have

¹⁵ This cost considers only the energy storage part, and does not include the cost for the Balance of Plant and Power electronics.

longer lifetimes. Estimates for the emissions incurred during the manufacture of lithium-ion batteries range are about 70 tCO₂eq/MWh_e stored [24, 56].

16.1.6 Flywheels

Flywheel systems store energy mechanically in the form of kinetic energy. The core element of a flywheel is a rotating mass which is connected to a main shaft (rotor) powered by an external source of energy. In revolving, the mass builds up inertial energy. This kinetic energy is then released when the rotor is switched off: discharge mode. The use of flywheels as an energy storage device was first proposed for electric vehicles and stationary power back-up in the 1970s. It is still in a demonstration phase for power applications [22, 47]. Flywheel systems are generally distinguished between low speed (up to 5 000 rpm) and high speed systems (50 000 rpm) [23].

One main advantage of flywheel systems is its high cyclability of up to 100 000 to a million cycles. Energy efficiency is above 90 % [24, 30]. The self-discharge rate is quite high at about 20 to 50 % per day [46]. Research and development is currently being pursued to increase the energy density, for instance through increased angular velocity, and to reduce energy losses. However, increasing the rotational speed of the flywheel poses severe constraints on the bearings. Hence, magnetic bearings are used, in addition to maintaining the flywheel housing under a partial pressure or vacuum to reduce the drag force due to high rotational energy. The main drawback of these developments is the high investment cost. The main applications for flywheel are power related such as frequency and voltage regulation [22]. A demonstration project has just been completed for grid frequency regulation in New York State (USA) with a 100 kW/25 kWh (20 min) system. A 20 MW system is envisaged for commercialisation in the near future [22].

The total capital cost for flywheel systems of 20 to 100 MW and 0.25 hours of storage is currently estimated to lie between 2 500 to 3 000 €/kW_e [33], with prospects for the 10th plant to be about 1 350 €/kW_e [22]. Reported energy storage capacity and power accessible domain of flywheel energy storage facilities lie roughly between 50 kW to 20 MW for about one hour. The life-cycle time of flywheel is about 20 years [23, 24]. Estimates for the emissions incurred during the manufacture of a flywheel storage facility are about 384 tCO₂eq/MWh_e stored [57].

16.1.7 Super-capacitors

Super-capacitors rely on the separation of charge at an electric interface to store energy. Super-capacitors consist of two electrodes of opposite polarity immersed in an electrolytic solution. The use of a liquid electrolyte rather than a dielectric solid material is the major difference with conventional capacitors. In these electrochemical systems, the capacitive properties of the electrolyte-electrode interfaces, known as electrochemical double layers, are exploited to store energy [23, 37].

Super-capacitors achieve a high number of cycles, up to 50 000 to 500 000 [23, 37]. The self-discharge rate is about 2 to 40 % per day [8, 37]. Round-trip energy efficiency is between 85 to 98 % [24, 30, 46]. Current values for energy densities are from 0.5 to 5 Wh/kg, whereas power densities can be up to 10 kW/kg. Consequently, super-capacitors are mainly devoted to very short peak power applications. The total capital cost for super-capacitor systems of 1 MW and 10 seconds of storage is currently forecast to be between 200 and 350 €/kW_e [33]. The main applications today are regenerative braking and UPS applications. Coupling of super-capacitors with batteries is a prime option to extend both the peak power capacity of batteries and the energy density of super-capacitors. Nano-carbon materials are currently being investigated as a promising route to increase the energy and power densities of super-capacitors [23]. The life-cycle time of super-capacitors is about 10 years. It is noted that some parts of a storage facility have longer lifetimes [24].

16.1.8 Superconducting Magnetic Energy Storage (SMES)

Superconducting Magnetic Energy Storage (SMES) is a relatively new power storage technology that stores energy in a magnetic field created by a DC current. Once a DC electric current is injected into a superconducting coil, it creates a magnetic field in which energy is stored. It is then released when this closed circuit is opened. The response time of SMES is less than a few milliseconds. Up to now, coils are mainly built from NbTi and cooled by liquid helium. SMES has been developed for use in high-power devices, hence for power quality applications [47]. The main applications foreseen for SMES systems are voltage fluctuations and fault-ride through support [20, 57, 58].

SMES develops high efficiency of storage in the order of 95 %, including energy losses associated with the cooling system [24, 30, 47]. To date, only micro-SMES (1 to 10 MW) are commercialised [47]. One US-based company provides trailer-sized SMES that store roughly 3 MVAs and provides roughly 2 MW [58]. In Europe, research prototypes are being developed in the order of 1 MW in Germany, Finland, Spain and Italy. The total capital cost for SMES of 1 MW and 1 second of storage is currently forecast to lie between 250 and 400 €/kW [33]. One of the major lines of progress of SMES is to develop high-temperature superconductor technology to reduce their cost. Successful demonstration projects operating at 20 K have been run in Germany, Finland, the USA and South Korea [47]. However, additional research on these high temperature materials is needed, for instance, to increase the critical current and magnetic field and to develop manufacturing processes enabling high production volumes.

At present, the reported energy storage capacity and power accessible domain of SMES lies roughly between less than 1 kWh to 10 kWh and 1 MW to 10 MW respectively, with a long term objective for large scale SMES of about 100 MW, with up to 50 kWh with efficiencies of 99 % and a lifetime of 40 years based on high-temperature superconductors [34, 47]. Estimates for the emissions incurred during the manufacture of SMES storage facilities are about 962 tCO₂eq/MWh_e stored [57].

16.2 Market and industry status and potential

Currently, storage capacities operated in Europe are mostly in the form of hydro-storage [28]. As an optimisation technology, forecasting the future needs in storage capacity is strongly dependent on other developments, especially the future electricity technology mix, e.g. level of variable energy source, and the capacity of the EU grid infrastructure to accommodate variable power generation. To date, there are no agreed scenarios on the requirement for additional storage capacities in Europe [1]. Several market uncertainties are currently hindering reliable prediction on the need for electricity storage: uncertainties on the level of variable renewable capacity that will be implemented by 2020, uncertainty on the level of low carbon base-load technology deployment such as nuclear energy, uncertainty on the level of demand side measure effectiveness to curb and peak shave energy consumption. In other words, there is a need to advance further the analytical framework on the requirement of electricity storage [1]. Establishing a consensus and common assessment framework for electricity storage is currently prioritised within the Information System of the SET-Plan (SETIS).

The European industry has currently a strong market leadership in large scale energy storage technology. Three market leaders for hydro-pumped storage are based in Europe. One European company alone owns 40 % of the market share worldwide. However, it is stressed that international competition is intense, as the main market developments are happening outside Europe. Although the European know-how and technology is widely used worldwide, international competitors are entering the market at a fast pace. Signs are already visible in China. There is a need to maintain this European industrial excellence and leadership [1]. Similarly, although Compressed Air Energy Storage technologies are not widely deployed, one of the two projects currently in operation was built with European technologies. In addition, European manufacturers are active in evaluating advanced CAES

concepts such as adiabatic CAES. For Hydrogen and Fuel cell technologies, the establishment of a Joint Undertaking in 2008 will contribute to the development and strengthening of European Industry.

For intermediate or smaller scale technologies, the European industrial base is weaker. Flywheels and flow battery manufacturers are mostly based outside Europe. There is a need to achieve European technological leadership in this area. For batteries and super-capacitors, although there are world-class European manufacturers, the overall battery market is dominated by Asian manufacturers. This contrasts with the excellence of European research at the origin of decisive breakthroughs in the past 30 years that enabled the commercialisation of lithium batteries. As this market is expected to grow significantly in the coming decades, for instance due to the growth of photovoltaic energy, there is a time window to strengthen the European Industry [1]. The recently created European virtual research centre ALISTORE to consolidate European research on advanced lithium batteries and the recent launch of a Franco-German industrial project to provide grid-connected PV systems equipped with lithium-ion batteries are indicators of the potential of Europe to play a critical role in this field [59].

16.3 Barriers

The main barriers facing electricity storage can be summarised into four categories: market uncertainty (composition of the future electricity technology mix, future level of interconnection and integration of the European electricity market); market structure and regulation to consider and reward the multiple services at multiple levels provided by electricity storage, e.g. power generation vs grid investment, fully developed and priced ancillary services market; current electricity pricing and economics; and performance of storage technologies [1, 3].

One of the main economic hurdles for investment in storage technologies, such as pumped storage, is the current tariff structure in several European markets that considers grid fees for both consumption and generation [1, 60]. Some Member States are already taking measures to improve this situation by, for instance, not charging network access for storage facilities for a certain number of years [61]. Furthermore, the capacity of electricity storage to provide multiple services in transmission, distribution and generation markets, e.g. renewable integration support, grid up-grade and ancillary services, leads to a level of uncertainty with respect to how investments in energy storage will be recovered when all/multiple services are not yet properly regulated and commercialised. Finally, the current pricing structure which does not account for time of use or real-time prices does not provide sufficient incentive to invest in energy storage applications.

More specifically for hydro-pumped storage, one of the major issues for its deployment is the capacity to build market-attractive business cases in the current market regulation framework. At present, experts consider that the existing practice of the EU ETS linking Directive (Directive 2004/101/EC) and its eligibility criteria framework for hydropower plants over 20 MW, put additional constraints on these large scale systems, hence currently reducing the possibility of introducing new electricity hydro-storage projects [1].

The rest of the technology portfolio, due to its maturity, faces at this stage, barriers of a more technological nature, although sustained RD&D is also required for hydro-pumped storage (see 17.1.1.). The majority of these technologies still require research and development efforts to reduce the cost and improve performances. Current investment in R&D projects is not synchronised with the requirements in storage technologies. Bringing the technologies to a stage of commercial maturity and accelerating the transition to mass commercialisation are two key priorities. Equally important is to ensure that manufacturing capacities will not become a bottleneck in the case of a massive deployment of storage technologies in the coming decades.

Finally, there is the risk that the large scale deployment of variable power sources in the European power system is desynchronised with the upgrade of the grid infrastructure and the development of storage capacity. There is a need to anticipate investments in storage capacity with a European perspective. In this respect, the development in the North Sea area with additional interconnections being built to reach out the hydropower potential of Norway and Sweden, reveals the importance of such an approach [27].

16.4 Needs

With the increasing penetration of variable energy sources, there is a need to (i) further develop regulatory aspects on power quality requirements at the European level under high penetration of distributed and variable energy sources, (ii) to address the specificity and benefits of electricity storage in the design and regulatory framework of the electricity market to support the build-up of business cases for electricity storage projects, e.g. fully developed ancillary services market, integration of storage in renewable support and grid planning, as well as (iii) to strategically address, at the European level, the transition towards a low carbon power system in order to maximise and synchronise investments in electricity generation, transmission and supporting assets. For example, the current hydropower system, with its regional diversity, can be further operated in a more flexible way and provide additional storage capacity to the European system as a whole, provided grid connections are in place [27]. On the technology front, there is a need for both industrial-scale demonstration projects for near-to-market deployment technologies, such as, for example, Compressed Air Energy Storage and Lithium-ion batteries in order to build industrial confidence and gain field experience, and for sustained research and development programmes on advanced storage technologies and materials. Furthermore, there is a strong need to establish a consensus and a common assessment framework for the evaluation of electricity storage market potential and economics to enable the industry and public authorities to make decisions for investments on and support electricity storage developments [1].

16.5 Synergies with other sectors

The on-going efforts to electrify the road transport sector via the development of alternative drive-trains such as plug-in hybrid vehicles or fuel cell vehicles provides a clear ground for synergies in research and development on batteries and fuel cells. A key issue is the power conditioning system of storage plants and their management control tools which are critical for their integration in the electricity network and the provision of ancillary services, strong synergies need to be made with power electronics and ICT and smart grid technologies. There are also cross-synergies within the power sector due to the use of common components with hydropower plants and gas turbines in the case of Compressed Air Energy Storage. Finally, with the strategic importance of storage for the overhaul of the electricity network, strategic planning at the European level is required to inscribe storage technology and regulatory developments in the broader context of activities on smart grids and renewable integration.

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17 EFFICIENCY IN ROAD TRANSPORT

17.1 Technological state of the art and anticipated developments

Mobility of persons and goods is an essential component of the competitiveness of European industry and services; mobility is also an essential right of the citizen. The goal of the EU's sustainable transport policy is to ensure that our transport systems meet society's economic, social and environmental needs, as highlighted by the mid-term review of the 2001 White Paper: "Keep Europe moving". Effective transportation systems are essential for Europe's prosperity, having significant impact on economic growth, social development and the environment.

In 2006, the transport sector consumed 31.4% of the total final energy consumption¹⁶ (of which 81.9 % is road transport) and was responsible for 24.6 % of CO₂ emissions (EU-27) [1]. In 2007, road transport constituted about 83.1 % of total transport demand in passenger transport and 45.6 % in freight transport (EU-27) [1]. Road transport accounts for 71 % of transport-related CO₂ emissions and passenger cars constitute 63 % of these road transport related CO₂ emissions¹⁷. In this section only technologies in road transport (focussing on passenger cars) have been considered. Road transport is almost totally dependent on fuel oil, making it very sensitive to market volatility of crude oil (security of energy supply).

17.1.1 Conventional vehicles

In 2007, there were 229.8 million passenger vehicles in the EU-27 [1] and new vehicle sales were 15.96 million vehicles in that year¹⁸. At present, the reciprocating internal combustion engine (ICE), either as homogeneous charge spark ignition (petrol engines) or stratified charge compression ignition (diesel engines), dominates the drive trains of road vehicles. The market share of these two technologies is at present about 50:50 in new passenger and light duty cars in Europe. However, the market share of diesel vehicles is likely to further increase in the near future because of their better fuel economy. The current, average retail price of a state of the art compact class petrol vehicle (port fuel injection) is EUR 18 600, while the average compact class diesel vehicle price is EUR 20 300 [2]. The average emission from new cars registered in the EU-25 in 2007, amounted to 158 gCO₂/km TtW (tank-to-wheel), which is a 15.1 % improvement versus 1995 [3]. The improvement is due to a mix of overlying factors, such as vehicle technical improvements, changes in market share, etc. Gains in energy efficiency in internal combustion engines are still possible. However, it is widely recognised that after years of large gains, only small incremental improvements can be foreseen by technical development of the current state-of-the-art technology.

There are several means to reduce the fuel-to-energy consumption in petrol engines: variable valve timing and actuation or even replacing mechanical camshafts and using fully flexible electro-hydraulic or electro-mechanic valves to reduce throttling losses; varying the compression ratio during the operation of the engine; reduction of the number of cylinders or cylinder deactivation under certain driving conditions; thus reducing the swept volume, such that friction losses are minimized and average engine loads are increased. However, these developments reduce drivability (acceleration times). A possible solution is to supercharge the engine, but "downsized and supercharged" (DSC) engines might result in sluggish torque dynamics. Furthermore, the use of direct injection and lean burn combustion ("lean burn direct injection petrol engines") can lead to a very significant reduction (up to 20 %) of fuel consumption. However, this engine strategy prevents the use of the Three Way

¹⁶ Final energy consumption covers all energy delivered to the final consumer's door (in industry, transport, household and other sectors) for all energy uses. Deliveries for transformation and/or own use of the energy-producing industries, as well as network losses, are however not included.

¹⁷ Derived from TREMOVE data.

¹⁸ ACEA data.

Catalyst and therefore to meet emission limits, an efficient De-NO_x system is required, leading to additional vehicle costs of roughly €500 (for the injection and after-treatment system) [2]. A reasonable combination of the above list of technologies could lead to approximately 20 % vehicle CO₂ reduction for roughly €1 500¹⁹ additional vehicle costs versus today's petrol vehicles [4].

Turbo-charged diesel engines using the “common rail” direct injection system are an established technology and already offer 20 % fuel savings over petrol engines. Advanced technologies (Clean Diesel Engines), such as variable-valve control and fully-variable direct injection systems, can further improve the fuel efficiency of compression ignition engines, even if stricter pollutant emission regulations will increasingly require active emissions control (such as in cylinder pressure sensing, particulate filters and NO_x traps). This development might reduce slightly their fuel-economy benefits and, more importantly, further increase the system costs. A reasonable combination of the above technologies could lead to approximately 10 % vehicle CO₂ reduction for roughly €1 000 additional vehicle costs versus today's diesel vehicles [4].

Fuel savings due to improved aerodynamics, lightweight technologies, energy efficient tyres and more-efficient, on-board accessories can provide extra gains in fuel-to-energy efficiency for both ICE vehicle types. Further evolution of ICT in vehicles and in road infrastructure can contribute to additional fuel savings in real-life traffic through traffic flow management, avoidance of congestion and assistance in search for parking spaces.

An important development in ICE technology is the Homogeneous Charge Compression Ignition (HCCI) engine. HCCI shares characteristics belonging to the homogeneous charge spark ignition (petrol engines) and the stratified charge compression ignition (diesel engines). The main characteristic of HCCI is that the combustion takes place spontaneously and homogeneously without flame propagation in the combustion chamber. There is no direct initiator of combustion. Therefore this type of engine shares the gain in efficiency of the diesel engine and the low emissions of the petrol engine. At present, there are several challenges that the HCCI needs to overcome: the control of the ignition is difficult to achieve and the control of the auto-ignition goes hand-in-hand with its efficiency and its exhaust gases, since operating at certain conditions with high efficiency but high emissions is clearly not the purpose. Altogether, it is estimated that HCCI technology could lead to approximately 12 % efficiency gains for roughly €1 400 additional vehicle costs versus today's petrol vehicles [4].

17.1.2 Alternative vehicle concepts

Electrification of drive trains might offer a step change technology, based on the much higher efficiency of electric motors compared to ICEs [2], as well as the potential to decarbonise the well-to-tank pathway. This path will also open the possibility to use alternative energy paths to secure mobility and make road transport more independent from crude oil (security of energy supply). As an intermediate step, the introduction of start-stop functionality, associated with electrification of ancillary equipment in the vehicle, might pave the way to electrification, providing, at the same time, some gains in energy efficiency.

Three types of electrical vehicles will be addressed in this chapter, namely: Battery electrical vehicles (BEV), Hybrid electrical vehicles (HEV) and Plug-in hybrid electrical vehicles (PHEV). Hydrogen Fuel Cell vehicles (HFCV) are discussed in Chapter 15.

- A **BEV** (or pure electrical vehicle) is powered by an electrical motor rather than ICE. The needed electrical energy is provided by rechargeable batteries. They do not produce any exhaust emissions, but they are responsible for some emissions on a well-to-wheel (WtW) basis depending

¹⁹ In this report the values are expressed in € using when necessary a conversion rate of 1.4 US\$/€

on the electricity production technology used to charge the batteries. Usually, BEVs are equipped with regenerative braking to recuperate part of the energy delivered by the drive train to the vehicle by directing it to recharge the battery. The BEV market is quite small although at present, the market is expanding. The central part of the BEV is the rechargeable electrical storage system, i.e. the battery. Recent developments in battery technology could make BEVs viable for the mass market. Lithium ion batteries that are well known from consumer electronics is currently the technology that displays the greatest potential for use with electrical vehicles. The greatest challenges for using lithium ion batteries in the automotive environment are costs, weight, durability, life cycle and temperature sensitivity. Recharging time is another key issue for market acceptance. With CO₂ emissions of approximately 450 g CO₂ per kWh electricity (net) in the EU mix²⁰ and a demand of roughly 15 – 20 kWh per 100 km, this could lead to 68 – 90 g WtW CO₂ emissions per km versus roughly 180 g WtW CO₂ emissions per km of the currently available new vehicle fleet (that corresponds to the 158 g TtW emissions of the new vehicle fleet)²¹.

The future increasing share of renewable resources for energy generation in the EU (Directive 2009/28/EC) would further improve the WtW numbers for BEVs and PHEVs.

- The term hybrid refers to the fact that these vehicles can use different energy resources in combination. Generally it refers to **HEV** which are powered by a drive-train that combines an ICE and an electrical motor. HEV present several engine architectures with different sizes for the ICE and the electrical motor and each of the architectures provide different trade-off in terms of cost, efficiency and performance.

In a series HEV, the ICE is used to charge an on-board battery or supply directly electrical power to the electrical motor which drives the wheel and the accessories. This architecture is closer to the one used by BEV. As in the case for BEV, they can use regenerating braking to recover part of the spent electrical energy. An advantage of this architecture is that the ICE engine is de-coupled from the load due to road conditions and can be set to work at certain operating points, where its efficiency is high.

In a parallel HEV, both the ICE and the electrical motor can propel the vehicle or they can be used simultaneously for maximum power. Further, HEV can be categorised as either a “mild” or “full” hybrid. In a “mild” HEV, the electrical motor acts as a starter and can serve as an alternator during braking (regenerative braking), while the ICE mainly powers the drive train. This “assist” hybrid or start-stop configuration may improve fuel economy by nearly 20 % as compared to a pure ICE vehicle, at an additional vehicle cost of €3 000 [5]. In a “full” HEV, the operation can be fully provided by the ICE, in either hybrid mode or in all-electrical mode. The latter case is mainly used for cold starts and for short driving ranges at low speeds (actual full hybrids have a very short all-electrical operation – about 5 min.). The use of the electrical motor allows for a reduction in the size of the ICE and thus the fuel-to-energy consumption. Although the performance of this type of HEV depends strongly on the driver’s driving style, it can be said that the potential fuel saving in a smooth driving style in an urban environment is of 30 to 40 % [5], with a projected additional vehicle cost in 2010 of €7 000 [2].

As in the case of BEV, reducing the cost, weight and size of the batteries is the greatest technology challenge for this type of vehicle, despite the higher complexity and cost of such vehicles. A possible improvement for HEV is the use of diesel ICE rather than petrol ones to further gain in fuel-to-energy efficiency, making with this combination, possibly the most efficient vehicle in the long run.

²⁰ Calculated from PRIMES data.

²¹ Own expert calculation.

- A middle of the road concept between BEV and HEV is the **PHEV**, as it combines the advantages offered by HEV and the opportunities offered by having a larger, on-board battery close to that of a full BEV. In PHEV, electricity can be loaded into the vehicle either from the grid or through on-board electricity generation using ICE or even fuel cells (see Chapter 15). PHEV's main advantages would be increased flexibility and longer driving range, but at possibly higher costs. Both concepts, BEV and PHEV, provide zero emission ranges. For PHEV, this would be somewhere between 20 and 60 km, while for the BEV, of the order, to be viable, well above 100 km.

In the IEA Energy Technology Perspectives 2008, additional vehicle costs are estimated to be €17 900 for BEVs in 2015 and €6 400 for 2030, while the estimated additional costs for PHEVs is €3 800 for 2015 and €2 600 for 2030 [6]. Other sources estimate additional vehicle costs of €10 000 for BEVs in 2020 and roughly €5 000 additional costs for PHEV over the same time frame [4].

For hybrid vehicles, in particular, additional efficiency improvements could be realised in the long term through the use of thermo-electric generators..

17.2 Market and industry status and potential

The European vehicle industry gives, directly and indirectly, employment to 12.6 million people in the EU-27. This is roughly 6 % of the total EU employment. The automotive sector is Europe's largest private investor in R&D with EUR 20 billion each year or 4 % of turnover²². Over the last decades, the European industry has contributed to major industry breakthroughs, such as the common rail direct injection for diesel engines. Many initiatives to make vehicles more efficient have been fostered by an integral network of research providers and industry. The European industry base is comprised of large multinational companies and innovative small and medium enterprises (SMEs). While starter batteries are a well-known, rather low cost commodity for the OEMs (original equipment manufacturers), traction batteries will play a much more prominent role in the value chain of hybrid and electrical vehicles. This will also re-define the collaboration between the automotive industry and battery technology suppliers, with research institutes in the near future. The market presence of traction battery suppliers and manufacturing facilities in Europe is low compared to Asia and the US.

Direct CO₂ emissions from road transportation amounted to 902 Mt CO₂ in the EU-27 in 2006 and energy consumption was 300.4 Mtoe [1]. Due to an increasing transport demand, it is expected that transport related energy consumption will rise to more than 350 Mtoe by 2030 despite efficiency improvements through vehicle technology and alternative fuels [7].

Many of the above listed technologies that focus on improvements of the internal combustion engine and reduction of the vehicle road load will have to be implemented to meet the 2012 - 2015 specific CO₂ targets for passenger cars [Regulation (EC) No 443/2009]. This will lead to a CO₂ emission avoidance of roughly 70 Mt CO₂ in 2020. The 95 g CO₂ target for 2020, as laid down in EC 443/2009, will additionally require the mass market roll-out of more advanced technologies such as strong hybrids, electrical vehicles and hydrogen fuel cell vehicles.

The current BEV and PHEV market share in the EU is very low. While this is also true for Asia and the US, Hybrid shares are already much higher in Japan and the US versus Europe, mainly because of the very low share of diesel vehicles in these passenger car markets. The main players with respect to currently available Hybrid technology are Japanese OEMs (Honda: currently > 300 000 cumulative Hybrid sales globally, Toyota: currently > 1.5 million cumulative Hybrid sales globally) with recently, an increased effort of US-based OEMs to increase their market presence with respect to Hybrid

²² ACEA figures

vehicles. A small number of vehicles from niche manufacturers and fleet test vehicles from larger OEMs are on European roads today. Several OEMs have announced roll-out plans for BEVs and PHEVs. The technology platforms ERTRAC (European Road Transport Advisory Council) and EPoSS (European Technology Platform on Smart Systems Integration) developed an industry roadmap for 5 million electrical and plug-in hybrid vehicles in the EU by 2020, with annual sales of 1.5 million vehicles. This is in line with individual initiatives of various member states for the roll-out of these vehicles. A more conservative outlook, with respect to future BEV and PHEV market penetration, is given by own-expert knowledge in order to provide a lower bandwidth scenario. This forecasts a stock in 2020 of 0.4 % (~ 1 million) BEVs and 0.7 % (~ 1.7 million) PHEVs, with sales of 0.2 and 0.4 millions per year for BEV and PHEV respectively in 2020.

Using the current EU-27 electricity mix as energy source for the BEVs and the electrical drive portion of the PHEVs, the lower bandwidth scenario would lead to approximately 2.4 Mt CO₂ avoidance in 2020, while the ERTRAC/EPoSS scenario could lead to approximately 4.7 Mt CO₂ avoidance in 2020. With a higher share of renewable resources for the future EU-27 electricity generation, these potential CO₂ avoidances could be further increased. The resulting displacement of petroleum-based fuel through the increased usage of BEVs and PHEVs would have an important positive effect on the security of supply.

17.3 Barriers

For battery vehicles, the prime challenge is the low-energy density of available batteries, which limits the range of driving between charges. The lack of robust high power and high energy battery systems for mobile applications is a major bottleneck: lead-acid batteries are cheap (ca. €100 per kWh) [8], too heavy (low energy and power density) and lack deep cycling capability, while other battery technologies, although they can double the vehicle's driving autonomy and last longer than lead-acid batteries, are still too expensive (NiMh or Li-Ion, ca. 500 – 1500 €/kWh) [8]. On the other hand, the widespread use of BEVs and PHEVs will be delayed unless social and infrastructural barriers are addressed in addition to technological development. Standardised electric infrastructures, e.g. re-charging points, will need to be provided.

The high cost of vehicles and their batteries (including warranty) are widely considered as one of the main barriers for uptake of the technology. Therefore, vehicle-to-grid (V2G) technology, also known as 'mobile energy' or 'smart charging' associated with incentives for back-metering, could help to lower the cost of EV for the consumer and therefore overcome social resistance to EV. Furthermore, it has been found that consumers expect unrealistically short times (< 5 months) to recover their investment in EV.

The inertia of the current transportation system and the major market players can be potentially a significant market barrier. The way to an electrified road transportation system is associated with high infrastructural investments, be it in manufacturing facilities, service and maintenance or charge points. Additionally, electric utility companies will have to define their role in order to become a new player in road transportation.

17.4 Needs

The challenge to develop an electrified road transportation system depends upon strong research programmes to develop suitable basic technologies together with the appropriate system integration.

- **Storage systems:** On-board storage of electricity is the main challenge. The batteries need to increase their energy density, safety and lifetime, while reducing their cost, as well as the re-charging time. Today's battery research is focussed on high power technology mainly oriented to

HEV, while for BEV and PHEV high energy batteries are required. The target is to reach high energy density batteries above 200 Wh/kg. With the use of alternative electrochemical components, safety of the cell is critical and in particular, to avoid possible thermal runaway. Therefore, it is important to develop safe high energy systems. All these requirements need further understanding of the electrochemistry, in order to extend the lifetime of the batteries.

- **Electric motor (EM):** The main challenge for EM is possibly its coexistence with combustion engines in HEVs, the same is applicable to the power electronics. Therefore, an increase in EM performance (power and torque) with a reduction of its volume and weight is required. In addition, the EM needs to operate in a harsh environment and care is needed to reduce losses and increase their efficiency per volume. This might be met by developing new materials, magnets and insulation material or even with new EM concepts.
- **System architecture:** The main research need is the integration of the power-train system to minimise cost and optimise efficiency. This also includes research in power electronics components, addressing thermal system management, as well as high frequency switching components. Key points, relating to the storage systems, is the development of reliable battery charging and discharging algorithms, including monitoring and switching (on/off) of individual cells.

Concerning the ICE in HEVs, managing its efficiency by considering the traffic situation needs to be addressed. ICE downsizing, high pressure supercharging and simplification and integration of the control electronics are important topics to be considered.

- **Infrastructure:** V2G, as addressed later in this chapter, adds functionality to the EVs. A V2G system needs to be aware of the user's charging needs and the state of the grid. Therefore, the development of basic control algorithms and hardware, user's acceptance and a new business model as interface, needs to be considered at an earlier stage. Other enablers in the integration of EV are the on-board charging and metering devices and their connection to the grid by V2G interfaces. Finally, the capability to provide charging points on streets will strongly support an early acceptance of EVs.
- **Demonstration and fleet tests:** Demonstration and field tests need to be conducted in order to generate know-how with respect to daily usage and customer feedback of PHEVs and BEVs.

The above R&D measures will be able to address some of the barriers for the electrification of the road transportation system. They might need to be complemented by additional market stimulus measures in order to reach a market deployment of BEVs and PHEVs in Europe.

17.5 Synergies with other sectors

Strong synergies with the electric utility sector exist concerning re-charging infrastructures and grid management via batteries, especially also concerning energy storage technologies. V2G technology will be a key to achieve widespread use of EVs. V2G technology would see "intelligent" recognition between the grid and the vehicles, being able to manage the energy flow from and to the vehicle and using the vehicle as part of a distributed energy storage system to smooth power peaks. A V2G system has to be a smart system, anticipating and 'knowing' the user's charging needs, the state of the electrical grid and providing new functionalities. It will give rise also to new business opportunities at the interface between the EV and the electricity suppliers. It also might give rise to new concepts, such as vehicle-to-home (V2H) functionality.

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Abstract

The *Technology Descriptions* of the 2009 Technology Map assess the technological state of the art and anticipated developments of 17 energy technologies, the status of the corresponding industries and their potential, the barriers to large scale deployment, the needs of the industrial sector to realise the technology goals and the synergies with other sectors. The technologies addressed are: wind power, solar photovoltaics, concentrated solar power, hydropower, geothermal energy, ocean energy, cogeneration of heat and power, carbon capture and storage, advanced fossil fuel power generation, nuclear fission, nuclear fusion, electricity grids, bioenergy for power generation, biofuels for transport applications, fuel cell and hydrogen technologies, electricity storage and energy efficiency in transport. The 2009 Technology Map is the SET-Plan reference on the state of knowledge for low carbon technology in Europe, presenting a snapshot of the energy technology market situation for 2008-2009. However, the information in this work should be seen in the context of the dynamics of the energy technology market. As such, SETIS is continuously tracking and monitoring the global development and progress of energy technologies and makes this information available “on-line” in the SETIS website: <http://setis.ec.europa.eu>.

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