ATTACHMENT 11

GLOBAL OVERVIEW ON GRID-PARITY EVENT DYNAMICS

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ABSTRACT

Grid-parity is a very important milestone for further photovoltaic (PV) diffusion. A grid-parity model is presented, which is based on levelized cost of electricity (LCOE) coupled with the experience curve approach. Relevant assumptions for the model are given and its key driving forces are discussed in detail. Results of the analysis are shown for more than 150 countries and a total of 305 market segments all over the world. High PV industry growth rates enable a fast reduction of LCOE. Depletion of fossil fuel resources and climate change mitigation forces societies to internalize these effects and pave the way for sustainable energy technologies. First grid-parity events occur right now. The 2010s are characterized by ongoing grid-parity events throughout the most regions in the world, reaching an addressable market of about 75% up to 90% of total global electricity market. In consequence, new political frameworks for maximizing social benefits will be required. In parallel, PV industry tackle its next milestone, fuel-parity. In conclusion, PV is on the pathway to become a highly competitive energy technology.

Keywords

Grid-parity, Fuel-parity, Economic Analysis, Energy Options, PV Markets, Modelling, Sustainable, Strategy

1 INTRODUCTION

Installations of Photovoltaic (PV) power plants have shown high growth rates around the world.[1] As a consequence of this growth PV electricity generation cost continuously decreases. The contrary trend is shown by electricity prices for end-users. The intersection of these two trends is defined as grid-parity and indicates cost neutral PV installations. The purpose of the present study is a detailed analysis of global grid-parity event dynamics for nearly all countries in the world and respective residential and industrial market segments in the years to come. Key motivation of this work was to learn more about the geographic and temporal distribution in the occurrence of grid-parity in the world.

This paper presents a detailed analysis of grid-parity dynamics based on the levelized cost of electricity (LCOE) concept coupled with the experience curve approach (section 2) including a broad discussion of the key driving forces of the model (section 3). Results of the analysis are shown for Europe, the Americas, Africa and the Asia-Pacific region (section 4). Finally, consequences of these results are discussed (section 4 and 5).

This conference contribution presents results of Q-Cells research. First results for Europe had been a cornerstone that led to the 12% supply target of European electricity demand by 2020 of the European Photovoltaic Industry Association (EPIA) as announced on the 23rd PVSEC in Valencia in 2008.[2,3] Results for the US had been published first in the US [4] and together with all European Union (EU) member states on the 24th PVSEC in Hamburg in 2009.[5] Results for Japan, India, Middle East and North Africa (MENA) and Asia had been presented at respective regional conferences.[6-9] In this study we present results for 151 countries plus some regional aggregations of the US, India and China. We now cover 98.0% of world population and 99.7% of global gross domestic product (GDP), therefore we have now finalised our work of the last years focussed on understanding global grid-parity event dynamics.

2 GRID-PARITY MODEL

In history of PV three major inventions led to sustainable markets for PV systems (Figure 1). The first PV market diffusion phase started after introducing PV power supply in space as least cost option, which was achieved only a few years after pioneering results in silicon based solar cell research by Darryl Chapin, Calvin Fuller and Gerald Pearson in 1954.[10] As a consequence of the oil-price crises in 1970s PV applications started the second PV diffusion phase. Off-grid applications have been growing after former space technology was brought to earth by Elliot Berman due to his invention of the terrestrial PV module concept.[11] PV has become the least cost option for off-grid rural electrification, in particular in developing countries.[12] The third PV market diffusion phase has been enabled by the political invention of roof-top programmes and feed-in tariff (FiT) laws.[13,14] Right now, the third PV diffusion phase can be observed: grid-parity in residential markets throughout the world. This paper gives some insights for the third PV market diffusion. On the horizon one can already recognize the fourth diffusion phase: commercial utility-scale PV power plants.[8,15,16] A good overview on PV diffusion patterns is given by Andersson and Jacobsson.[17]

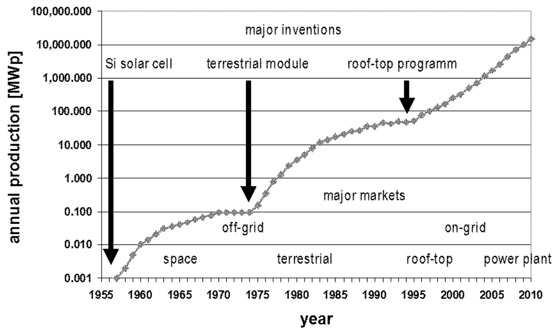

Figure 1: Historic PV production in dependence of major inventions and market segments. Notably, annual growth rates increased from about 33% in space age and during off-grid diffusion to 45% for the last 15 years during on-grid diffusion. Figure and underlying trends are discussed in more detail elsewhere.[18]

For analysing the third PV market diffusion phase a dynamic grid-parity model has been designed.[19] The outcome is a time and geography dependent investigation method for sustainable market potentials of PV for the considered countries. Each country is represented by the two major market segments of residential and industrial customers (users). PV generation costs are calculated by the LCOE method [20] and compared to the electricity prices of market segments in respective countries. It has to be mentioned, that no subsidies for PV are taken into account, i.e. real PV costs are regarded. It was neither possible nor intended to exclude various subsidies in the global electricity markets. These direct financial subsidies for fossil fuels are estimated to about 3 10 and 20 – 30 bnUSD per year for non-OECD and OECD countries, respectively.[21,22]

Using the **LCOE method** (Equation 1) one can easily transform the cost/Wp numbers usually used in PV industry into the more decisive cost/kWh category of the power industry. All cost categories, i.e. investment and capital expenditures (Capex), operation and maintenance expenditures (Opex), have to be put on an annual basis. LCOE are obtained by dividing annual costs by annual electricity generation. LCOE enables a direct comparison of alternative energy technologies in terms of cost per energy, in this paper €/kWh.

$$LCOE = \frac{Capex \cdot crf + Opex}{E_{net}} \qquad \text{(Eq. 1.1)}$$

$$crf = \frac{WACC \cdot (1+WACC)^N}{(1+WACC)^N - 1} + k_{ins} \qquad \text{(Eq. 1.2)}$$

$$WACC = \frac{E}{E+D} \cdot k_E + \frac{D}{E+D} \cdot k_D \qquad \text{(Eq. 1.3)}$$

Equation 1: Levelized cost of electricity (LCOE). Abbreviations stand for: capital expenditures (*Capex*), annual operation and maintenance expenditures (*Opex*), net electrical energy yield (E_{net}), annuity factor (*crf*), weighted average cost of capital, (*WACC*), lifetime of PV system, (*N*), annual insurance cost in percent of Capex (k_{ins}), equity (*E*), dept (*D*), return of equity (k_E), and cost of dept (k_D).

The input parameters for LCOE formula are mainly dependent on circumstances regarding geography, time, energy and financial markets. Net generated energy is a function of local solar irradiance, which is given by latitude and average annual weather conditions of a specific site.[23] Capital expenditures for PV systems are derived from the empirical experience curve for PV (Equation 2 and Figure 3) further described below, which depends on the growth rate of global PV markets (Figure 1) and hence, on time and the general energy markets. The interdependencies of these key driving forces are discussed in detail in section 3.

For analysing the grid-parity dynamics in time (section 4) the critical input parameters are the progress ratio of PV, the growth rate of the global PV industry, both key drivers of the experience curve, and the electricity price trends.

The **experience curve** approach is an empirical law of cost reduction in industries[24] and was first discovered in aviation and shipbuilding industry in the 1930s to 1950s.[25,26] It was observed that per each doubling of cumulated output the specific cost decrease by a nearly stable percentage (Equation 2). This stable cost reduction is defined as learning or experience rate. For use in calculations, the progress ratio is introduced, which is defined as unity minus learning rate.

$$c_x = c_0 \left(\frac{P_x}{P_0} \right)^{\frac{\log progress\ ratio}{\log 2}} \qquad \text{(Eq. 2.1)}$$

$$P_x = \sum_{t=0}^{T} P_t \qquad \text{(Eq. 2.2)}$$

$$P_t = P_{t-1} \cdot (1 + GR_t) \quad \text{for} \quad t \geq 1 \qquad \text{(Eq. 2.3)}$$

$$P_x = P_0 \cdot \prod_{t=0}^{T} (1 + GR_t) \qquad \text{(Eq. 2.4)}$$

Equation 2: Empirical law of experience curves. Abbreviations stand for: cost at historically cumulated output level of P_x (c_x), cost at initial output level P_0 (c_0), historically cumulated output level (P_x), initial output level (P_0), unity minus learning rate defined as (*progress ratio*), annual production of a specific year (P_t), and growth rate of a specific year (GR_t). Eq. 2.2 and 2.4 are equivalent. In this work the variables *Capex* and c_x are identical and describe the specific investment cost in a PV system in cost/Wp. Combination of Eqs. 2.1 and 2.4 effectively transforms the cost function from production volume dependence to time dependence, which is often more convenient for scenario analyses.

The empirical law of experience curves (Eq. 2.1) drives the levelized cost of electricity of PV systems (Eq. 1.1) which has to compete against local electricity prices in respective markets. Electricity prices differ strongly in different markets and even for different players in the same market segment as a consequence of market forces.

Nevertheless, average electricity prices can be derived for market segments. In general, electricity prices are a function of fuel cost, capital cost, labour cost, grid cost, energy taxes, energy subsidies, greenhouse gas (GHG) emission cost and profit margins of generation, transmission and distribution companies. PV grid-parity is defined as the intersection of LCOE of PV and local electricity price in time.

The model is based on the effective average PV system price in Germany in 2010 of 2.70 €/Wp and 2.40 €/Wp for residential roof-top systems and industrial large-scale roof and accordingly PV power plants, respectively. These market segments take over a global price setting function due to the sheer size of the German market.[1] System price assumptions are based on consensus view of several financial PV industry analysts all published in 2010.[27-33] The empirical observed experience curve (Eq. 2.1 and Figure 3) correctly describes the cost reduction of PV systems for the last 30 to 40 years. Over the last three decades the learning rate of PV has been on a stable 20% level. Mature industries show a flattening of experience curves, therefore the decrease of LOCE for PV was calculated by a progress ratio of 0.80 and 0.85 as well, i.e. a learning rate of 20% and 15%, respectively. Cost reductions are indirectly driven by PV industry growth, which was set to 30% for the entire scenario period from 2010 to 2020. The annual growth rate was in average 45% for the last 15 years (Figure 1) but consensus expectation of PV installation growth rate is about 30% (section 3.2). We might underestimate the cost reduction in time in case of continued growth at the rate of the last 15 years.

Concerning electricity prices, initial market sizes for the year 2010 and average annual market growth rates of the market segments in the different regions are taken from various sources [34-40] and prices are assumed to increase in the same manner as in the last years by 5%, 3% and 1% per year for electricity price levels of 0 – 0.15 €kWh, 0.15 – 0.30 €/kWh and more than 0.30 €/kWh, respectively.

Further assumptions for important parameters are taken into account. PV system performance ratio is assumed to constantly increase for residential and industrial systems from 75 and 78% in 2010 to 80 and 82% in 2015, respectively, and remain constant afterwards. Weighted average cost of capital is set to 6.4%, as in several markets PV investments start at about 5% average cost of capital. Annual PV operation and maintenance expenditures (Opex) are estimated to be 1.5% of initial PV system investments (Capex). PV system lifetime is assumed to steadily increase from 25 years in 2010 to 30 years in 2015 and stay constant afterwards. Solar irradiation on modules at optimal fixed-tilted angle for each location (Figure 2) [23] is averaged by population distribution for respective countries and aggregated regions. Data and method is described in detail elsewhere.[41]

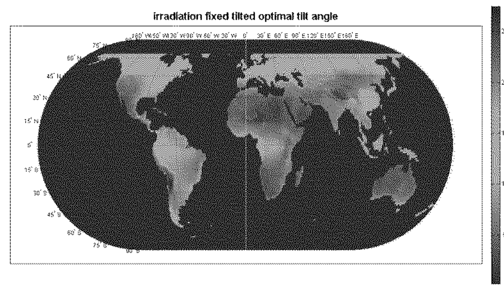

Figure 2: Annual irradiation on module surface of fixed tilted PV systems at optimal tilt angle for optimised irradiation. Every coordinate of a 1°x1° mesh within 65°S and 65°N is separately optimised for maximum annual irradiation on module surface. Hay-Davies-Klucher-Reindl model is applied by calculating each month of the year and selecting the tilt angle of maximum annual irradiation.[23]

The dynamic grid-parity model enables estimates where and when sustainable market segments are created by implementing PV electricity generation. Scenario assessment has been applied for the years 2010 to 2020.

Major assumptions and respective key driving forces of the dynamic grid-parity model are the experience curve approach, PV industry growth, PV system cost and electricity prices. Due to their enormous impact on the analysis these key driving forces are discussed in detail in section 3.

3 KEY DRIVING FORCES OF GRID-PARITY ANALYSIS

In the following subsections the five key driving forces of grid-parity analysis are discussed in detail to give a more founded basis for the assumptions applied. The intention of the authors is to give more transparency to the applied scenario and its conservative parameter setting.

3.1 EXPERIENCE CURVE APPROACH AND PV SYSTEM COST

Analyses of technological change have identified patterns in the ways that technologies are invented, improved and diffuse into society. Studies have described the complex nature of the innovation process in which uncertainty is inherent, knowledge flows across sectors are important, and lags can be long. Perhaps because of characteristics such as these, theoretical work on innovation provides only a limited set of methods with which to predict changes in technology. The learning or experience curve model offers an exception.[24]

The learning curve originates from observations that workers in manufacturing plants become more efficient as they produce more units. In its original conception, the learning curve referred to the changes in the productivity of labour which were enabled by the experience of cumulative production within a manufacturing plant. The experience curve approach was further developed to provide a more general formulation of the concept, including not just labour but all manufacturing costs and aggregating entire industries rather than single plants.[24] A good overview on experience curves in general and PV in particular is given by Nemet [24] and Swanson [42]. Consensus results of different studies on learning rates in PV industry led to a well accepted learning rate of 20% (Figure 3), hence a progress ratio of 0.80.[43-]

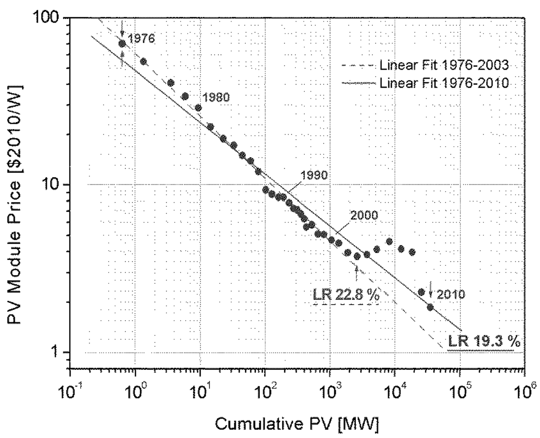

Figure 3: Learning curve for PV modules for the years 1976 - 2010. Long-term cost trend of reducing PV module cost by 20% per doubling of cumulated historic production has been stable for the entire period. Oscillations around this trend are mainly caused by varying PV industry market dynamics and therefore profit margins, documented by applying different learning rates of 22.8 and 19.3% for the periods 1976 – 2003 and 1976 – 2010, respectively. Figure and underlying trends are discussed in more detail elsewhere.[18]

Historically, no energy technology showed such a high learning rate over such a long period of time.[43,44] Renewable energy technologies typically exhibit learning rates of about 10%, e.g. wind power and solar thermal power plants (STEGs).[43,45]

PV learning curve characteristics are well documented for all value chain steps from metallurgical silicon (Si) or other semiconductor ores to PV modules. A few works also describe inverters, systems and the most relevant metric cost per generated energy [43,46,47,24]. They confirm for entire PV systems a learning rate of 20 % and an even higher learning rate for cost per energy, induced by increasing overall system efficiency. Even higher learning rates have been recorded for similar technologies: as a long-term trend for DRAM memory chips and flat panel displays learning rates of 40 and 35%, respectively.[48] Comparison to solar PV is quite interesting due to the fact that both technologies are semiconductor based, just as PV is, but DRAMs getting lower in cost by increasing integration density of transistors while displays reduce cost by increasing production area. Former cost reduction strategy is not possible for PV, except for high concentrating PV, whereas generating scaling effects by increasing area might also be a valuable pathway for further cost reductions and have already been applied in last decades [24]. Fundamental differences in cost structures of displays and PV systems should be better analysed due to a twofold higher learning rate for displays than for PV.

In many industries it was observed that as a function of cumulated production the learning rates declined and showed a more flattening characteristic which is a consequence of ultimate floor cost of a fully optimized product.[49] Nevertheless, until now this has not been observed in PV industry. Authors not fully aware of current and future potentials of PV cost structure usually assume much too high PV floor cost, i.e. lowest future possible cost for PV technology, e.g. recently published PV system floor cost assumption of 2.1 €/Wp for the year 2100.[50] Even today reality has already reached lower levels and cost might decline drastically in the decades to come. Leading PV experts estimate the achievable long-term cost potential for PV module technology and respective industry below 0.30 USD/Wp[51] and Pietzcker et al expect PV system floor cost, i.e. long-term cost level, of 0.60 USD/Wp[[52] Currently, lowest manufacturing cost of PV modules are 0.74 USD/Wp and are achieved by cadmium telluride (CdTe) PV company First Solar.[53] Lowest possible today's PV power plant system costs are about 1.5 – 1.6 €/Wp, including all manufacturing, sales, general administration and research cost, excluding cost for debt, equity and value chain inefficiencies, which can be achieved for both CdTe PV and crystalline silicon PV technology.[54]

3.2 GROWTH RATE OF PV INDUSTRY

Growth rates of worldwide PV installations have been on a constant high level of 45% in the last 15 years (Figure 1). Compared to industries of similar preconditions growth rates of worldwide PV installations are outstanding. Benchmarking industries are for example wind power, mobile phones and crude oil. In the end all these three industries offer commodity like products, due to its standardization and modularity. In particular, wind power and mobile phones show this modular characteristic. Modularity and scalability might be one of the greatest advantages of PV, as solar cells can be used for both a 10 Wp solar home system and a multi hundred MWp PV power plant. Growth rates for PV sales have been outstandingly high for more than one decade. This phenomenon is discussed in more detail elsewhere.[5]

There are tremendous needs to establish a sustainable energy industry as 80% of global energy market is structural not sustainable, either due to diminishing resources (crude oil, natural gas, uranium), climate change restrictions (coal, crude oil, natural gas) or severe lasting security problems (nuclear power).[21,55-61]. Need for a sustainable energy supply is greater than ever in human history.

Structural characteristics of renewable energy technologies fit well to fundamental requirements of energy technologies in the 21st century: low greenhouse gas (GHG) emissions, high energy yield factors for a fast substitution of today's not sustainable technologies, i.e. short energy payback times (EPBT), and pathways to reach a sustainable low cost level. PV well fulfils these requirements: GHG emissions are between 15 – 45 gCO_{2eq}/kWh [62-65], energy yield factors are between 10 – 30 due to a EPBT of 0.8 to 2.5 years [62-65] and fast declining LCOE (section 3.1 and 4).

Remarkably, fundamental growth limits are still outstandingly far away for PV embedded in respective local and global electricity systems. For PV it will take a long time to reach these limits which are estimated to be at least between 1,500 and 12,000 GWp total installed capacity within the next four decades and depending on economically available storage solutions and global wealth convergence.[18] There are several studies outlining technologically and economically feasible pathways for a PV share in local, nationwide, continental and even global electricity systems of 25 up to 100%.[66-72] One of the authors of this paper was involved in an estimate of overall energy supply potential of solar power [72], which was calculated for solar thermal electricity power generation (STEG), but due to nearly identical overall land use efficiencies it can be transferred to PV and by applying the storage assumptions of Denholm and Margolis [68] and Zweibel et al. [66] it would be possible to entirely transfer the outcome to PV.

Growth rates of PV seem not to be limited for at least the next one to two decades. The assumption in this paper of an average annual 30% growth rate of PV industry in the scenario period of 2010 to 2020 is considered to be very conservative. Annual growth trend for the last 15 years has been 45% (Figure 1). Nevertheless, consensus of scientific researchers and financial analysts is a growth rate of about 30%.[1,73,28,29,31,74-76] However, it has been very common to underestimate both near and long-term growth rates of PV.[77]

3.3 PV SYSTEM PERFORMANCE

The key performance index of PV is LCOE and therefore improvements in lifetime, performance ratio and yield (kWh/kWp), e.g. better temperature coefficients and better low light performance, will increase the yield and therefore decrease the LCOE. There are indications that PV module lifetime is longer than the assumed 25 years [78] which will further improve LCOE. Better performance and longer lifetimes of key components will improve the performance ratio and lower operation and maintenance, hence improve LCOE.

3.4 ELECTRICITY PRICES

Real electricity price escalation for residential market segments has been on average 4.3% p.a. in the years 2000 to 2007 in the EU [34] and on average 3.6% p.a. in the years 2000 to 2006 in the US [35]. Cost trends in other regions in the world are dependent on local electricity subsidies or taxes, vulnerability to oil and natural gas price volatility, increase in environmental standards and stranded power plant investments.

In liberalized electricity markets, like in the EU and the US, electricity prices are coupled to respective electricity wholesale prices. These wholesale prices are typically a function of available supply and demand and are dependent on the last class of power plants which is needed to cover supply (merit-order). Therefore, the cost structure of natural gas (NG) power plants strongly influences wholesale prices. The cost structure of NG power plants itself is dominated by NG fuel cost. It has been observed for the last three decades that NG prices are strongly correlated to crude oil prices [21], thus in the end the global crude oil price determines end-users electricity prices in liberalized electricity markets. Probability is high that historical peak-oil occurs in the years till 2015 which will be accompanied by high crude oil prices [55-57] and consequently high electricity prices. Regulated markets in the world also face increasing electricity cost due to rising fuel prices.

Global electricity supply is dominated by coal, NG, hydro-electric, nuclear and oil power plants, which generate 40.9, 20.1, 16.4, 14.7 and 5.7% of electricity.[86] All other sources, in particular renewable energy sources, still contribute to a minor fraction.

Social cost of climate change mitigation will have to be internalized in energy cost for having real price signals of energy use.[59] Conservative estimates clearly show that social cost of climate change are in the order of 70 €/tCO_2.[59] Electricity prices outside the EU reflect no CO_2 cost and respective prices in the EU started to internalize GHG emissions in the mid 2000s, but on a subcritical low level of 10 – 25 €/tCO_2. Maybe marginal cost of GHG emissions to tackle climate change will be even higher than 70 €/tCO_2. Regions dependent on fossil fuel fired power plants, in particular coal, will be affected by high escalation rates of true electricity cost.

Other social cost of electricity supply are also not internalised in electricity prices, but have to be paid. Such cost are for instance: higher mortality and multiple illnesses due to heavy metal emissions of coal and oil power plants, military conflicts due to diminishing energy resources, reduced ecological value of destroyed ecosystems by use and exploitation of conventional energy and insecurity due to nuclear proliferation, nuclear terrorism and unclear nuclear waste disposal.

Summing up, the assumption of future electricity price escalation rates is very likely to be conservative.

3.5 ACCESS TO ELECTRICITY

Prerequisite for grid-parity analysis is access to an electricity grid. This is not the case for about 1.5 billion people in the world.[79] Most of them live in rural areas in Sub-Sahara Africa (about 590 million), South Asia (about 610 million) and East Asia (about 195 million). Overview on global access to electricity is depicted in Figure 4.

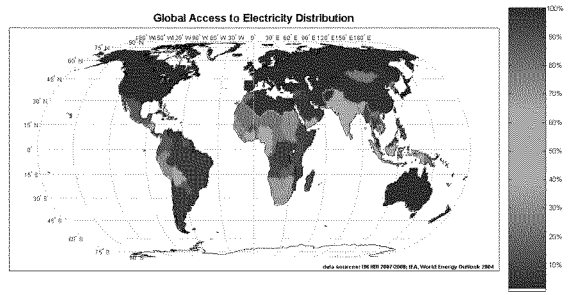

Figure 4: Global access to electricity in percent of local population. Dark blue colour coding represents up to 100% electricity access of local population, whereas dark red is an indication for very low electrification rate of local population of 10% or even less. Data is taken from United Nations Development Programme [80] and International Energy Agency [81].

By far the most people having no access to modern forms of energy live in sunny regions (Figures 2 and 4). Detailed analysis of georeferenced location of world population [82], location of people without access to electricity (Figure 4) and local irradiation on module surface of fixed optimally tilted PV systems (Figure 2) [23] clearly shows excellent solar conditions for most of the 1.5 billion people having no access to electricity (Figure 5).

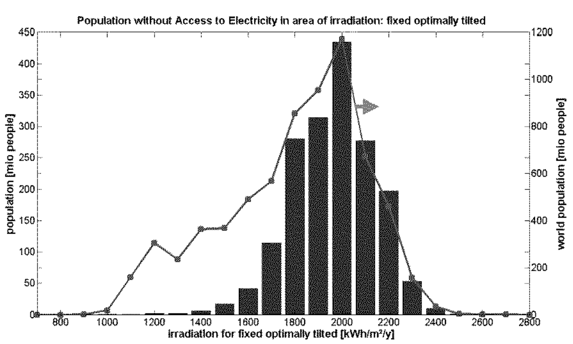

Figure 5: Population without access to electricity in dependence of respective local solar irradiation on module surfaces of fixed optimally tilted PV systems. The line is referred to the right axis and represents distribution of world population. The bars are referred to the left axis and represent population without access to electricity.

However grid-parity concept makes no sense for people without access to electricity, but most of them live in areas of excellent solar conditions, hence highly economic off-grid PV systems are a best adapted and the least cost solution for their energy needs.[12]

4 RESULTS OF GRID-PARITY ANALYSIS

Main result of dynamic grid-parity analysis is a constant market diffusion potential of PV all around the world (Figures 6 – 11).

Starting between 2010 and 2012, the share of all addressable residential electricity market segments increases towards the end of the decade to 86, 99, 28 and 83% in Europe, the Americas, Africa and Asia (Figure 10), corresponding to 1,490, 2,750, 60 and 1,250 TWh, respectively. The same addressable share for all industrial electricity market segments reaches at the end of the decade to 75, 93, 27 and 88% in Europe, the Americas, Africa and Asia at the end of the decade (Figure 11), corresponding to 2,100, 2,110, 90 and 1,750 TWh, respectively.

In Europe grid-parity events of large residential market segments occur first, quickly followed by Asia-Pacific and succeeded by the Americas in the mid of the decade (Figure 10). Most segments in Africa reach grid-parity early in the 2010s, but the largest markets, South Africa and Egypt, heavily subsidize their electricity markets and therefore reach grid-parity only beyond 2020. Grid-parity events of large industrial market segments start between 2011 and 2013 and are synchronous in Europe, the Americas and Asia to a large extent of the entire decade (Figure 8). The characteristics of the industrial segments in Africa are quite similar to the residential ones. As an important remark, it should be pointed out that a flattening of the progress ratio from 0.80 to 0.85 and significantly higher profit margins of PV industry would slow down grid-parity events by one to two years in maximum, as already shown in previews work.[5]

Regions with high solar irradiation and high electricity prices reach grid-parity first, whereas regions with high electricity prices and moderate solar irradiance will quickly follow. LCOE of PV electricity generation in regions of high solar irradiance will decrease from 16 to 6 €ct/kWh in the years 2010 to 2020, respectively.

4.1 EUROPE

Figure 6 depicts grid-parity dynamics in the 2010s for 75 market segments in Europe. First grid-parity market segments are the residential segment in Italy and the residential and industrial segments in Cyprus. This market segments combine best combination for early grid-parity: good solar conditions and high electricity prices. Generally, islands show early grid-parity events all over the world, for which Cyprus is an excellent example. Fundamental reason for this are high electricity generation costs on islands as a consequence of usually oil (diesel) fired power plants, suffering high fuel prices.

Nevertheless, grid-parity can be achieved equally in time via very good solar conditions and moderate electricity prices or moderate solar conditions and high electricity prices. This characteristic can be observed for residential market segments in Portugal and Denmark, respectively. By the mid 2010s about 70% of residential and 30% of industrial market segments in Europe will be beyond grid-parity (Figures 6, 10 and 11). By the end of the 2010s the great majority of all electricity market segments (80% for residential and 75% for industrial) in Europe will be beyond grid-parity. In year 2010 total electricity consumption is about 4,400 TWh. As a consequence of PV capacity factors in Europe and grid restrictions, an overall share of PV electricity in Europe of 6 to 12% in 2020 can be achieved.

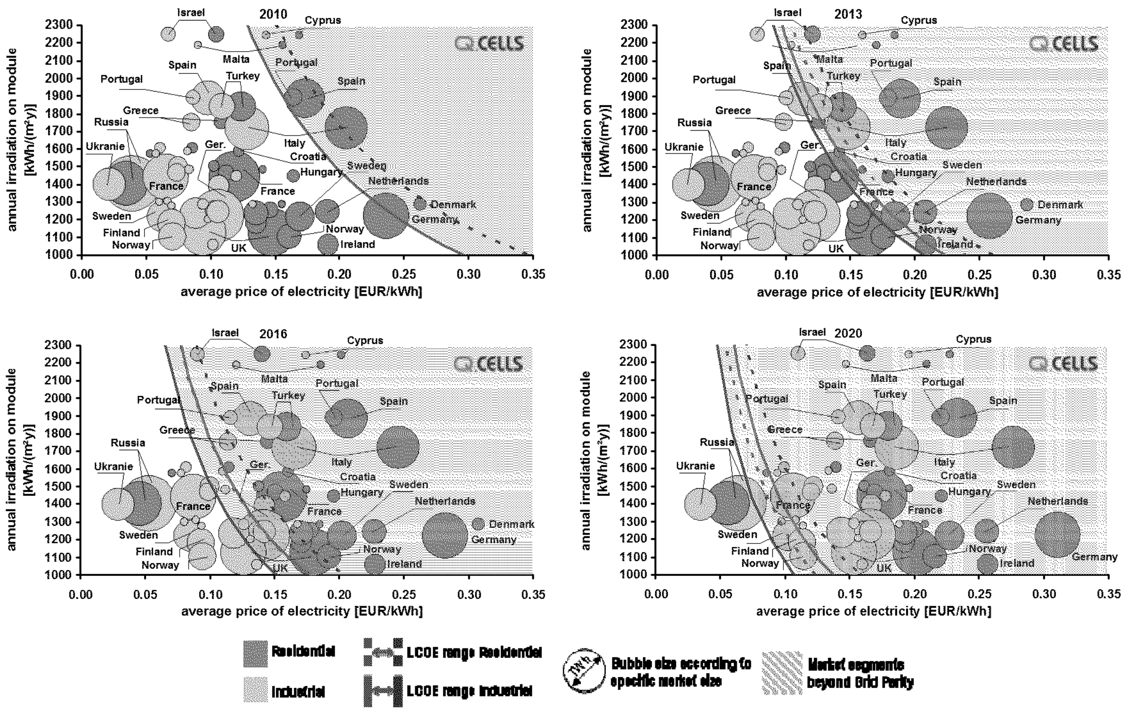

Figure 6: Grid-parity analysis for Europe in 2010 (top left), 2013 (top right), 2016 (bottom left) and 2020 (bottom right). European countries are rated by their population weighted solar irradiation [41] and electricity prices of the major market segments: residential (orange) and industrial (blue). The electricity market volume is indicated by the size of the respective circle. The levelized cost of electricity (LCOE) for PV electricity generation is indicated for smaller residential systems by dashed lines and for larger commercial systems by full lines. Red and green lines represent a normal 20% and conservative 15% learning rate, respectively. Detailed data for depicted countries is given in Appendix Tables 1 – 3.

Clear outcome of grid-parity analysis for Europe is a fast reduction in LCOE of PV and therefore market introduction cost will decline as a consequence. Market deployment of PV is essential for a fast reduction of PV LCOE and hence large contribution of PV to European electricity supply. A significant electricity supply in the EU by PV will help to lower social cost of diminishing fossil fuel resources and GHG emission as discussed in detail in section 3.

4.2 THE AMERICAS

Figure 7 plots grid-parity dynamics in the 2010s for 64 market segments in the Americas. The characteristics of commercial and industrial market segments can be regarded as very similar to those of Europe (section 4.1). First grid-parity market segments are in the Caribbean, consequence of excellent solar conditions and costly oil (diesel) fuel for power supply on islands. Such market segments show best combinations for early grid-parity, as good solar conditions and high electricity prices are given. Nevertheless, grid-parity can be achieved equally in time via very good solar conditions and moderate electricity prices or moderate solar conditions and high electricity prices. This characteristic can be observed for residential market segments in El Salvador and Guyana, respectively. Further examples for last finding would be California and Massachusetts for states of the US.[5]

By the mid 2010s about 30% of residential and 22% of industrial market segments will be beyond grid-parity (Figures 7, 10 and 11). By the end of the 2010s the great majority of all electricity market segments (99% for residential and 93% for industrial) in the Americas will be beyond grid-parity. In 2010 total electricity consumption is about 8,900 TWh. As a consequence of PV capacity factors in the Americas and grid restrictions, an overall share of PV electricity in the Americas of 8 to 16% in 2020 can be achieved.

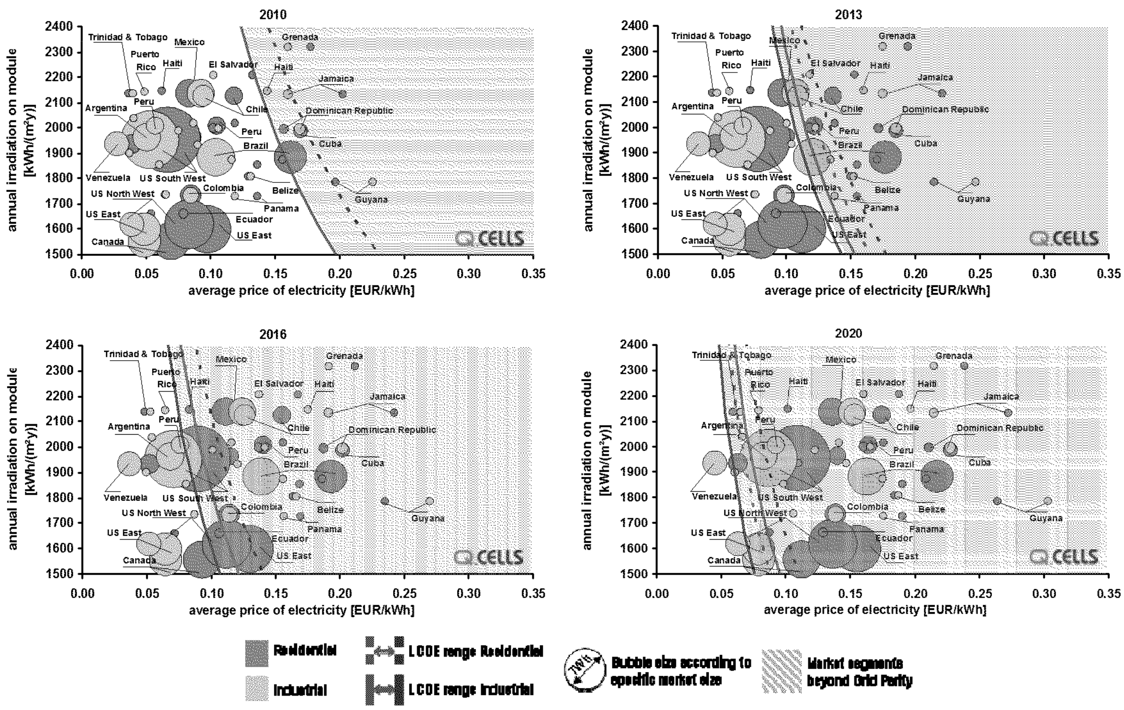

Figure 7: Grid-parity analysis for the Americas in 2010 (top left), 2013 (top right), 2016 (bottom left) and 2020 (bottom right). American countries are rated by their population weighted solar irradiation [41] and electricity prices of the major market segments: residential (orange) and industrial (blue). The electricity market volume is indicated by the size of the respective circle. The levelized cost of electricity (LCOE) for PV electricity generation is indicated for smaller residential systems by dashed lines and for larger commercial systems by full lines. Red and green lines represent a normal 20% and conservative 15% learning rate, respectively. Detailed data for depicted countries is given in Appendix Tables 1 – 3.

An assessment of the outcome for the Americas is quite similar to that of Europe (section 4.1). PV will be also a highly important energy technology for the Americas to tackle depletion of fossil fuel resources and climate change. The faster a broad market introduction of PV is started the faster the highly positive effects of significant PV electricity supply can be realized in the Americas.

4.3 AFRICA

Figure 8 depicts grid-parity dynamics in the 2010s for 81 market segments in Africa. First grid-parity market segments are the residential and mostly industrial segments on the Seychelles and Madagascar and in The Gambia, Burkina Faso, Senegal, Mali and Chad. These market segments show the best combination for early grid-parity: excellent solar conditions and high electricity prices. Similar to Europe and the Americas (section 4.1 and 4.2), islands are among the first grid-parity regions. Several West African countries reach grid-parity early. However, grid-parity should not be overestimated for Sub-Sahara countries, as most people living there do not have access to electricity, particularly in rural areas (section 3.5).[79-81]

Most residential and industrial market segments reach grid-parity in this decade, except South Africa and Egypt (both account together for 64% of total African electricity generation) which heavily subsidize their energy markets with 9 and 15 bnUSD in 2007, respectively.[21] Countries allocate enormous public spending to energy subsidies, e.g. Iran, China, Russia, Saudi-Arabia, India, Venezuela, Indonesia and Ukraine, might enter a vicious circle. In a world faced with rising energy prices (section 3.4) rapidly increasing subsidies are needed for stabilising local prices, whereas only very limited resources are left for investments for inexpensive and price stabilizing renewable energy technologies, like solar PV (section 3.2) and wind power. Energy subsidy induced destabilized national budgets might become an enormous burden for further economic development of those countries.

By the mid 2010s about 8% of residential and 7% of industrial market segments will be beyond grid-parity (Figures 8, 10 and 11). By the end of the 2010s the majority of all electricity market segments (which only account for 28% for residential and 27% for industrial electricity consumption) in Africa will be beyond grid-parity. In 2010 total electricity consumption is about 500 TWh, whereas about 320 TWh are generated in South Africa and Egypt. As a consequence of PV capacity factors in Africa and grid restrictions, an overall share of PV electricity in Africa of 16 to 32% could be achieved by 2020.

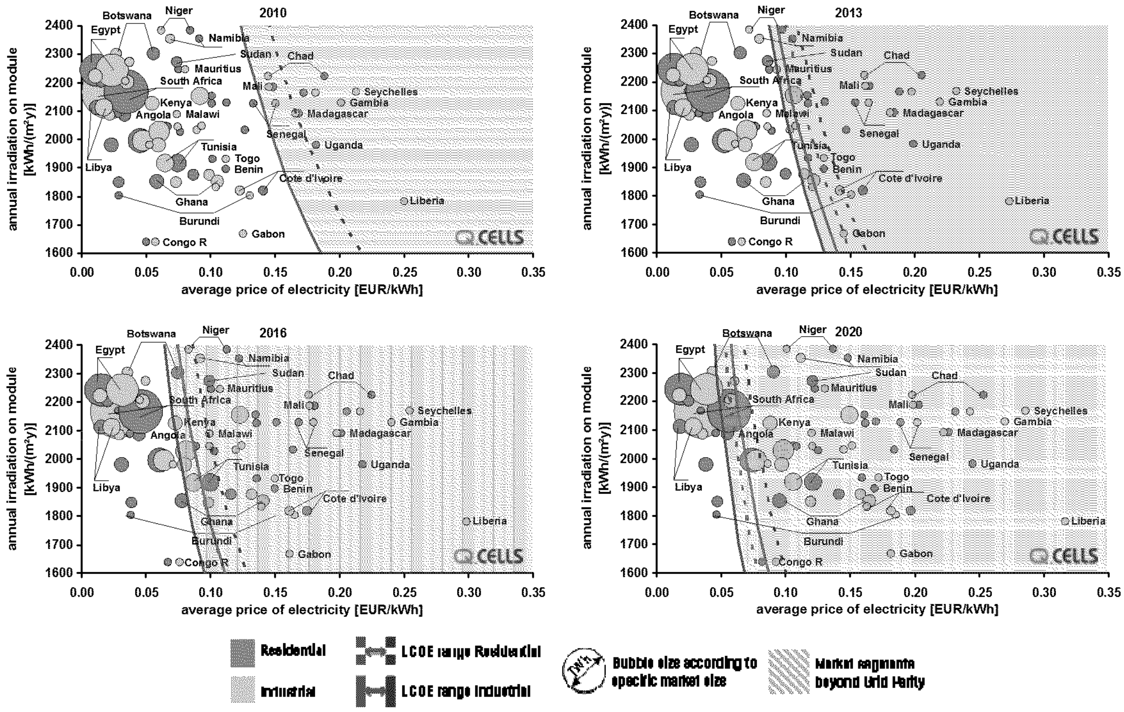

Figure 8: Grid-parity analysis for Africa in 2010 (top left), 2013 (top right), 2016 (bottom left) and 2020 (bottom right). African countries are rated by their population weighted solar irradiation [41] and electricity prices of the major market segments: residential (orange) and industrial (blue). The electricity market volume is indicated by the size of the respective circle. The levelized cost of electricity (LCOE) for PV electricity generation is indicated for smaller residential systems by dashed lines and for larger commercial systems by full lines. Red and green lines represent a normal 20% and conservative 15% learning rate, respectively. Detailed data for depicted countries is given in Appendix Tables 1 – 3.

About 1.5 billion people do not have access to electricity of whom a large fraction live in Africa. The grid-parity concept is not applicable to those people. However, off-grid PV is a very economic option for them due to very low financial amortization periods of two to three years in most rural areas.[12]

4.4 ASIA-PACIFIC

Figure 9 depicts grid-parity dynamics in the 2010s for 85 market segments in Asia-Pacific. First grid-parity market segments are the residential segment in Cambodia, Fiji, Japan and the Philippines and industrial segments in Western China and the Philippines. These market segments show the best combination for early grid-parity: good solar conditions and high electricity prices. Similar to other world regions islands show early grid-parity events.

Nevertheless, grid-parity can be achieved equally in time via very good solar conditions and moderate electricity prices or moderate solar conditions and high electricity prices. This characteristic can be observed for industrial and residential market segments in Western China and Japan, respectively. By the mid 2010s about 45% of residential and 36% of industrial market segments will be beyond grid-parity (Figures 9 - 11). By the end of the 2010s the great majority of all electricity market segments (83% for residential and 88% for industrial) in Asia-Pacific will be beyond grid-parity. In 2010 total electricity consumption is about 8,180 TWh. As a consequence of PV capacity factors in Asia-Pacific and grid restrictions, an overall share of PV electricity in Asia-Pacific of 11 to 22% in 2020 can be achieved.

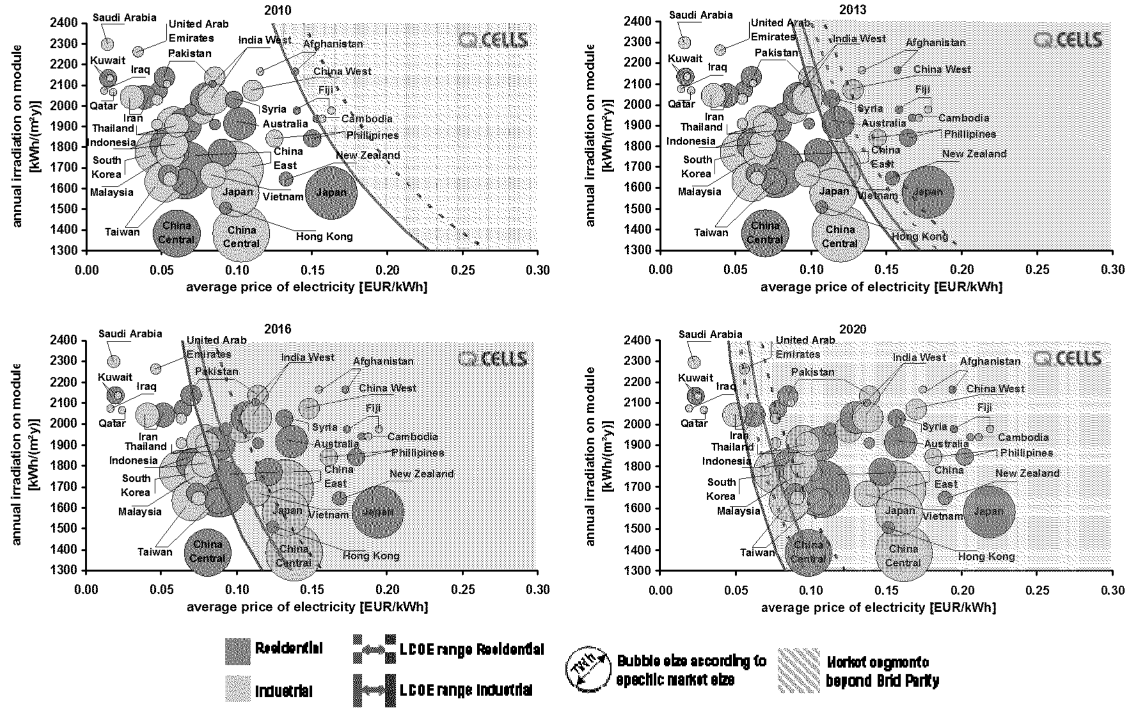

Figure 9: Grid-parity analysis for Asia in 2010 (top left), 2013 (top right), 2016 (bottom left) and 2020 (bottom right). Asian countries are rated by their population weighted solar irradiation [41] and electricity prices of the major market segments: residential (orange) and industrial (blue). The electricity market volume is indicated by the size of the respective circle. The levelized cost of electricity (LCOE) for PV electricity generation is indicated for smaller residential systems by dashed lines and for larger commercial systems by full lines. Red and green lines represent a normal 20% and conservative 15% learning rate, respectively. Detailed data for depicted countries is given in Appendix Tables 1 – 3.

Clear outcome of grid-parity analysis for Asia-Pacific is a fast reduction in LCOE of PV and therefore market introduction cost will decline as a consequence. A significant PV electricity supply in Asia-Pacific will help to lower social cost of current electricity supply, e.g. increasing health cost due to coal related emissions, increasing political insecurity as a consequence of diminishing fossil fuel resources or destabilizing of fragile ecosystems induced by GHG emissions.

Oil producing Asian countries reach grid-parity at the end of the 2010s or even later, which is directly related to very high energy subsidies in these countries.[21] However, high social costs have to be paid, due to very high opportunity cost. For these countries, a much better economic outcome could be realised by shifting opportunity costs into renewable investments, like large-scale solar PV power plants. Currently, historic first fuel-parity events can be observed in Middle East, i.e. generating electricity by burning oil in oil power plants is higher in LCOE than the same amount of electricity in solar PV power plants.[8,15,16] Consequently, enormous local economic benefits could be created by switching from one domestic energy source, fossil fuels, to another: solar photovoltaic energy.

4.5 DEVELOPMENT OVER TIME OF TOTAL ADDRESSABLE GRID-PARITY MARKET SEGMENTS

As shown in the last four subsections a fast market diffusion of PV can be expected all around the world. These fast growing market potentials for PV due to grid-parity events are complemented by highly economic off-grid PV markets in rural areas of developing countries [12] and fuel-parity events which will create highly profitable utility-scale solar PV markets, in particular in sunny oil producing countries and best analysed for MENA region.[8,15,16] In 2008 global electricity generation has been about 19,800 TWh [83] and is expected to increase to about 27,000 TWh by the end of the 2010s. Population weighted mean irradiation on fixed optimally tilted module surface for Europe, the Americas, Africa and Asia is 1,450, 1,890, 2,070 and 1,830, kWh/m²/y, respectively.[41]

Total electricity consumption is about 4,390, 8,940 , 500 and 8,180 TWh in Europe, the Americas, Africa and Asia-Pacific in 2010 and might grow to a global total of about 27,200 TWh in 2020.[83]

The development over time for absolute and relative grid-parity market segments in the world is depicted for residential (Figure 10) and industrial (Figure 11) market segments. Detailed data can be found in Appendix Tables

1 – 3.

First residential grid-parity events occur today in all regions in the world and continue throughout the entire decade (Figure 10). Very early grid-parity showing market segments are Cyprus, Italy, the Caribbean and West Africa. At the end of this decade more than 80 % of market segments in Europe, the Americas and Asia are beyond residential grid-parity. Exception is given for Africa, due to energy subsidies in South Africa and Egypt, which represent more than 60% of electricity generation in Africa. Residential grid-parity is complemented by highly economic off-grid PV in rural regions of developing countries. This is the case for about 1.5 billion people in the world, mostly living in Africa and South Asia.

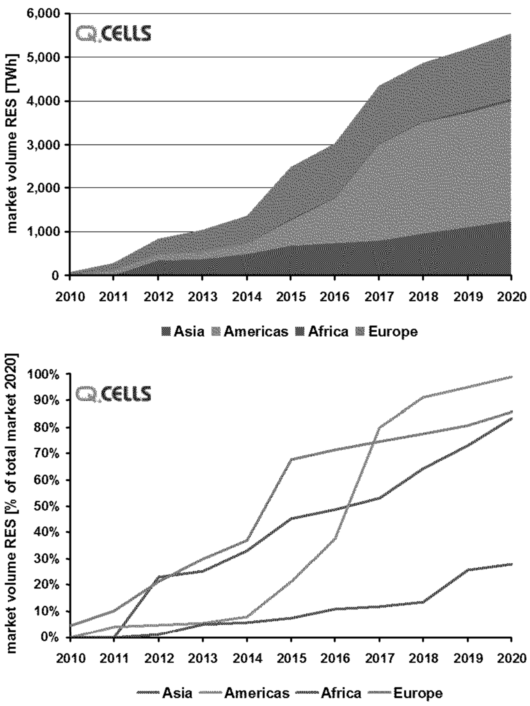

Figure 10: Grid-Parity market volume for residential segments in absolute (top) and relative (bottom) numbers for all regions in the world in the years 2010 to 2020. Detailed data is given in Appendix Tables 1 – 3.

Residential grid-parity analysis (Figures 6 – 10) is performed for 154 countries in the world. These countries account for 98.0% of world population [84], 99.7% of global gross domestic product [85], 99.5% of global electricity consumption [86] and 99.2% of global greenhouse gas emissions [87]. Detailed data is given in Appendix Tables 1 – 3.

First industrial grid-parity events occur today in all regions in the world and often on islands. They continue throughout the entire decade (Figure 11). Very early market segments are Cyprus, West Africa, Seychelles, Caribbean, Cambodia and Fiji. Europe, the Americas and Asia-Pacific show quite similar characteristics of industrial grid-parity events throughout the entire decade. At end of decade more than 75% of market segments in Europe, the Americas and Asia are beyond industrial grid-parity. Exception is given for Africa, due to energy subsidies in South Africa and Egypt. Further exception are mainly oil producing countries used to substantially subsidizing their energy markets, e.g. Russia, Saudi-Arabia, Libya, Venezuela, Iran, Iraq, Kuwait, Qatar, Oman and Angola.

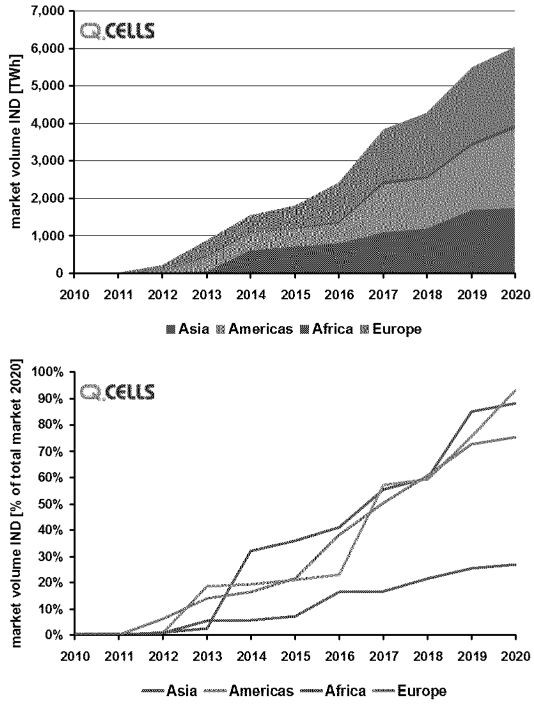

Figure 11: Grid-Parity market volume for industrial segments in absolute (top) and relative (bottom) numbers for all regions in the world in the years 2010 to 2020. Detailed data is given in Appendix Tables 1 – 3.

Nevertheless, significant opportunity cost might become a pressing burden for these countries, as most could substitute substantial amounts of currently burnt oil and natural gas resources by renewable energy sources like solar PV. As consequence of fuel-parity in these countries fast growing utility-scale solar PV power plant markets are very likely. PV power plants can be used as fuel saving technology. Usually, solar PV sceptics claim that PV would be one of the most expensive options for reducing greenhouse gas (GHG) emissions.[88-91] After fuel-parity, PV LCOE are lower in cost than LCOE of oil fired power plants, used as baseload power plants in several countries in the world. As a consequence, reducing GHG emissions by combining oil power plants and PV power plants generates economic GHG reduction benefits. The authors of this publication encourage all readers to be aware of this new fact that might be surprising, in particular for conventional energy economists.

Industrial grid-parity analysis (Figures 6 – 9 and 11) is performed for 151 countries in the world. These countries account for 97.7% of world population [84], 99.3% of global gross domestic product [85], 99.6% of global electricity consumption [86] and 99.1% of global greenhouse gas emissions [87]. Detailed data is given in Appendix Tables 1 – 3.

Key driving force of PV LCOE and therefore for all results presented in this section is system cost. Consensus expectation of financial analysts is 2.70 and 2.40 €/Wp for residential and commercial/ industrial PV systems in Germany in 2010.[27-33] Most parts of PV systems are globally traded and produced to similar world market cost. Furthermore, all PV markets in the world comprising several hundred MWp installations per year will show similar distribution cost. Hence a global average sales price is applicable reflecting similar global PV cost. The most competitive and by far largest PV market is Germany. Therefore German PV prices are used as price benchmark in the world (Figure 12). Experience curve of PV and market growth rates are key factors of ongoing cost reductions of PV systems (section 3.1 and 3.2).

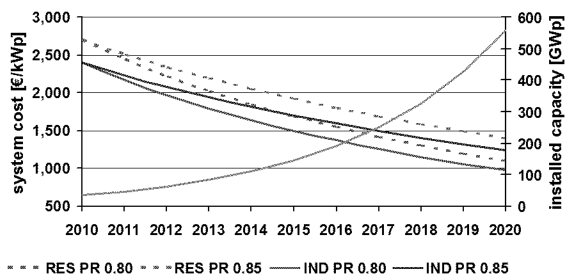

Figure 12: PV system prices in the 2010s assumed for grid-parity analysis. PV system price includes module, inverter, land and all necessary balance of system components. PV system price of 2.70 €/Wp is indicated for smaller residential systems by dashed lines and for larger commercial systems of 2.40 €/Wp by full lines. Red and green lines represent a normal 20% and conservative 15% learning rate, respectively. Growth rate of global PV markets is assumed to be 30% p.a. PV system price is the major contributor to levelized cost of electricity (LCOE). Further assumptions for LCOE are weighted average cost of capital of 6.4%, lifetime of 25 up to 30 years, operation and maintenance cost of 1.5% of PV system price and performance ratio of 75 up to 82%.

Assumptions for underlying PV system cost might be too conservative. Growth rates of global PV installations have been 45% for the past 15 years, which is much higher than expected 30%. Lower future cost potential is also indicated by today's best practice cost for large PV power plants of about 1.5 – 1.6 €/Wp, including all manufacturing, sales, general administration and research cost, excluding cost for debt and equity and value chain inefficiencies, which can be achieved for both CdTe PV and crystalline silicon PV technology.[54] First PV industry players plan to reach fully-loaded PV power plant cost of about 1.20 – 1.35 €/Wp in 2014 [92] (numbers include 0.20 €/Wp additional cost before excluded and an USD/€ exchange rate of 1.4), which is far below expectations in Figure 12 used in this model and provides a further indication of conservative assumption.

For further analysis several parameter combinations of the grid-parity model are given for residential (Table 1) and industrial (Table 2) conditions. Applying all parameter settings, given in section 2, time dependent decrease of capital expenditures (Capex) for new PV installations and respective LCOE can be easily combined. Impact of variations in net PV electricity yield and progress ratio is significant but does not exceed a multiple of 2.5 in the outcome.

year	Capex		E_{net} = 1000 kWh/kWp		E_{net} = 1400 kWh/kWp		E_{net} = 1700 kWh/kWp	
	0.80	0.85	0.80	0.85	0.80	0.85	0.80	0.85
	[€/Wp]		[€/kWh]		[€/kWh]		[€/kWh]	
2010	2.70	2.70	0.277	0.277	0.185	0.185	0.159	0.159
2012	2.22	2.34	0.216	0.228	0.144	0.152	0.124	0.131
2014	1.85	2.05	0.172	0.190	0.115	0.127	0.099	0.109
2016	1.55	1.80	0.141	0.163	0.094	0.109	0.081	0.094
2018	1.30	1.59	0.118	0.143	0.079	0.096	0.068	0.082
2020	1.09	1.40	0.099	0.127	0.066	0.085	0.057	0.073

Table 1: Levelized cost of electricity of residential PV systems in dependence of Capex of PV systems, net PV electricity yield and progress ratio. Calculations are performed according to the assumptions of section 2. PV electricity yield is assumed for the year 2010 and further increase in performance ratio is applied to status of 2010. Net PV electricity yield of 1,000, 1,400 and 1,700 kWh/kWp can be expected in e.g. Czech Republic, Korea and Nepal, respectively. Progress ratio is assumed to be between 0.80 and 0.85.

year	Capex		E_{net} = 1000 kWh/kWp		E_{net} = 1400 kWh/kWp		E_{net} = 1700 kWh/kWp	
	0.80	0.85	0.80	0.85	0.80	0.85	0.80	0.85
	[€/Wp]		[€/kWh]		[€/kWh]		[€/kWh]	
2010	2.40	2.40	0.230	0.230	0.185	0.185	0.136	0.136
2012	1.97	2.08	0.180	0.190	0.129	0.136	0.106	0.112
2014	1.64	1.82	0.144	0.160	0.103	0.114	0.085	0.094
2016	1.37	1.60	0.118	0.138	0.085	0.099	0.069	0.081
2018	1.16	1.41	0.099	0.121	0.071	0.087	0.058	0.072
2020	0.97	1.24	0.083	0.107	0.060	0.076	0.049	0.063

Table 2: Levelized cost of electricity of industrial PV systems in dependence of Capex of PV systems, net PV electricity yield and progress ratio. Calculations are performed according to the assumptions of section 2. PV electricity yield is assumed for the year 2010 and further increase in performance ratio is applied to status of 2010. Net PV electricity yield of 1,000, 1,400 and 1,700 kWh/kWp can be expected in e.g. Germany, Italy and Arizona, respectively. Progress ratio is assumed to be between 0.80 and 0.85.

In regions reaching grid-parity in the early 2010s, e.g. Spain, PV installations will generate a significant benefit for system owners in the following years (Figure 13). New PV solutions, like decentralised storage of PV electricity, might arise due to an enormous financial scope. It might be possible, that the very successful feed-in tariffs in Europe will have to be supplemented by new legal frameworks to further enable a fast diffusion of PV and respective social benefits.

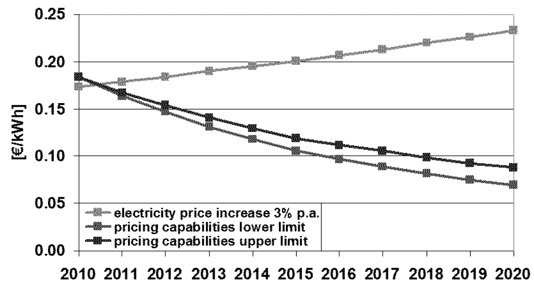

Figure 13: Grid-parity dynamics in Spain – residential segment. Large difference in expected levelized PV cost and electricity supplied by grid may result in stand-alone PV solutions.

Results presented in this section clearly show the enormous potential of PV to become a major source of electricity in the next two decades. Solar energy is available all over the world and distributed more or less homogenously. Based on rapidly improving economics, low technological complexity and excellent resource accessibility solar PV has the potential to become the most democratic source of energy with various beneficial social impacts all over the world.

4.4 OUTLOOK

First of all, it should be noted, that there are already highly economic and therefore sustainable PV markets which will accelerate their growth rates, in particular off-grid PV markets in rural areas in developing countries.[12]

Grid-parity as the third major PV diffusion phase will be observed in the next years in several countries around the world. It poses a question: what will occur beyond grid-parity? Grid-parity events will trigger development of new business models, like PV-storage applications, and will induce progress in electric grid management, like PV induced locally temporarily reversed power flows.

Next parity for PV applications might happen in parallel to grid-parity. As a consequence of high crude oil prices large-scale PV power plants will become a very fast growing market segment due to fuel-parity events occurring right now.[8,15,16] These large PV power plants substitute high priced fossil fuels for fuel saving reasons, hence they will stabilize electricity supply cost in on-grid markets on utility level.

In the years to come, an intensified research, development and demonstration for all fields of PV grid-integration is essential. Systematic R&D is needed on symbiotic relations among renewable energy sources and respective technologies. This might lead for example to hybrid PV-Wind power plants [71] hybrid PV-STEG power plants or PV-Hydro power plants [93]. Key objective should be to achieve the ability to dispatch decentralized PV installations and utility-scale PV power plants on demand, which could include bio methane or even solar methane [94] powered combined cycle power plants, peaking geothermal power plants, hydro-electric pumped storage or other kinds of storage technologies, in particular with regard to arising electric vehicles.

5 CONCLUSIONS

We have presented a model for analyzing grid-parity patterns of PV. A detailed discussion on the key driving forces of grid-parity dynamics, i.e. experience curve approach, PV system cost, growth rate of PV industry, PV system performance, electricity prices and access to electricity, has strongly indicated a more or less conservative parameter setting in the assumptions of the applied scenario for grid-parity in the 2010s. The model has been applied to more than 150 countries in the world accounting for 98.0% of world population and 99.7% of global GDP. Grid-parity events will occur throughout the next decade in the majority of all market segments in the world, starting on islands and regions of good solar conditions and high electricity prices. Cost of PV electricity generation in regions of high solar irradiance will decrease from 16 to 6 €ct/kWh in the years 2010 to 2020.

Besides grid-parity, large commercially addressable PV markets are already available for off-grid PV systems in rural areas in developing countries. True fuel-parity for utility-scale PV power plants starts right now and is very likely to create very large and fast growing commercial PV power plant markets.

Low PV electricity generation cost beyond grid-parity may establish new business models for the PV industry. Furthermore, reaching grid-parity will require new political frameworks for maximizing social benefits.

Finally, it can be stated that PV electricity generation will achieve grid-parity in most market segments in the world and will become a very competitive source of energy.

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APPENDIX

Three Tables are added here:

Appendix Table 1: Residential grid-parity events by year and world region.
Appendix Table 2: Industrial grid-parity events by year and world region.
Appendix Table 3: List of about 161 countries and respective data for grid-parity events, electricity prices, irradiation on fixed optimally tilted module surface, population, gross domestic product, greenhouse gas emissions, electricity generation and electrification rate.

year	Europe	The Americas	Africa	Asia-Pacific
2010	Cyprus, Italy	Grenada, Guyana, Jamaica	Burkina Faso, Chad, Liberia, Madagascar, Uganda	
2011	Denmark, Malta, Portugal, Spain	Brazil, Cuba, Dominican Republic	Mali	Afghanistan, Cambodia
2012	Austria, Germany	Chile, Suriname, Uruguay	Central African Republic, Cote d'Ivoire, Senegal	Fiji, Japan, Palestine (W.Bank/Gaza), Philippines
2013	Belgium, Hungary, Israel, Luxembourg, Netherlands, Turkey	Belize, El Salvador, Nicaragua, Panama, Peru, Puerto Rico	Benin, Gambia, Kenya, Morocco, Namibia	New Zealand
2014	Croatia, Greece, Ireland, Slovakia, Slovenia, Sweden	Guatemala, Mexico	Niger, Rwanda, Togo	Australia, Jordan, Lebanon, Syria
2015	Czech Republic, Finland, France, Norway, Poland, Romania, Switzerland, United Kingdom	Argentina, United States East	Cameroon, Mauritius, Mozambique, Sudan	Bangladesh, Brunei Darussalam, Burma (Myanmar), India West, South Korea
2016	Bulgaria, Latvia	Colombia, Ecuador, Haiti, United States, United States North West	Gabon, Guinea, Tanzania, Tunisia	Hong Kong (China), India East
2017	Estonia, Lithuania	Bolivia, Honduras, United States South West	Botswana	India, Thailand
2018		Canada, Costa Rica, Paraguay	Ghana	China, China East, Malaysia, Pakistan, Sri Lanka, Taiwan
2019	Armenia		Algeria	China West, Indonesia, Vietnam
2020	Belarus, Serbia	Trinidad and Tobago	Congo R, Ethiopia	China Central, Iran, United Arab Emirates
2020+	Moldova, Russian Federation, Ukranie	Venezuela	Angola, Burundi, Congo DR, Egypt, Libya, Malawi, Nigeria, Seychelles, South Africa, Zambia, Zimbabwe	Azerbaijan, Iraq, Kazakhstan, Kuwait, Kyrgyzstan, Lao PDR, Qatar, Saudi Arabia, Tajikistan, Turkmenistan

Appendix Table 1: Residential grid-parity events by year and world region.

year	Europe	The Americas	Africa	Asia-Pacific
2010	Cyprus	Dominican Republic, Grenada, Guyana, Haiti, Jamaica	Burkina Faso, Chad, Gambia, Liberia, Madagascar, Mali, Senegal, Seychelles	Cambodia, Fiji
2011				Afghanistan, Palestine (W.Bank/Gaza)
2012	Italy	Belize, El Salvador, Guatemala, Suriname	Burundi, Cote d'Ivoire, Togo	China West, Philippines
2013	Malta, Turkey	Brazil, Chile, Mexico, Panama	Cameroon, Central African Republic, Gabon, Ghana, Guinea, Mauritius, Morocco, Rwanda	Pakistan
2014	Hungary, Portugal, Spain	Honduras, Nicaragua	Malawi, Namibia	Burma (Myanmar), China, China East, India, India West, Japan, Sri Lanka
2015	Austria, Greece, Israel, Netherlands, Slovakia	Colombia, Cuba	Congo DR, Niger, Tanzania	Brunei Darussalam, China Central, India East, Vietnam

2016	Belgium, Croatia, Czech Republic, Denmark, Germany, Luxembourg, Slovenia	Costa Rica, Peru	Kenya, Mozambique, Nigeria, Tunisia	Thailand
2017	Ireland, Poland, Romania, Switzerland, United Kingdom	Argentina, Puerto Rico, United States South West, Uruguay	Uganda	Australia, Indonesia, Jordan, Lao PDR, Malaysia
2018	Bulgaria, France, Latvia, Lithuania, Serbia	Ecuador	Algeria	Bangladesh, New Zealand, Syria
2019	Estonia, Finland, Norway, Sweden	Bolivia, Trinidad and Tobago, United States East	Congo R, Sudan, Zambia	Azerbaijan, South Korea, Taiwan, United Arab Emirates
2020		Canada, Paraguay, United States	Ethiopia	
2020+	Belarus, Moldova, Russian Federation, Ukranie	United States North West, Venezuela	Angola, Botswana, Egypt, Libya, South Africa, Zimbabwe	Iran, Iraq, Kazakhstan, Kuwait, Kyrgyzstan, Lebanon, Qatar, Saudi Arabia, Tajikistan, Turkmenistan, Uzbekistan

Appendix Table 2: Industrial grid-parity events by year and world region.

Country	**Grid-Parity RES**	**IND**	**Electricity prices 2010 RES**	**IND**	**Irradiation fixed optimally tilted Pop weigh**	**Area weigh**	**max**	**min**	**Popula-tion**	**GDP**	**GHG**	**Electricity total Generation**	**Electrification rate**	
Data source	section 4		[34–40]		[23]				[84]	[85]	[87]	[86]	[80]	[81]
	[year]		[€/kWh]		[kWh/m²/y]				[mio pop]	[bn USD]	[mio t CO_2]	[GWh]	[% of pop]	
Afghanistan	2011	2011	0.139	0.116	2164	2165	2298	1966	29.1	10.2	0.7	n/a	n/a	0.020
Albania			0.000	0.000	1923	1959	2069	1791	3.2	12.3	4.3	5094	n/a	0.995
Algeria	2019	2018	0.046	0.048	1993	2260	2488	1856	35.4	173.9	132.7	35226	n/a	0.985
Angola	2020+	2020+	0.034	0.022	2084	2128	2398	1677	19.0	83.4	10.6	2959	0.150	0.050
Argentina	2015	2017	0.086	0.051	1962	1947	2681	974	40.7	328.4	173.5	115197	0.950	0.950
Armenia	2019		0.056	0.000	1830	1789	1856	1723	3.1	11.9	4.4	5941	n/a	0.995
Australia	2014	2017	0.102	0.058	1914	2215	2570	1429	21.5	1015.2	372.0	251659	1.000	1.000
Austria	2012	2015	0.197	0.106	1389	1395	1476	1324	8.4	416.4	71.8	63505	1.000	1.000
Azerbaijan	2020+	2019	0.020	0.050	1685	1695	1968	1482	8.9	46.3	35.1	23611	n/a	0.995
Bangladesh	2015	2018	0.086	0.047	1908	1907	2022	1820	164.4	79.0	41.6	24334	0.320	0.263
Belarus	2020	2020+	0.067	0.061	1264	1269	1320	1229	9.6	60.3	68.8	31811	n/a	0.995
Belgium	2013	2016	0.194	0.103	1203	1243	1364	1200	10.7	497.6	107.2	85617	1.000	1.000
Belize	2013	2012	0.130	0.132	1807	1893	2094	1757	0.3	1.4	0.8	n/a	n/a	0.870
Benin	2013		0.112	0.000	1895	2008	2135	1809	9.2	6.7	3.1	127	0.220	0.248
Bolivia	2017	2019	0.058	0.041	2037	1983	2690	1625	10.0	16.7	7.0	5293	0.640	0.651
Bosnia			0.000	0.000	1548	1696	2025	1447	3.8	18.5	27.4	13346	n/a	0.995
Botswana	2017	2020+	0.056	0.027	2302	2315	2363	2237	2.0	13.0	4.8	1042	0.390	0.264
Brazil	2011	2013	0.162	0.104	1883	1881	2353	1545	195.4	1612.5	352.5	419337	0.970	0.946
Brunei Darussalam	2015	2015	0.087	0.072	1915	1915	1915	1915	0.4	11.5	5.9	3298	0.990	0.992
Bulgaria	2016	2018	0.086	0.061	1606	1607	1703	1569	7.5	49.9	48.1	45843	n/a	0.995
Burkina Faso	2010	2010	0.172	0.181	2164	2166	2352	2081	16.3	7.9	0.8	n/a	0.070	0.100
Burma (Myanmar)	2015	2014	0.088	0.088	1939	1917	2047	1625	50.5	n/a	10.0	6164	0.110	0.050
Burundi	2020+	2012	0.029	0.131	1803	1803	1803	1803	8.5	1.2	0.2	n/a	n/a	0.235
Cambodia	2011	2010	0.153	0.157	1937	1933	2006	1757	15.1	9.6	4.1	1235	0.200	0.183
Cameroon	2015	2013	0.087	0.099	1875	1889	2157	1580	20.0	23.4	3.6	3954	0.470	0.407
Canada	2018	2020	0.069	0.049	1554	1095	1702	1102	33.9	1400.1	544.7	612594	1.000	1.000
Central African Republic	2012	2013	0.127	0.089	2031	2080	2237	1840	4.5	2.0	0.2	n/a	n/a	0.235
Chad	2010	2010	0.188	0.145	2222	2366	2592	2107	11.5	8.4	0.4	n/a	n/a	0.235
Chile	2012	2013	0.118	0.094	2124	1775	2769	916	17.1	169.5	60.1	57555	0.990	0.970
China	2018	2014	0.064	0.102	1631	1911	2615	1087	1354.7	4344.8	6105.7	2864204	0.990	0.990
China Central	2020	2015	0.061	0.103	1381				315.3					
China East	2018	2014	0.066	0.099	1689				950.7					

China West	2019	2012	0.048	0.111	2071				88.8					
Colombia	2016	2015	0.085	0.085	1732	1725	2454	1375	46.3	242.3	63.4	54301	0.860	0.902
Congo DR	2020+	2015	0.029	0.074	1848	1872	2216	1571	67.8	11.6	2.2	7886	0.060	0.083
Congo R	2020	2019	0.050	0.057	1638	1724	1897	1517	3.8	10.7	1.5	453	0.200	0.196
Costa Rica	2018	2016	0.065	0.065	1735	1899	2222	1537	4.6	29.8	7.9	8698	0.990	0.970
Cote d'Ivoire	2012	2012	0.141	0.123	1818	1891	2100	1708	21.6	23.4	6.9	5530	0.500	0.507
Croatia	2014	2016	0.122	0.082	1586	1652	1906	1490	4.4	69.3	23.7	12430	n/a	0.995
Cuba	2011	2015	0.170	0.076	1987	2198	2386	1950	11.2	n/a	29.6	16469	0.960	0.958
Cyprus	2010	2010	0.169	0.143	2244	2248	2259	2237	0.9	21.3	7.8	4651	n/a	1.000
Czech Republic	2015	2016	0.146	0.103	1251	1259	1293	1197	10.4	216.5	117.0	84361	n/a	0.995
Denmark	2011	2016	0.263	0.095	1287	1240	1378	975	5.5	342.7	54.6	45716	1.000	1.000
Djibouti			0.000	0.000	2318	2318	2318	2318	0.9	0.9	0.5	n/a	n/a	0.235
Dominican Republic	2011	2010	0.157	0.169	1995	2115	2393	1930	10.2	45.8	20.4	14150	0.930	0.923
Ecuador	2016	2018	0.079	0.054	1660	1807	2384	1368	13.8	52.6	31.3	15406	0.900	0.897
Egypt	2020+	2020+	0.012	0.024	2242	2374	2589	1964	84.5	162.8	166.8	115407	0.980	0.977
El Salvador	2013	2012	0.132	0.103	2206	2206	2206	2206	6.2	22.1	6.5	5597	0.800	0.769
Eritrea			0.000	0.000	2215	2239	2389	2049	5.2	1.7	0.6	269	0.200	0.184
Estonia	2017	2019	0.097	0.060	1298	1318	1414	1262	1.3	23.1	17.5	9731	n/a	0.995
Ethiopia	2020	2020	0.038	0.034	2205	2183	2365	1927	85.0	26.5	6.0	3269	0.150	0.026
Fiji	2012	2010	0.140	0.163	1976	2030	2131	1803	0.9	3.5	1.6	n/a	n/a	0.800
Finland	2015	2019	0.135	0.070	1181	849	1394	1167	5.3	271.3	66.7	82304	1.000	1.000
France	2015	2018	0.119	0.065	1441	1521	2065	1239	63.1	2853.1	384.0	574473	1.000	1.000
Gabon	2016	2013	0.086	0.125	1667	1657	1880	1531	1.5	14.4	2.1	1726	0.480	0.479
Gambia	2013	2010	0.113	0.201	2129	2118	2159	2081	1.8	0.8	0.3	n/a	n/a	0.235
Georgia			0.000	0.000	1678	1684	1840	1605	4.2	12.8	5.5	7287	n/a	0.995
Germany	2012	2016	0.236	0.106	1222	1223	1475	1140	82.1	3652.8	805.1	636761	1.000	1.000
Ghana	2018	2013	0.059	0.105	1852	1921	2087	1709	24.3	16.1	9.2	8429	0.490	0.485
Greece	2014	2015	0.108	0.085	1753	1983	2330	1680	11.2	356.8	96.4	60789	1.000	0.995
Grenada	2010	2010	0.178	0.160	2317	2317	2317	2317	0.1	0.6	0.2	n/a	n/a	0.995
Guatemala	2014	2012	0.102	0.106	1997	2061	2355	1778	14.4	39.0	11.8	7916	0.790	0.844
Guinea	2016	2013	0.065	0.093	2046	2063	2139	1953	10.3	4.3	1.4	n/a	n/a	0.800
Guyana	2010	2010	0.197	0.226	1784	1844	1948	1749	0.8	1.2	1.5	n/a	n/a	0.870
Haiti	2016	2010	0.063	0.144	2146	2276	2435	2062	10.2	7.0	1.8	570	0.360	0.335
Honduras	2017	2014	0.068	0.090	1932	1959	2181	1789	7.6	14.1	7.2	5982	0.620	0.601
Hong Kong (China)	2016		0.093	0.000	1506	1605	1703	1506	7.1	215.4	39.0	38616	n/a	1.000
Hungary	2013	2014	0.164	0.120	1445	1448	1500	1339	10.0	154.7	57.6	35859	n/a	0.995
India	2017	2014	0.064	0.079	2032	2027	2446	1615	1214.4	1217.5	1510.4	744078	0.560	0.444
India East	2016	2015	0.069	0.077	1975				338.6					
India West	2015	2014	0.080	0.085	2051				875.8					
Indonesia	2019	2017	0.053	0.059	1809	1916	2415	1616	233.7	514.9	333.7	133108	0.540	0.525
Iran	2020	2020+	0.038	0.031	2041	2121	2459	1569	75.1	385.1	467.0	201029	0.970	0.992
Iraq	2020+	2020+	0.012	0.012	2073	2096	2190	2022	31.5	n/a	92.6	31869	n/a	0.954
Ireland	2014	2017	0.191	0.102	1055	1151	1331	1032	4.6	281.8	43.8	28046	1.000	1.000
Israel	2013	2015	0.105	0.068	2247	2258	2320	2205	7.3	199.5	70.4	51811	0.970	1.000
Italy	2010	2012	0.206	0.129	1720	1855	2186	1568	60.1	2294.7	474.1	314121	1.000	1.000
Jamaica	2010	2010	0.203	0.160	2132	2257	2353	2132	2.7	15.1	12.2	7473	0.870	0.870
Japan	2012	2014	0.163	0.099	1578	1603	1999	1362	127.0	4909.3	1293.4	1100364	1.000	1.000
Jordan	2014	2017	0.084	0.054	2103	2194	2298	2084	6.5	20.0	20.7	11560	1.000	0.955
Kazakhstan	2020+	2020+	0.036	0.024	1709	1704	1954	1508	15.8	132.2	193.5	71653	n/a	0.995
Kenya	2013	2016	0.101	0.054	2124	2117	2313	1929	40.9	34.5	12.2	6477	0.140	0.091
Korea, North (DR)			0.000	0.000	1874	1892	2001	1780	24.0	n/a	79.1	22436	n/a	0.200
Kuwait	2020+	2020+	0.015	0.016	2134	2134	2134	2134	3.1	112.1	86.6	47607	1.000	1.000
Kyrgyzstan	2020+	2020+	0.016	0.016	1840	1880	2007	1698	5.6	4.4	5.6	17082	n/a	0.995
Lao PDR	2020+	2017	0.036	0.057	1829	1827	1949	1656	6.4	5.4	1.4	n/a	n/a	0.800
Latvia	2016	2018	0.105	0.067	1307	1331	1418	1259	2.2	33.8	7.5	4891	n/a	0.995
Lebanon	2014	2020+	0.088	0.022	2159	2262	2334	2159	4.3	28.7	15.3	9287	1.000	0.960

Liberia	2010	2010	0.250	0.250	1781	1788	1915	1696	4.1	0.9	0.8	n/a	n/a	0.235
Libya	2020+	2020+	0.011	0.018	2110	2341	2575	1899	6.6	99.9	55.5	23992	0.970	0.998
Lithuania	2017	2018	0.097	0.070	1277	1286	1381	1218	3.3	47.3	14.2	12482	n/a	0.995
Luxembourg	2013	2016	0.194	0.098					0.5	54.3	11.3	4333	1.000	1.000
Macedonia			0.000	0.000	1718	1713	1774	1636	2.0	9.5	10.9	7006	n/a	0.995
Madagascar	2010	2010	0.169	0.166	2091	2168	2531	1654	20.1	9.0	2.8	n/a	0.150	0.083
Malawi	2020+	2014	0.028	0.074	2088	2103	2176	2041	15.7	4.3	1.0	n/a	0.070	0.058
Malaysia	2018	2017	0.063	0.056	1766	1844	2148	1636	27.9	194.9	187.9	91563	0.980	0.971
Mali	2011	2010	0.148	0.145	2185	2270	2497	2106	13.3	8.7	0.6	n/a	n/a	0.235
Malta	2011	2013	0.156	0.090	2188	2188	2188	2188	0.4	7.4	2.5	2296	n/a	1.000
Mauretania			0.000	0.000	2202	2267	2443	2098	3.4	2.9	1.7	n/a	n/a	0.235
Mauritius	2015	2013	0.075	0.080	2244	2248	2273	2222	1.3	8.7	3.9	n/a	0.940	1.000
Mexico	2014	2013	0.083	0.093	2136	2194	2530	1696	110.6	1086.0	436.2	249648	n/a	0.870
Moldova	2020+	2020+	0.037	0.037	1492	1497	1577	1445	3.6	6.0	7.8	3829	n/a	0.995
Mongolia			0.000	0.000	1910	1996	2333	1701	2.7	5.3	9.4	3649	0.650	0.900
Morocco	2013	2013	0.101	0.092	2153	2194	2410	1938	32.4	86.3	45.3	23192	0.850	0.774
Mozambique	2015	2016	0.077	0.061	2026	2053	2339	1943	23.4	9.7	2.0	14737	0.060	0.087
Namibia	2013	2014	0.091	0.069	2352	2355	2521	1952	2.2	8.6	2.8	1606	0.340	0.347
Nepal			0.000	0.000	2176	2191	2276	2082	29.9	12.6	3.2	2684	0.330	0.259
Netherlands	2013	2015	0.191	0.106	1242	1259	1325	1153	17.0	860.3	175.1	99664	1.000	1.000
New Zealand	2013	2018	0.133	0.056	1644	1644	2017	1309	4.3	130.7	30.5	43519	1.000	1.000
Nicaragua	2013	2014	0.119	0.087	2016	1907	2387	1621	5.8	6.6	4.3	2958	0.690	0.466
Niger	2014	2015	0.084	0.062	2382	2450	2599	2170	15.9	5.4	0.9	n/a	n/a	0.235
Nigeria	2020+	2016	0.023	0.060	1978	2037	2370	1523	158.3	212.1	97.3	23110	0.460	0.449
Norway	2015	2019	0.161	0.071	1103	575	1378	994	4.9	450.0	40.2	121663	1.000	1.000
Oman			0.000	0.000	2239	2336	2511	2167	2.9	35.7	41.4	13585	0.960	0.946
Pakistan	2018	2013	0.052	0.086	2135	2137	2468	1863	184.8	168.3	142.7	98350	0.540	0.530
Palestine	2012	2011	0.125	0.125	2056	2056	2056	2056	4.4	n/a	3.0	n/a	n/a	n/a
Panama	2013	2013	0.136	0.119	1728	1758	1921	1523	3.5	23.1	6.4	5989	0.850	0.851
Paraguay	2018	2020	0.055	0.037	1898	1891	1930	1850	6.5	16.0	4.0	53784	0.860	0.853
Peru	2013	2016	0.105	0.057	2006	1868	2422	1448	29.5	127.4	38.6	27358	0.720	0.757
Philippines	2012	2012	0.151	0.125	1842	1977	2219	1689	93.6	166.9	68.3	56730	0.810	0.891
Poland	2015	2017	0.136	0.088	1235	1236	1326	1173	38.0	527.0	318.2	161742	n/a	0.995
Portugal	2011	2014	0.164	0.087	1891	1947	2222	1769	10.7	242.7	60.0	49041	1.000	1.000
Puerto Rico	2013	2017	0.097	0.049	2142	2295	2367	2142	4.0	n/a	n/a	n/a	n/a	0.995
Qatar	2020+	2020+	0.018	0.018	2065	2223	2381	2065	1.5	52.7	46.2	15325	0.710	0.956
Romania	2015	2017	0.103	0.075	1500	1492	1625	1364	21.2	200.1	98.5	62697	n/a	0.995
Russian Federation	2020+	2020+	0.034	0.039	1403	993	1998	1012	140.4	1607.8	1564.7	995794	n/a	0.995
Rwanda	2014	2013	0.104	0.104	1831	1819	1854	1783	10.3	4.5	0.8	n/a	n/a	0.235
Saudi Arabia	2020+	2020+	0.014	0.014	2296	2327	2621	2149	26.2	467.6	381.6	179782	0.970	0.984
Senegal	2012	2010	0.133	0.151	2126	2160	2329	2039	12.9	13.2	4.3	2439	0.330	0.314
Serbia	2020	2018	0.053	0.058	1573	1585	1820	1512	10.5	54.6	53.3	36481	n/a	0.995
Seychelles	2020+	2010	0.021	0.213	2168	2168	2168	2168	0.1	0.8	0.7	n/a	n/a	0.800
Sierra Leone			0.000	0.000	1861	1888	1994	1757	5.8	2.0	1.0	n/a	n/a	0.235
Slovakia	2014	2014	0.155	0.133	1286	1296	1363	1240	5.4	95.0	37.5	31418	n/a	1.000
Slovenia	2014	2016	0.141	0.084	1483	1484	1485	1482	2.0	54.6	15.2	15115	n/a	1.000
Somalia			0.000	0.000	2100	2188	2538	1970	9.4	n/a	0.2	n/a	n/a	0.070
South Africa	2020+	2020+	0.035	0.021	2166	2238	2455	1784	50.5	276.8	414.6	253798	0.700	0.671
South Korea	2015	2019	0.091	0.047	1770	1779	1912	1672	48.5	929.1	475.2	404021	1.000	1.000
Spain	2011	2013	0.173	0.098	1886	1967	2479	1450	45.3	1604.2	352.2	303051	1.000	1.000
Sri Lanka	2018	2014	0.057	0.085	1813	1944	2146	1765	20.4	40.7	11.9	9389	0.660	0.655
Sudan	2015	2019	0.074	0.037	2271	2294	2574	1938	43.2	58.4	10.8	4209	0.300	0.310
Suriname	2012	2012	0.156	0.116	1872	1934	2270	1856	0.5	2.9	2.4	n/a	n/a	0.870
Swaziland			0.000	0.000	1982	1982	1982	1982	1.2	2.6	1.0	n/a	n/a	0.235
Sweden	2014	2019	0.170	0.063	1218	927	1458	1045	9.3	480.0	50.9	143299	1.000	1.000
Switzerland	2015	2017	0.112	0.074	1467	1482	1511	1423	7.6	488.5	41.8	64038	1.000	1.000

Syria	2014	2018	0.098	0.047	2026	2068	2269	1991	22.5	55.2	68.5	37283	0.900	0.866
Taiwan	2018	2019	0.065	0.053	1632	1628	1920	1407	n/a	n/a	n/a	235371	n/a	0.988
Tajikistan	2020+	2020+	0.007	0.007	1996	1987	2238	1777	7.1	5.1	6.4	16924	n/a	0.995
Tanzania	2016	2015	0.067	0.074	2043	2049	2284	1805	45.0	20.5	5.4	2776	0.110	0.092
Thailand	2017	2016	0.066	0.060	1903	1899	2007	1728	68.1	260.7	272.5	138742	0.990	0.911
Togo	2014	2012	0.102	0.112	1931	1991	2079	1849	6.8	2.8	1.2	221	0.170	0.170
Trinidad and Tobago	2020	2019	0.036	0.040	2136	2242	2320	2136	1.3	23.9	33.6	7045	0.990	0.990
Tunisia	2016	2016	0.075	0.065	1916	2062	2306	1819	10.4	40.2	23.1	14122	0.990	0.950
Turkey	2013	2013	0.124	0.109	1839	1883	2274	1520	75.7	794.2	269.5	176299	n/a	0.995
Turkmenistan	2020+	2020+	0.025	0.025	1894	1888	2033	1712	5.2	18.3	44.1	13650	n/a	0.995
Uganda	2010	2017	0.182	0.053	1980	2015	2179	1815	33.8	14.5	2.7	n/a	0.090	0.040
Ukranie	2020+	2020+	0.022	0.022	1398	1424	1697	1259	45.4	180.4	319.2	193381	n/a	0.995
United Arab Emirates	2020	2019	0.035	0.035	2261	2311	2453	2191	4.7	163.3	139.6	66768	0.920	0.974
United Kingdom	2015	2017	0.148	0.095	1128	1153	1456	984	62.3	2660.5	569.0	398478	1.000	1.000
United States	2016	2020+	0.083	0.034	1796	1657	2442	1067	317.8	14204.7	5752.9	4300100	1.000	1.000
United States East	2015	2019	0.097	0.049	1598				176.9					
United States North West	2016	2020+	0.084	0.039	1618				55.9					
United States South West	2017	2017	0.067	0.053	1953				88.0					
Uruguay	2012	2017	0.136	0.060	1853	1860	1915	1778	3.4	32.2	6.9	5619	0.950	0.990
Uzbekistan	2020+	2020+	0.015	0.015	1976	1907	2080	1787	27.8	27.9	115.7	49299	n/a	0.995
Venezuela	2020+	2020+	0.039	0.028	1934	1951	2463	1582	29.0	313.8	171.6	110357	0.990	0.940
Vietnam	2019	2015	0.055	0.084	1665	1744	2054	1387	89.0	90.7	106.1	56494	0.840	0.796
Yemen			0.000	0.000	2295	2375	2525	2162	24.3	26.6	21.2	5337	0.360	0.503
Zambia	2020+	2019	0.015	0.035	2201	2214	2315	2114	13.3	14.3	2.5	9385	0.190	0.184
Zimbabwe	2020+	2020+	0.011	0.011	2221	2220	2331	2072	12.6	3.4	11.1	9776	0.340	0.409
World					1846	1776	2769	772	6883.1	59557	28313	18913638		

Appendix Table 3: List of 161 countries and respective data for grid-parity events, electricity prices, irradiation on fixed optimally tilted module surface, population, gross domestic product, greenhouse gas emissions, electricity generation and electrification rate.

ATTACHMENT 12

Lawrence Berkeley National Laboratory

Title:

Learning and cost reductions for generating technologies in the national energy modeling system (NEMS)

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BERKELEY NATIONAL LABORATORY

Learning and Cost Reductions for Generating Technologies in the National Energy Modeling System (NEMS)

Etan Gumerman & Chris Marnay

Environmental Energy Technologies Division

16 January, 2004

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Learning and Cost Reductions for Generating Technologies in the National Energy Modeling System (NEMS)

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Etan Gumerman & Chris Marnay
Ernest Orlando Lawrence Berkeley National Laboratory

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List of Learning Terms

Learning – generally used to mean Technological Learning.

Learning-by-Doing (LBD) – Technological Learning from experience gained from capacity growth.

Learning Rate (LR) – Cost reduction per doubling of installed capacity.

Learning Curve – The shape of the Learning Function.

Learning Factor (LF) – A factor used in the calculation of an electricity generating plants' overnight costs. This value starts at 1.0 and can be reduced every year. It is calculated in two ways and the better or lower value is the one that is used. Method 1 calculates LF as a function of capacity growth, and the second method uses a predefined Minimum Annual Learning.

Learning Function – Also known as Wright's Equation, the relationship between cumulative production and costs.

Minimum Annual Learning (MAL) – Predefined by NEMS, this value is annually subtracted from 1.0 to determine the LF upper bound. For example, if MAL was defined as 0.05 for an 'XYZ' plant, then in year 0, the LF for 'XYZ' would be 1.0, in year 1 the LF would be 0.95, in year 2 LF would be 0.90, and so on. The MAL defined LF is important when the second method of calculating LF, from capacity growth, does not lead to as low an LF.

Technological Learning – the production of goods more efficiently (cheaper or more quickly) due to learning through experience. This paper will distinguish two types of Technological Learning in NEMS, Technological Optimism Learning and Learning-by-Doing.

Technological Optimism – The tendency for unproven designs to have unforeseen costs for the first few units actually built, i.e. cost expectations are always too optimistic. Technological Optimism Factor acts like a pessimistic factor.

Technological Optimism Factor– The actual counterbalancing factor that accounts for the uncertainty due to Technological Optimism by adding a premium to overnight costs.

Technological Optimism Learning – The reduction of the Technological Optimism Factor as installed capacity grows.

Abstract

This report describes how Learning-by-Doing (LBD) is implemented endogenously in the National Energy Modeling System (NEMS) for generating plants. LBD is experiential learning that correlates to a generating technology's capacity growth. The annual amount of Learning-by-Doing affects the annual overnight cost reduction. Currently, there is no straightforward way to integrate and make sense of all the diffuse information related to the endogenous learning calculation in NEMS. This paper organizes the relevant information from the NEMS documentation, source code, input files, and output files, in order to make the model's logic more accessible. The end results are shown in three ways: in a simple spreadsheet containing all the parameters related to endogenous learning; by an algorithm that traces how the parameters lead to cost reductions; and by examples showing how AEO 2004 forecasts the reduction of overnight costs for generating technologies over time.

1. Introduction

The Merriam-Webster dictionary defines the word "learn" as: to gain skill in, by study or experience. This work was motivated in part by an interest in understanding how newer technologies become more cost competitive over time. Technological learning leads to the production of goods more inexpensively. Technological learning as implemented in energy forecasting models describes the combined effect of economies of scale and the process of gaining manufacturing skill from repetition. Cost reductions are especially important for newer technologies, which are frequently limited in their ability to reach the marketplace by high initial costs, and which benefit most rapidly from technological learning.

This paper explains how the National Energy Modeling System (NEMS) incorporates endogenous learning into its cost calculations for power plants. The parameters that affect the magnitude of the learning for each of 21 electric generating technologies are laid out. Learning in NEMS is expressed as a percent reduction of overnight capital costs.

NEMS uses exogenously determined improvements to represent technological learning for demand side end-uses, heat rates, and oil and gas supply. This exogenous learning will not be covered in this paper. However, it should be noted that demand-side and supply-side learning are interactive (Laitner & Sanstad, 2003). Therefore, exogenous learning implemented in NEMS inputs reduces endogenous learning.

NEMS is a partial equilibrium energy economy model that projects supply, demand, new capacity, price of energy, emissions, and other parameters. Its forecast yields the Department of Energy's Annual Energy Outlook (AEO), which is frequently used for energy policy analyses (EIA, 2000).

A major part of this investigation involves figuring out how NEMS calculates cost reductions due to learning for each of 21 power plants types. Technological learning is represented two ways in NEMS, by *Learning-by-Doing* and by *Technological Optimism*. Technological Optimism is more limited and is only applied for the construction of the first 5 plants of any technology type. The total optimism cost reduction is 10% - 15% between the first and fifth units built. Learning-by-Doing, on the other hand, is applied to all incremental installed capacity as an overnight capital cost reduction of between 1% and 10% per cumulative installed capacity doubling.

Section 2 describes the origins of the Learning Function. Section 3 shows the relationship between learning and overnight costs for the electricity generating plant types represented in NEMS. Section 4 explains Technological Optimism. Section 5 details how Learning-by-Doing works and how the Learning Factor is calculated. Section 6 walks the reader through the Learning Factor calculation for a natural gas combined cycle plant as well as showing the calculation for an emerging technology, photovoltaics. Section 7 illustrates how Learning Factors and plant costs change throughout the AEO. Section 8 summarizes which parameters relate to technological learning. Section 9 identifies areas for further research.

2. What is Learning-by-Doing?

T. P. Wright, in 1936, was the first to characterize the relationship between increased productivity and cumulative production. He analyzed man-hours required to assemble successive airplane bodies. He suggested the relationship is a log linear function, since he observed a constant linear reduction in man-hours every time the total number of airplanes assembled was doubled. The reduction in man-hours is called learning-by-doing (LBD). The relationship between number assembled and time to assemble is called Wright's Equation or the learning function (Madsen *et al.* 2002). Wright's Equation, shown below, has been shown to be widely applicable in manufacturing.

Learning Function: $C_N = C_0 * N^b$ where, (1)

N is the cumulative production.
$\mathbf{C_N}$ is the cost to produce $\mathbf{N}^{th}$ unit of capcity.
$\mathbf{C_0}$ is estimated cost to produce the first unit.
b is the Learning Parameter, equal to ln (1-**LR**) / ln (2), where,
LR is the LBD Rate, or the cost reduction per doubling of capacity.

In the technology learning literature the term Progress Ratio is frequently used. It is the complementary value to LR, i.e. 1-LR.

The following hypothetical example, illustrates Wright's Equation. If the first two airplanes took 1000 and 800 hours to assemble respectively, then the LR for airplane assembly could be calculated as 20% and the Progress Ratio would be 80%. Wright's Equation projects future production time if the LR is known. Therefore, the fourth airplane should take 640 hours to assemble and the eighth, 512 hours. This learning curve is shown in Figures 1 and 2, below. These figures are based on the same data, but Figure 2 is plotted on a log scale to illustrate the log linear nature of the learning function.

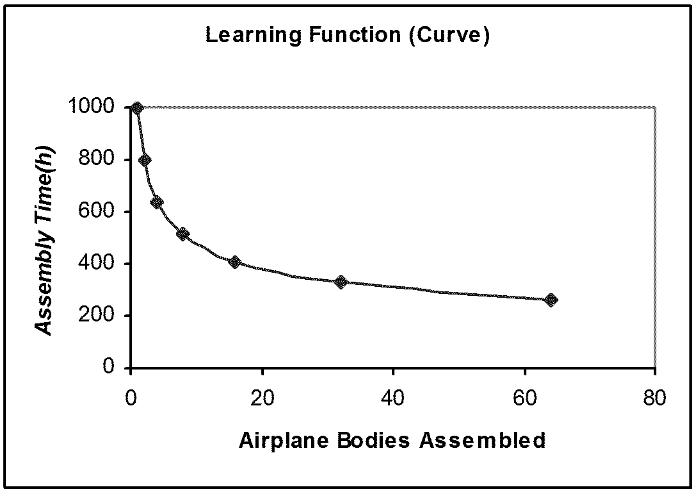


Figure 1. The Shape of the Learning Curve

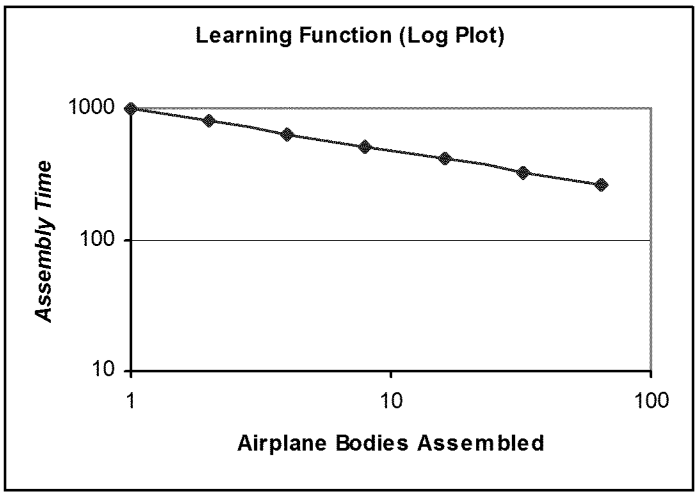


Figure 2. The Shape of Learning Curve on a Log Scale

The learning function described by Wright relates labor input reduction to experience. However, capital cost reductions have also been shown to correlate with experience (Mackay & Probert, 1998). Therefore, the learning function applied to electricity generating technologies in NEMS governs overall initial capital cost reductions not labor reductions.

2.1 Distinct Learning Stages

There is ample evidence from the literature that electricity generating technologies have distinct stages of development that correlate to different LRs. Colpier & Cornland (2002) identified three phases of development with different LRs for natural gas combined cycle plants. Grubler *et al*. (1999) described three stages similar to those used by NEMS. The latter authors identified three classifications to categorize different points in any technological development. *Mature Technologies* are those that have saturated the market, have well-known characteristics, and have limited potential for cost reductions due to learning. *Incremental Technologies* have niche market commercialization and have potential for significant cost reductions due to learning. *Radical Technologies* have almost no market share, and may never reach any significant commercialization, but their potential learning cost reductions are high.

The LRs that Grubler *et al*. (1999) associate with each classification are in Table 1, below. While conceptualizing technological development by three stages is pretty consistent in the literature, the LRs associated with each stage are not. Even the definition of maturity level for certain technologies is subject to interpretation. Unlike Grubler *et al*. (1999), NEMS considers Geothermal an incremental technology and Biomass a radical technology.

Table 1. Learning-by-Doing Rate by Classification

Technology Classification	Learning-by-Doing Rate	Examples: Electricity-Generating Technologies
Mature	0%	Combustion gas turbine, gas combined-cycle, conventional coal
Incremental	10-40%	Biomass, coal combined cycle, nuclear, and wind
Radical	High, potentially > 50%	Geothermal, solar-thermal, and solar PV

Source Grubler *et al*. 1999.

3. Capital Costs for Electric Generating Technologies in NEMS

In NEMS, technology penetration decisions take place in the Electricity Market Module's Electricity Capacity Planning Submodule (ECP). The AEO 2003 version of NEMS characterizes 21 available electric generating technologies. Their total overnight costs for the year 2002 are shown in the first column of Table 2. The total overnight cost for each technology is the product of four components. The four components are: the Initial Engineering Cost, a Technological Optimism Factor, a Project Contingency Factor, and a Learning Factor.

The Technological Optimism and Project Contingency Factors are related to cost uncertainty and can have values above 1.0. Cost reductions over time are driven by the reduction of either of the two components related to technological learning, the Technological Optimism and the Learning Factors. Sections 4 and 5 explain how these factors change. These two factors and the total overnight costs are recalculated and updated for every subsequent year. The first three components in Table 2 are predefined input values for the ECP. However, the optimism factor can be reduced over time.

Table 2. Total Overnight Costs and Cost Components for 2002, in NEMS

	Total Costs (01$/kW)	Initial Engineering Cost Estimates (01$/kW) derived	Technological Optimism Factor in 2002	Project Contingency Factor	Learning Factor in 2002
Scrbd Pulverized Coal	1155	1079	1	1.07	1.0
Integrated Gas CC	1367	1278	1	1.07	1.0
Gas/Oil Steam Turbine	1051	982	1	1.07	1.0
Existing CT	347	330	1	1.05	1.0
Conv CT	409	389	1	1.05	1.0
Adv CT	461	439	1	1.05	1.0
Existing Gas/Oil CC	467	444	1	1.05	1.0
Conv Gas/Oil CC	536	511	1	1.05	1.0
Adv Gas/Oil CC	608	563	1	1.08	1.0
Fuel Cells	2138	1851	1.10	1.05	1.0
Conventional Nuclear	7723	3527	1	2.19	1.0
Biomass (Wood)	1764	1570	1.05	1.07	1.0
Geothermal[a]	1531	1604	1	1.05	1.0
Mun Solid Waste	1461	1365	1	1.07	1.0
Hydroelectric	1046	951	1	1.10	1.0
Pumped Storage	2300	2091	1	1.10	1.0
Wind	1004	938	1	1.07	1.0
Solar Thermal[a]	2622	2450	1.10	1.07	1.0
Photovoltaic[a]	3956	3768	1.10	1.05	1.0
Dist. Gen. Base	804	766	1	1.05	1.0
Dist. Gen. Peak	966	920	1	1.05	1.0

[a] Geothermal, Solar Thermal, and Photovoltaic also receive a 10% capital cost credit.

3.1 Engineering Cost Estimates

The initial engineering cost estimates for overnight costs come from realized costs for more mature technologies. Mature technologies, such as existing combined cycle plants, have known costs. For the youngest technologies, which have no realized costs, EIA uses its analysts' best judgment coupled with engineering cost estimates taken from industry and government experts (EIA, 2002; Personal Communication with James Hewlett, EIA, Nov. 2002).

3.2 Technological Optimism Factor

The *Technological Optimism Factor* (TOF) is a contingency factor applied to the most immature generating technologies. Technologic Optimism is not the typical LBD discussed in the literature, but it is still learning through experience. EIA has identified a tendency for unproven designs to have unforeseen cost overruns for the first few units (EIA, 2002). In order to account for this tendency, the first five units have a TOF applied to the initial engineering estimates. This factor represents rapid learning over the course of the first few units built. The magnitude of this factor is determined by historical data and by econometric estimates originally performed by Ed Merrow at RAND (Personal Communication with James Hewlett, EIA, Nov. 2002). Section 4 explains the Technological Optimism in more detail.

3.3 Project Contingency Factor

The *Project Contingency Factor* (PCF) is a traditional risk factor applied to all technologies, mature or not. The PCF does not change from year to year. Except for nuclear plants, the PCF ranges from a high of 1.10 to a low of 1.05; conventional nuclear plants have a PCF of 2.19. PCF does not relate to learning.

3.4 Learning Factor

The *Learning Factor* (LF) is calculated based on each technology's capacity increase. The LF was explained along with Wright's equation in the previous section. The LF applies to all production and can change every year for every technology. The LF starts at 1.0 in 2002 for all technologies. A detailed explanation of how LFs are calculated follows in Section 5.

4. Technological Optimism Learning

Technological Optimism Learning (TOL), or the reduction of the TOF, is the learning associated with initial commercialization of electric generating plants. It only applies to technologies that are just beginning commercialization. While optimism sounds positive, the TOF is used to raise costs to offset unrealistic optimism.

Technological Optimism (TO) represents the difference between initial new technology cost estimates and actual first-of–a-kind costs by adding a premium to the first five units built of unproven technologies. TOL is the reduction of this premium to 1.0, and after the fifth unit is built, there is no longer any premium associated with TO. Cost reductions associated with TOL are significant but less powerful than the concurrent LBD reductions.

There are only four technologies that are young enough to have TO associated with them: fuel cells, biomass, solar thermal, and photovoltaic plants. The initial TOFs are shown in Table 3. In NEMS, the first plant is considered preexisting for uncommercialized technologies, so the premium applies to the first four plants built, which are plants numbers two through five. The TOFs decrease linearly to 1.0 as units two through five are built.

Table 3. Technological Optimism Factor Applied to Capital Costs when Less than Five of any Revolutionary Type Plants Exist

	Plant Size (MW)	Technological Optimism Factor, 1st plant	2nd plant	3rd plant	4th plant	5th plant
Fuel Cells	10	1.10	1.075	1.05	1.025	1.0
Biomass (Wood)	100	1.05	1.0375	1.025	1.0125	1.0
Solar Thermal	100	1.10	1.075	1.05	1.025	1.0
Photovoltaic	5	1.10	1.075	1.05	1.025	1.0

Source: Data from NEMS AEO 2003 input file *ecpdat* and source code file *ucape*

5. Learning-By-Doing (LBD) and Learning Factor Calculation

LBD in NEMS is the process first described by Wright that accounts for cost reductions due to manufacturing experience. LBD illustrates the relationship between cumulative production (experience) and the cost of the next unit of production. In NEMS, cost reductions are related to cumulative installed capacity, which is a surrogate for experience, and cost reductions are described by percent reduction in capital cost for each doubling of cumulative capacity. Cost reduction per doubling of capacity is based on maturity of the technology or vintage.

Equation (1) solves a technology's current production costs when three parameters are known: overnight costs for the first unit, $\mathbf{C_0}$, cumulative production, **N**, and progress ratio or LBD rate, **LR**. NEMS however, cannot use Equation (1) because the cost data available is for current capacity not for first unit of capacity, $\mathbf{C_0}$. Therefore, the learning function in NEMS takes on a slightly different form than the classic version, making use of current production cost data to calculate current production costs $\mathbf{C_N}$. AEO 2003 has collected data for capacity available in year 2002, **X**, and next unit costs in year 2002, $\mathbf{C_X}$, for each technology. Therefore, NEMS determines $\mathbf{C_N}$, by solving a variation of Equation (1).

$$C_N = C_X * LF_N \qquad \text{where,} \qquad (2)$$

X is the baseline capacity given in the initial year (2002 for AEO 2003).
$\mathbf{C_X}$ is the cost to produce the next unit, when cumulative capacity is **X**.
$\mathbf{LF_N}$ is the Learning-by-Doing Factor for capacity **N**, i.e. the percent reduction of the engineering cost estimates and **LF** is a function of **N**.

If NEMS can calculate the **LF** when production equals **N**, then Equation (2) can be used to solve for $\mathbf{C_N}$. $\mathbf{LF_N}$ can be found by substituting Equation (1), into Equation (2) giving:

$$C_0*N^b = C_0*X^b * LF_N \qquad (3)$$

Then reducing, rearranging, and solving for $\mathbf{LF_N}$ gives,

$$LF_N = N^b \;/\; X^b \qquad \text{or,} \qquad (4)$$

$$LF_N = a* N^b \qquad \text{where,} \qquad (5)$$

a is the parameter equal to $1/\mathbf{X^b}$, as used in NEMS for simplicity.

X and **b** are known constants in NEMS, while **N** is calculated annually. All the **X** and **b** values are explained and shown below in the following two sections.

5.1 Baseline Capacity, 'X'

The determination of Baseline Capacity is confusing as is shown in Table 4. NEMS defines **X** as either the Typical Unit Size or the actual cumulative capacity in 2002. *Typical Unit Size* is the average unit size, defined by NEMS for the purpose of calculating **X** and should not be confused with the increment by which new plants are added in NEMS. The rule is that if the typical unit size is greater than the 2001 cumulative capacity then **X** equals typical unit size. Otherwise, **X** is assigned the actual 2002 cumulative capacity.

Table 4. Vintage & Baseline Capacity, X (all units MW)

A	B	C	D	E	F
PLANT TYPE	Vintage	Typical Unit Size	Cumulative Capacity in 2001	Cumulative Capacity in 2002	'**X**', Baseline Capacity
Scrbd Pulverized Coal	Con.	600	498	498	600
Integrated Gas Comb Cycle	Evo.	550	1,958	2,022	2,022
Gas/Oil Steam Turbine	Con.	300	9,356	11,870	11,870
Existing Combustion Turbine	Con.	160	20,216	41,097	41,097
Conv Combustion Turbine	Con.	160	29,535	50,306	50,306
Adv Combustion Turbine	Evo.	230	299	299	299
Existing Gas/Oil Comb Cycle	Con.	250	20,908	20,908	20,908
Conv Gas/Oil Comb Cycle	Con.	250	39,389	60,045	60,045
Adv Gas/Oil Comb Cycle	Evo.	400	9,958	10,314	10,314
Fuel Cells	Rev.	10	-	-	10
Conventional Nuclear	Con.	1,350	498	4579	1,350
Biomass (Wood)	Rev.	100	9	9	100
Geothermal	Evo.	50	556	567	567
Mun Solid Waste	Con.	30	265	419	419
Hydroelectric	Con.	500	-	-	500
Pumped Storage	Con.	250	-	576	250
Wind	Con.	50	2,306	4,153	4,153
Solar Thermal	Rev.	100	-	1	100
Photovoltaic	Rev.	5	1	10	5
Distributed Generation-Base	Evo.	2	-	-	2
Distributed Generation-Peak	Evo.	1	-	-	1

Note: The definition of Baseline Capacity follows this logic. If Column C is greater than Column D, Column F equals Column C's value. Otherwise Column F equals Column E's value.

5.2 Learning Parameter, 'b' & Vintage

The Learning Parameter, **b**, assumes one of three values depending on what vintage the electric generating technology has been defined. These three vintages, revolutionary (Rev.), evolutionary (Evo.), or conventional (Con.), roughly correspond to three of the stages of technological development described in Grubler *et al.* (1999), Radical, Incremental, and Mature. Vintage by plant type is shown above in Table 4. **b** is defined by its relationship with the **LR**.

$$LR = 2^{b} \quad \text{in other words,} \quad (6)$$

$$b = \ln LR / \ln (2) \quad (7)$$

b can be calculated when **LR** is known.
LR corresponds to vintage. Both values are shown in Table 5, below.

Table 5. NEMS Learning Parameters for Each Technology Classification

Vintage	LR	**b**, Learning Parameter
Revolutionary	10%	-0.152
Evolutionary	5%	-0.074
Conventional	1%	-0.0145

Note: There is one exception to this classification, MSW plants have 0% LR.

Even though a plant's initial vintage is predefined, there is one complication related to vintage. Over time, installed capacity increases and eventually a revolutionary plant can become evolutionary and an evolutionary plant can become a conventional one. Therefore, there must be some point defined when technologies are assumed to pass from one vintage to another.

5.3 Breakpoints

NEMS calls the inflections between vintages, *breakpoints* and these predefine when vintage advances. A revolutionary technology is redefined as an evolutionary technology after three doublings of capacity, i.e. when $\mathbf{N} = \mathbf{X}^* 2^3$. An evolutionary technology is redefined as a conventional technology after five doublings of capacity, i.e. when $\mathbf{N} = \mathbf{X}^* 2^5$. Potentially, even a revolutionary technology could become conventional after eight capacity doublings, i.e. when $\mathbf{N} = \mathbf{X}^* 2^8$.

The AEO 2003 Reference Case forecasts that five plant types will have sufficient installed capacity gains to surpass their breakpoints before 2025. Photovoltaic and Fuel Cell technologies begin as revolutionary and become evolutionary. The two Distributed Generation plant types and the Advanced Combustion Turbine plant type begin as evolutionary and become conventional.

5.4 Cumulative Production and Learning Capacity, 'N'

NEMS differentiates between what it considers cumulative production, **N** for calculating capacity doublings, and total installed capacity. The value of **N** is not necessarily equal to the total installed capacity. Installed capacity growth is calculated annually in the ECP submodule. **N** is related to the installed capacity, but will henceforth be called *Learning Capacity*. There are potentially two adjustments made to actual total installed capacity, in order to calculate **N,** one adjusts higher and one lower. First, NEMS gives learning capacity credit to technologies with international experience. The capacity growth that should count towards international LBD is shown in Table 6. The second adjustment is based on maximum annual learning capacity growth.

5.4.1 International Learning

Manufacturing experience and economies of scale, which lead to learning, are not limited to domestic experience. There are two ways international capacity can impact domestic learning, through technology and people's LBD (Petersik 1997). First, companies that manufacture domestic power plant components may also produce similar components internationally. Second, international experience can lead to industry wide learning. To reflect this interaction, off-shore development is counted, but the amount of international capacity growth that NEMS accepts is limited in two ways. First, only a percent of the total international growth counts based on the extent to which the companies which manufacture, design, operate, and own the plants compete in the U.S. Second, no more than one standard size plant's worth of international capacity per year can count towards domestic learning (Personal communication with Thomas Petersik, EIA, Dec. 2001).

Table 6. International Capacity Growth Applied to Learning

Technology	Adv. Gas/Oil Comb Cycle
Percent Applied to Learning	75%
Year	
2002	475
2003	1425
Total Int'l Capacity	1900

Note: The Percent Applied row indicates what fraction of the International Capacity that counts towards the Learning from capacity growth. For example the 475 MW new capacity of Advanced Combined Cycle in 2002 only counts as 319 MW, (75% of 425) towards learning.

Source: NEMS input file, *eintlrn.*

Table 6 is rather abbreviated because all the other data from the input file is for earlier years. The international capacity file for NEMS was created many AEO versions ago and has not been updated. This component is out of date.

5.4.2 Limits to Learning Capacity, **'N',** Growth year-to-year

EIA feels, justifiably, that there should be an upper limit on LBD in any one year no matter how dramatic the one-year capacity growth may be; therefore, credited growth is limited to 50% beyond the previous year's installed capacity. In other words, when a technology experiences rapid growth, **N** has a maximum increase year-to-year of 50%, but any growth beyond 50% can count towards **N** in the following year.

5.5 Minimum Annual Learning

Equation (4) calculates the LF based on capacity growth for each technology, every year in order to recalculate the cost to build each plant. However, NEMS can reduce total overnight costs every year even if there is no capacity growth and no learning year-to-year because NEMS has built in Minimum Annual Learning (MAL). A minimum LF which constantly decreases each year is calculated differently than the LF from equation (4).

$$LF_2 = 1 - MAL_{vt,yr} \qquad \text{where,} \qquad (8)$$

LF_2 is an alternative LF based on MAL not Learning Capacity growth.
$MAL_{vt,yr}$ based on vintage and year, consult Table 7.

This is not to say that costs are reduced every year. The minimum LF for all years is predefined and correlates to vintage regardless of any or all installed capacity growth. If capacity growth leads to a lower LF than MAL, then the minimum LF is irrelevant. If, however, capacity growth leads to a higher LF than MAL does, the minimum LF is used. as a lower bound. MAL is shown in Table 7 below, and increases in a constant fashion.

Table 7. Minimum Annual Learning by Vintage by Year

	Rev	Evo	Con	Wind[1]
2003	0.87%	0.43%	0.22%	0.04%
2004	1.74%	0.87%	0.43%	0.09%
2005	2.61%	1.30%	0.65%	0.13%
2006	3.48%	1.74%	0.87%	0.17%
2007	4.35%	2.17%	1.09%	0.22%
2008	5.22%	2.61%	1.30%	0.26%
2009	6.09%	3.04%	1.52%	0.30%
2010	6.96%	3.48%	1.74%	0.35%
…	…	…	…	…
2015	11.30%	5.65%	2.83%	0.57%
…	…	…	…	…
2020	15.65%	7.83%	3.91%	0.78%
…	…	…	…	…
2025	20.00%	10.00%	5.00%	1.00%

[1]Wind Plants, though defined as Conventional, have only a 1% Minimum Learning by 2025. Wind plants are treated differently in NEMS because EIA determined that for wind plants learning leads to efficiency improvements rather than cost reductions (conversation with Chris Namovicz, EIA, March 2003).

5.6 Learning Curve by Vintage

TO and LBD both apply for production of the first 4 units built, i.e. units two through five. Therefore, the revolutionary technologies have cost reductions beyond 10% per doubling up to two and a quarter doublings. The shape of the learning curve in NEMS is shown in Figure 3, which has a log-log scale. This figure is an illustration of what the learning curve would look like for a technology that passes through all three stages. Therefore, the cost axis has no units associated with it as the starting point could be at any level. The shape of the curve is what's being pointed out and is consistent no matter the initial cost. The 'y' axis is where a revolutionary vintage technology begins. An Evolutionary Technology begins at the first vertical line, 2^3 or eight units built, and Conventional Technologies begin at the second vertical line, 2^8 or 256 units built.

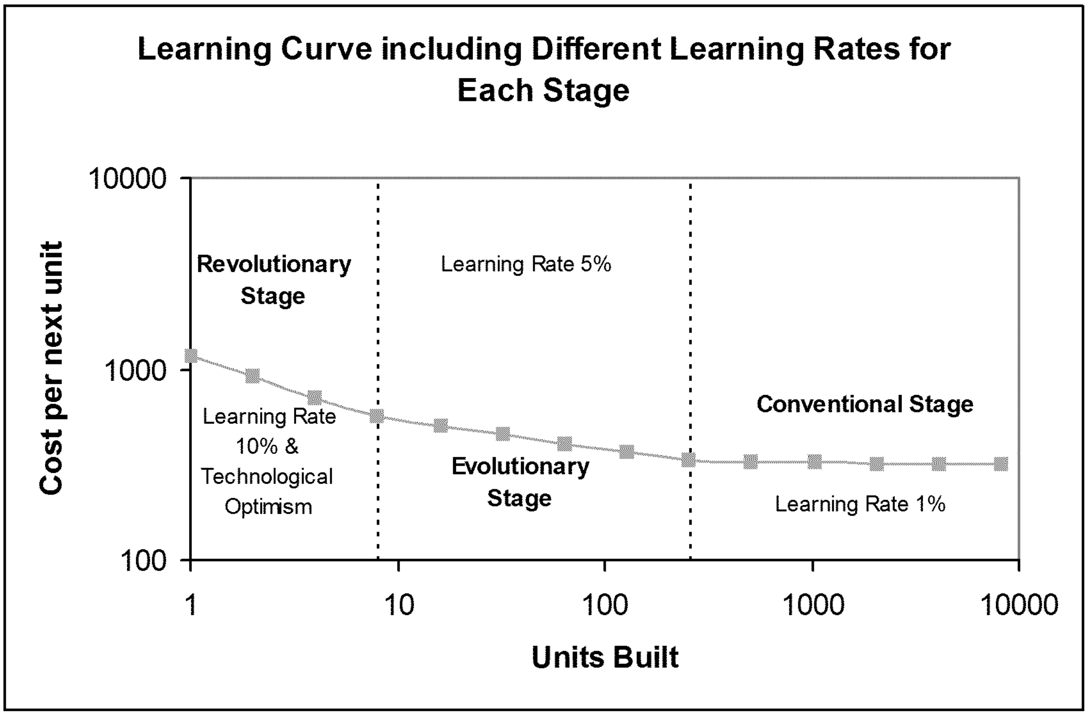


Figure 3. The Shape of NEMS's Learning Curve through each Vintage regardless of Plant Type, (Costs axis values are for scale only)

6. Learning Examples: Advanced Combined Cycle & Photovoltaic plants

In order to verify NEMS's learning calculation, the learning for each technology was calculated for every year and compared to the values calculated by NEMS. The learning factor and most of its related variables are not usually output by NEMS, but the ELOPTLC subroutine can output these variables, which made the verification much easier.

Using initial values for all the relevant variables, a spreadsheet model replicating the ELOPTLC code was written. Once the algorithm and the spreadsheet were set up, it took a little debugging to get the spreadsheet to match the NEMS output. This algorithm is included in the Appendix. A more simplified example of NEMS's learning calculation is shown below in Table 8, for an evolutionary plant, Advanced Gas/Oil Combined Cycle. The calculation of all the relevant variables each year, is included. Subsequently, a revolutionary turned evolutionary plant example, photovoltaic, is shown in Table 9.

This section will explain all steps needed to calculate the Learning Factor in NEMS. Then the reader is walked through the steps for an example Combined Cycle plant.

1. Identify the Baseline Capacity.
2. Identify the vintage of plant.
3. Calculate Learning Parameter, **b**.
4. Calculate **$1/X^b$** term, which is called **a** for simplicity.
5. Identify the annual capacity growth from Electricity Capacity Planning Submodule.
6. Calculate Learning Capacity based on capacity growth.
7. Learning Factor calculated ($a^* N^b$) based on values from #4 and #6 above.
8. Learning Factor calculated based on Minimum Annual Learning, Table 7.
9. Select Learning Factor.
10. Repeat steps 6 - 9 for years 2003 - 2025.

Working through the proceeding steps for an advanced natural gas combined cycle plant results in the following values.

1. 10314 MW from Table 5.
2. Given as Evolutionary.
3. Table 5 indicates that an Evolutionary plant has a **LR** of 5%, and that **b** equals negative 0.074.
4. From #1 and #3 above, **a** is calculated to be 1.981 / MW. NEMS calls this quantity parameter 'a' in order to be able to express the Learning Factor equation (4), more simply as $LF_N = a^* N^b$
5. In 2003 the growth is 1069 MW, subtraction from the spreadsheet below, column $\mathbf{C_{year}}$. (11,383 MW – 10,314 MW).

6. Learning Capacity is equal to the actual capacity 11,383 MW, because 1069 MW is less than 50% of 10,314 MW.
7. $\mathbf{LF_{2003}}$ equals 0.993.
8. Minimal annual learning is 0.43%, Table 7, so the minimum learning factor is 0.996. (1.000 – 0.0043).
9. The lessor of #7 and #8 above, 0.993.
10. These values are shown in the following spreadsheet.
    - -Step 6 is calculated in Column Learning Capacity.
    - -Step 7 is Column LF.
    - -Step 8 is Column minimum LF, and
    - -Step 9 is Column Final LF

Table 8. Learning Factor Calculation for an Advanced Gas/Oil Combined Cycle Plant

Given:		Calculated:	
Vintage	Evolutionary	C_{base}	10314 MW
MAL per year	0.0043	b	-0.0740
Total Capacity	See Table	a	1.981 / MW
Typical Unit Size	400 MW	Learning Factors	See Table

	Total Capacity (MW)	Learning Capacity (MW)	LF (Calculated)	Minimum LF (from MAL)	Final LF
2002	10314	10314	1.000	1.000	**1.000**
2003	11383	11383	0.993	0.996	**0.993**
2004	11383	11383	0.993	0.991	**0.991**
2005	11383	11383	0.993	0.987	**0.987**
2006	14787	14787	0.974	0.983	**0.974**
2007	16965	16965	0.964	0.978	**0.964**
2008	24079	24079	0.939	0.974	**0.939**
2009	29206	29206	0.926	0.970	**0.926**
2010	41641	41641	0.902	0.965	**0.902**
2011	54850	54850	0.884	0.961	**0.884**
2012	69117	69117	0.869	0.957	**0.869**
2013	80512	80512	0.859	0.952	**0.859**
2014	91546	91546	0.851	0.948	**0.851**
2015	103612	103612	0.843	0.943	**0.843**
2016	108751	108751	0.840	0.939	**0.840**
2017	113699	113699	0.837	0.935	**0.837**
2018	120068	120068	0.834	0.930	**0.834**
2019	125661	125661	0.831	0.926	**0.831**
2020	133506	133506	0.827	0.922	**0.827**
2021	138159	138159	0.825	0.917	**0.825**
2022	148877	148877	0.821	0.913	**0.821**
2023	154798	154798	0.818	0.909	**0.818**
2024	167299	167299	0.814	0.904	**0.814**
2025	173197	173197	0.812	0.900	**0.812**

Table 9. Learning Factor Calculation for a Photovoltaic Plant

Given:		Calculated:	
Vintage	Revolutionary	C_{base}	10 MW
Vintage (post 2006)	Evolutionary	b	-0.152
MAL per year	0.0087	b (post 2006)	-0.074
MAL (post 2006)	0.0043	a	1.277 / MW
Total Capacity	See Table	a (post 2006)	0.958 / MW
Typical Unit Size	5 MW	Learning Factors	See Table

	Total Capacity (MW)	Learning Capacity (MW)	LF (Calculated)	Minimum LF (from MAL)	Final LF
2002	10	10	0.903	1.000	**0.903**
2003	14	14	0.857	0.991	**0.857**
2004	22	21	0.806	0.983	**0.806**
2005	29	28	0.768	0.974	**0.768**
2006	37	36	0.740	0.965	**0.740**
2007	47	46	0.721	0.961	**0.721**
2008	60	59	0.708	0.957	**0.708**
2009	70	69	0.700	0.952	**0.700**
2010	83	82	0.691	0.948	**0.691**
2011	95	94	0.684	0.943	**0.684**
2012	110	109	0.677	0.939	**0.677**
2013	125	124	0.670	0.935	**0.670**
2014	140	139	0.665	0.930	**0.665**
2015	158	157	0.659	0.926	**0.659**
2016	175	174	0.654	0.922	**0.654**
2017	193	192	0.649	0.917	**0.649**
2018	210	209	0.645	0.913	**0.645**
2019	228	227	0.641	0.909	**0.641**
2020	245	244	0.638	0.904	**0.638**
2021	263	262	0.634	0.900	**0.634**
2022	280	279	0.631	0.896	**0.631**
2023	298	297	0.629	0.891	**0.629**
2024	315	314	0.626	0.887	**0.626**
2025	333	332	0.623	0.883	**0.623**

Notes:

In 2007, PV is redefined as an Evolutionary vintage since it passes its breakthrough capacity point of 40 MW. Therefore, the MAL, ‘b’, and ‘a’ values are all redefined.

The Total Capacity is higher than the Learning Capacity starting in 2004 because of a minor code inconsistency.

7. Effects of Endogenous Learning in the Annual Energy Outlook Reference Case

The end result of all the learning calculations in NEMS is shown in Table 9. The plants that learn the most are photovoltaic, fuel cells, distributed generation-peak, biomass, and advanced combustion turbine plants. Three of these are revolutionary plants, wherein modest absolute installed capacity growth leads to a significant number of capacity doublings. Many of the 21 plant types only reach their minimum LF. The values in Table 10 that are the minimum LF values have been shaded. The minimum values can be verified by using Equation (8), with the values from Tables 7 & 4 for MAL, year, plant, and vintage.

Table 10. Learning Factors by Plant Type

Plant Type	2005	2010	2015	2020	2025
Scrbd Pulverized Coal	0.99	0.98	0.96	0.94	0.94
Integrated Gas Comb Cycle	0.99	0.97	0.94	0.92	0.90
Gas/Oil Steam Turbine	0.99	0.98	0.97	0.96	0.95
Existing Combustion Turbine	0.99	0.98	0.97	0.96	0.95
Conv Combustion Turbine	0.99	0.98	0.97	0.96	0.95
Adv Combustion Turbine	0.97	0.84	0.77	0.76	0.76
Existing Gas/Oil Comb Cycle	0.99	0.98	0.97	0.96	0.95
Conv Gas/Oil Comb Cycle	0.99	0.98	0.97	0.96	0.95
Adv Gas/Oil Comb Cycle	0.99	0.90	0.84	0.83	0.81
Fuel Cells	0.97	0.73	0.69	0.68	0.68
Conventional Nuclear	0.97	0.95	0.95	0.95	0.95
Biomass (Wood)	0.97	0.93	0.89	0.84	0.75
Geothermal	0.99	0.94	0.92	0.90	0.88
Mun Solid Waste	0.99	0.98	0.97	0.96	0.95
Hydroelectric	0.99	0.98	0.97	0.96	0.95
Pumped Storage	0.97	0.97	0.97	0.96	0.95
Wind	0.99	0.99	0.99	0.99	0.99
Solar Thermal	0.97	0.93	0.89	0.84	0.80
Photovoltaic	0.77	0.69	0.66	0.64	0.62
Distributed Generation-Base	0.99	0.86	0.77	0.77	0.77
Distributed Generation-Peak	0.97	0.84	0.76	0.74	0.72

The total effect over time of technological learning on costs is shown in Table 10. The costs shown in the year 2002 column are identical to those from Table 2. The last column shows the percent cost reduction over the forecast horizon. The percent reduction is identical to the LF for all but six plant types. The cost reductions for the two Distributed Generation plant types are related to both the LF and some learning exogenous to NEMS, which reduces the engineering cost estimates over time. No other technology has predefined cost estimate reductions. The cost reductions for the four revolutionary plants, Fuel Cells, Biomass, Solar Thermal, and Photovoltaic result both from the LF and from the reduced technological optimism factor.

Table 11. Overnight Capital Costs by Plant Type ('01$/kW)

Plant Type	2002	2010	2015	2020	2025	2002 - 2025 % cost reduction
Scrbd Pulverized Coal	1155	1128	1103	1087	1081	6%
Integrated Gas Comb Cycle	1367	1320	1290	1260	1231	10%
Gas/Oil Steam Turbine	1051	1032	1021	1009	998	5%
Existing Combustion Turbine	347	341	337	333	329	5%
Conv Combustion Turbine	409	402	397	393	388	5%
Adv Combustion Turbine	461	389	355	351	348	24%
Existing Gas/Oil Comb Cycle	467	458	453	448	443	5%
Conv Gas/Oil Comb Cycle	536	527	521	515	509	5%
Adv Gas/Oil Comb Cycle	608	548	512	503	493	19%
Fuel Cells	2138	1428	1341	1329	1329	38%
Conventional Nuclear	7723	7316	7305	7299	7299	5%
Biomass (Wood)	1764	1602	1509	1435	1272	28%
Geothermal	1516	1428	1393	1361	1334	12%
Mun Solid Waste	1461	1436	1420	1404	1388	5%
Hydroelectric	1046	1028	1016	1005	994	5%
Pumped Storage	2300	2232	2232	2210	2185	5%
Wind	1004	994	992	990	989	1%
Solar Thermal	2596	2360	2260	2149	2039	21%
Photovoltaic	3917	2462	2346	2270	2220	43%
Distributed Generation-Base[a]	804	692	617	617	617	23%
Distributed Generation-Peak[a]	966	807	737	715	694	28%

[a] Note DG capital costs are reduced over time exogenously.

8. Summary

This paper has tried to lay bare how NEMS comes up with new Electricity Generating plant costs. Engineering Cost Estimates are the starting point for plant costs. Technological Learning is used to forecast cost reductions for all technologies other than distributed generation. The cost reductions usually relate to installed capacity growth though there is built in minimum cost reductions regardless of growth. In AEO 2003 reference case, 2 technologies have no installed capacity growth.

There are six parameters that affect Technological Learning in NEMS.

1. Baseline Capacity, which is the starting point for counting doublings of capacity.
2. Learning Capacity growth year-to-year. Which determines the number of doublings annually.
3. Learning Rate, which affects magnitude of cost reduction per doubling of capacity.
4. Minimum Annual Learning, which reflects a minimum cost reduction regardless of capacity growth.
5. Vintage, there are three classes, each class has its own Learning Rate and Minimum Annual Learning.
6. Technological Optimism Factor, which is a premium added to Engineering Cost Estimates just for the plant types of the youngest Vintage. This raises initial costs for year 2002 beyond Engineering Cost Estimates. Beyond 2002, this factor helps explain cost reductions, as this premium is phased out.

9. Further Research Needs

As with most studies, new questions have arisen during this analysis. There are also areas where the analysis could be improved. Three of the key areas requiring additional research are highlighted below.

1. Do cost reductions from Technological Learning have a significant effect on new installed capacity in NEMS? Policy studies using NEMS frequently are interested in potential fuel switching. Of course cost is only one parameter evaluated by NEMS to determine which technologies are chosen for new installed capacity. LBL-NEMS could evaluate scenarios with more and less technological learning to better determine how concurrent cost reductions affect the forecast for new installed capacity.

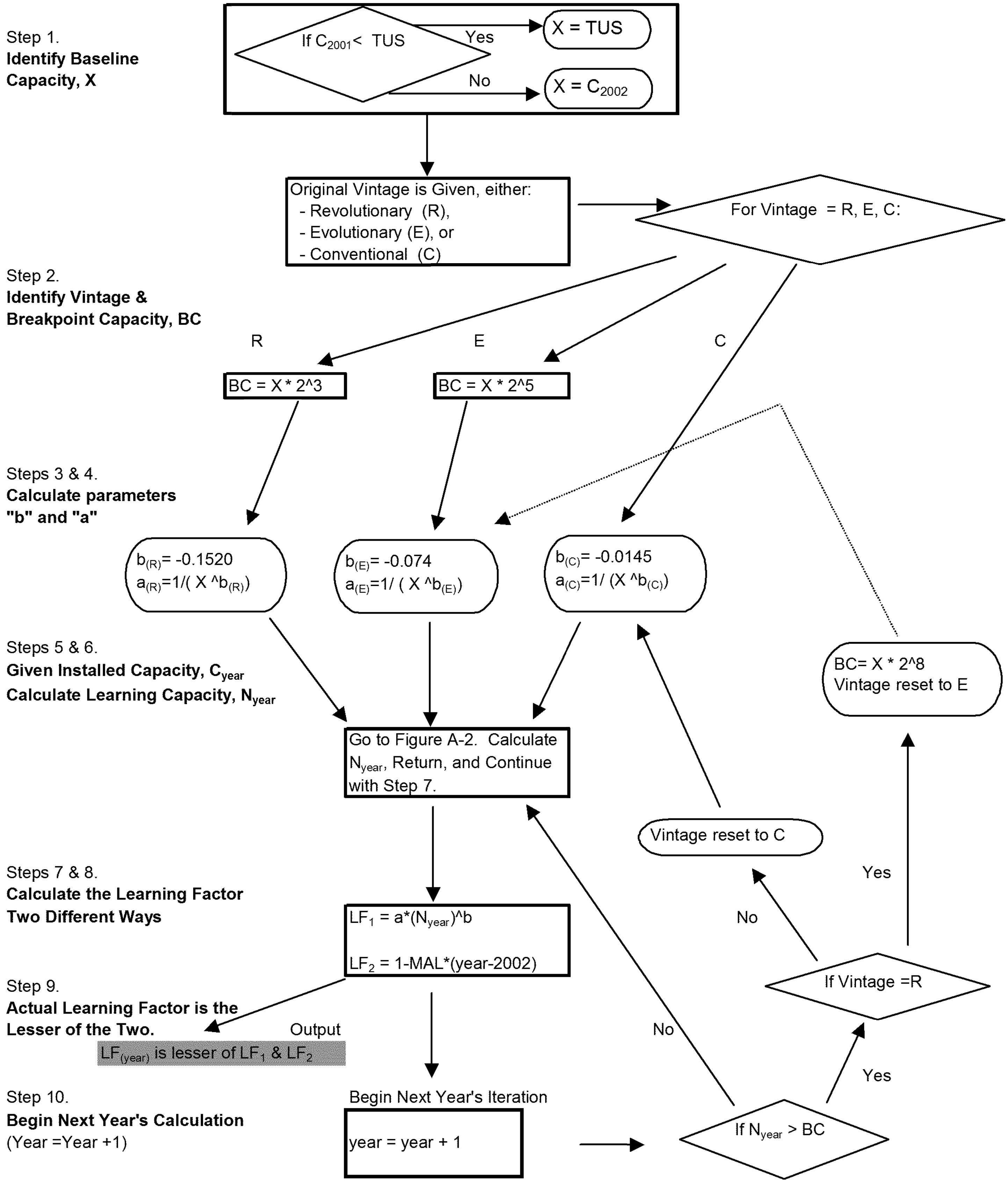
2. Why are the learning rate definitions in NEMS, particularly for Revolutionary and Evolutionary plants, so different than those found in other studies? Many studies (Colpier & Cornland, 2002; Grubler *et al.* 1999; Neij, 1997; Mackay and Probert, 1998), suggest learning rates between 10% and 30% per capacity doubling for mass-produced technologies. The literature seems to show a wide potential range for learning rates for the youngest technologies. A deeper analysis is required to understand why this discrepancy exists. For example, NEMS uses a beginning learning rate of 10% for PV, adding in the reduction from Technologic Optimism, the effective rate starts at 12.5% and by 2007 the learning rate reaches 5%. However, Grumbler et al., Mackay & Probert, and Neij all identify 20% as historical learning rates for PV. This significance of this and other discrepancies should be examined further.

3. NEMS is updated annually, so the data in this paper should be updated every few years. Technological Learning for wind plants, for example, is treated differently in AEO 2003 than it was in previous versions of AEO.

10. Appendix – Learning Algorithm

This appendix illustrates NEMS's learning factor algorithm and follows the logic used in the *ucape* source code. The first page shows a schematic representation of the algorithm. The ten steps are briefly explained on second page. The third page defines the notations or abbreviations used. The last page shows Step 6 of the algorithm, which is complicated enough to warrant it own schematic.

Figure A-1 NEMS's Learning Factor Algorithm



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Notes regarding for Learning Factor Algorithm

Step 1. Identifies the Baseline Capacity, which is needed to calculate parameter 'a' and Breakpoint Capacity.

Step 2. Identifies the vintage, which determines the value for parameter 'b' and helps determine the Breakpoint Capacity. Breakpoint Capacity is the actual capacity at which a plant's vintage changes. Only four plants in AEO 2003 surpass their Breakpoint Capacities and change vintage; Fuel cells, Photovoltaic, and Biomass plants change from Revolutionary to Evolutionary vintage, while the Advanced Combustion Turbine plants change from Evolutionary to Conventional vintage.

Steps 3 & 4. Calculates parameters "a" and "b" which help calculate the Learning Factor in Step 7.

Step 5. Identifies installed capacity for a given year, C_{year}.

Step 6. Is the calculation of the Learning Capacity, shown in Figure A-2. Learning Capacity is calculated from the actual capacity, the previous year's capacity, previous year's Learning Capacity, and the typical unit size. This step applies rules about the minimum value for Learning Capacity and the maximum year-to-year Learning Capacity increase. There are five possible ways to calculate Learning Capacity depending on the situation.

Step 7. Calculate Learning Factor the first way, from Learning Capacity.

Step 8. Calculate Learning Factor the second way, from the minimum annual learning.

Step 9. Choose actual Learning Factor, the lesser of Step 7 and Step 8.

Step 10. Next year starts and the algorithm repeats itself starting at Step 5, unless the plant type has surpassed the Breakpoint Capacity. If so, the vintage is redefined and the current year begins at Step 3.

Diamonds are decision boxes.
Ovals are variable definition steps.

Variables – known

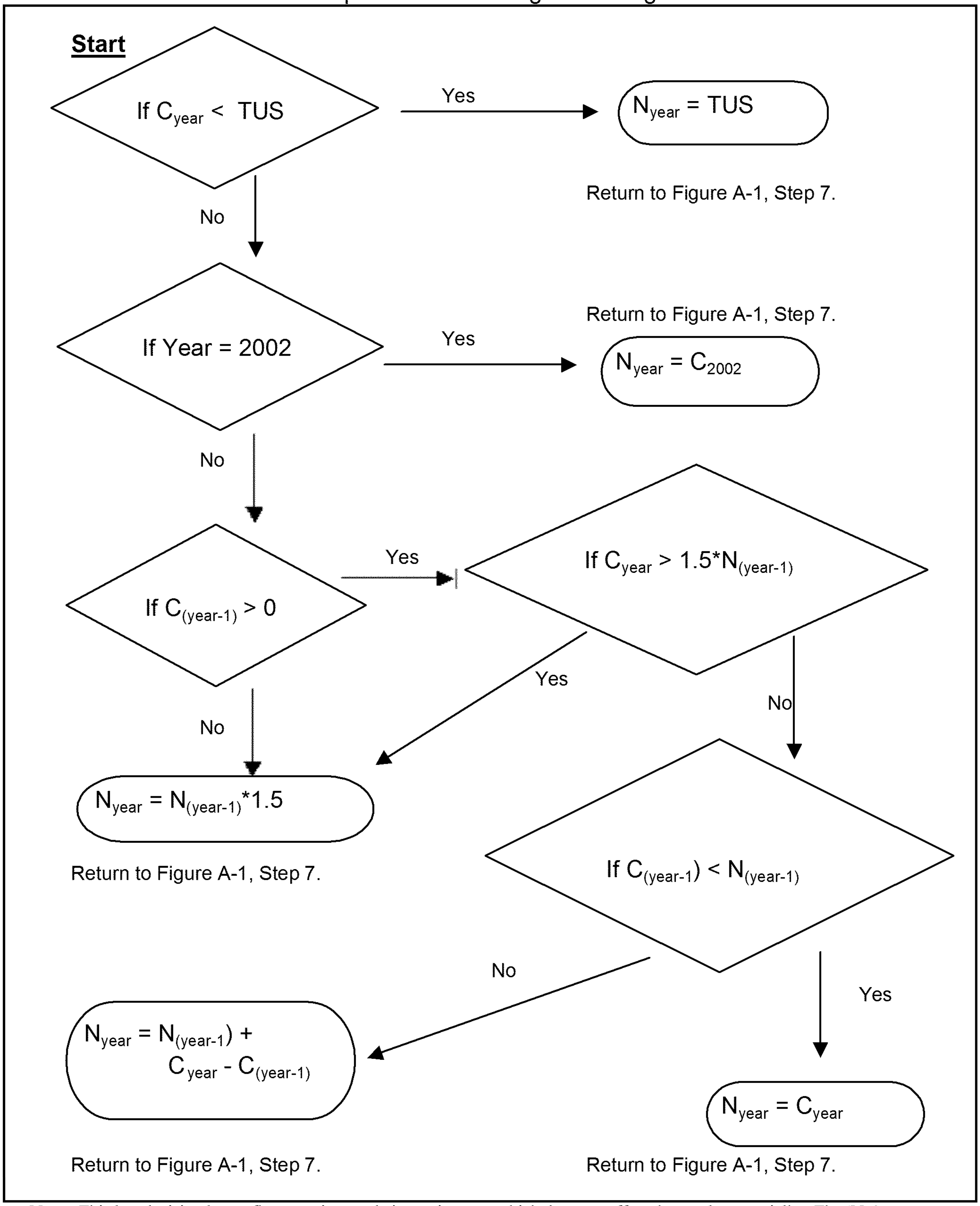
C_{2001}	2001 Capacity
C_{2002}	2002 Capacity
C_{year}	Capacity for "year"
MAL	Minimum Annual Learning
TUS	Typical Unit Size

Variables – calculated

N_{year}	Learning Capacity for "year"
LF_1	Learning Factor calculated from Learning Capacity
LF_2	Learning Factor calculated from the MAL
LF_{year}	Learning Factor for "year", the lower of LF_1 and LF_2
BC	Breakpoint Capacity is the capacity which defines when a Revolutionary or Evolutionary plants' vintage is reclassified.
'a'	parameter in Learning Function
'b'	parameter in Learning Function
X	Baseline Capacity used to calculate vintage, Breakpoint Capacity and 'a'.

The only time values for vintage, BC, 'b', and 'a' are redefined is when an Evolutionary or Revolutionary plants' vintage is reclassified.

Figure A-2 Flowchart to Calculate Learning Capacity.
Step 6 of the Learning Factor Algorithm



Note: This last decision box reflects a minor code inconsistency, which does not affect the results materially. The 'No' and 'Yes' should be switched in the source code. Fuel Cells and Pumped Storage are most affected by this inconsistency. If corrected, the net affect would be an approximately 0.5% reduction in overnight costs.

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ATTACHMENT 13

DEPARTMENT OF ENERGY

THE RECOVERY ACT:

TRANSFORMING AMERICA'S TRANSPORTATION SECTOR

BATTERIES AND ELECTRIC VEHICLES

WEDNESDAY, JULY 14, 2010

Embargoed until 8:00 PM EDT

The Recovery Act:
Transforming America's Transportation Sector

Batteries and Electric Vehicles

The Obama Administration is investing in a broad portfolio of advanced vehicle technologies. These investments—investments in American ingenuity, innovation, and manufacturing—are driving down the costs associated with electric vehicles and expanding the domestic market. Investments in batteries alone, for example, should help **lower the cost of some electric car batteries by nearly 70 percent before the end of 2015.** What's more, thanks in part to these investments, **U.S. factories will be able to produce batteries and components to support up to 500,000 electric-drive vehicles annually by 2015**. Overall, **these investments will create tens of thousands of American jobs.**

As part of the Department of Energy's $12 billion investment in advanced vehicle technologies, the Department is investing more than $5 billion to electrify America's transportation sector. These investments under the American Recovery and Reinvestment Act and DOE's Advanced Technology Vehicle Manufacturing (ATVM) Loan Program are supporting the development, manufacturing, and deployment of the batteries, components, vehicles, and chargers necessary to put millions of electric vehicles on America's roads.

The Recovery Act included $2.4 billion to establish 30 electric vehicle battery and component manufacturing plants and support some of the world's first electric vehicle demonstration projects. For every dollar of the $2.4 billion, the companies have matched it at minimum dollar for dollar. Additionally, DOE's Advanced Research Projects Agency-Energy (ARPA-E) is providing over $80 million for more than 20 transformative research and development projects with the potential to take batteries and electric drive components beyond today's best technologies, and the Advanced Energy Manufacturing Tax Credit program is helping expand U.S.-based manufacturing operations for advanced vehicle technologies.

The Obama Administration has also provided nearly $2.6 billion in ATVM loans to Nissan, Tesla and Fisker to establish electric vehicle manufacturing facilities in Tennessee, California and Delaware, respectively.

Projects have now begun constructing new manufacturing plants, adding new manufacturing lines, building electric vehicles, and installing electric vehicle charging stations, creating thousands of new jobs across the country. These combined investments are helping the economy grow now, while positioning the U.S. for global leadership in the electric vehicle industry for years to come.

Recovery Act Investments in Electric Vehicles

Through the Recovery Act, the country is making comprehensive investments in each part of the electric vehicle ecosystem. In sum, the Act included approximately $4 billion to support domestic manufacturing and deployment for advanced vehicle and clean fuel technologies. To date, there have been over 70 awards, worth more than $2.5 billion, to promote electric vehicle technologies. This includes cost-shared projects at each level along the innovation chain – from battery and component manufacturing to commercial deployment of vehicles and charging stations to advanced research and development that will help identify the next generation of electric vehicle technologies.

- **Manufacturing** – 26 of 30 battery and component manufacturing plants have started construction, which includes breaking ground on new factories or installing new equipment in existing facilities.

  - 9 battery manufacturing projects, including a $249 million project by A123 to support the construction of 3 Michigan facilities to produce advanced batteries for vehicles, grid storage, and other applications. They have already started construction of a low-volume manufacturing facility in Livonia, which they expect to begin operations in September, and have begun planning for larger-volume facilities in Romulus and Brownstown, Michigan. Nine of the nine new battery plants opening as a result of Recovery Act investments will have started construction by tomorrow – and four of those will be operational by the end of the year.

  - 11 battery component manufacturing facilities, including Celgard LLC in North Carolina, who won a $49.2 million grant to expand its production capacity for separators, a key component in the lithium-ion batteries needed for the growing electric drive vehicle market. When Celgard completes expanding its facility in Charlotte, North Carolina, the company will be able to produce an additional 80 million square meters of separator per year—enough to support up to a million electric-drive batteries per year. Celgard is also building a new manufacturing facility in Concord, North Carolina to support additional increased demand for electric vehicle batteries.

  - 10 electric drive component manufacturing projects, including Delphi Automotive Systems, the largest North American supplier of power electronic components for electric vehicles. The company received $89.3 million in Recovery Act support to build a power electronics manufacturing facility in Kokomo, Indiana. The plant will have the production capacity to support at least 200,000 electric drive vehicles by the end of 2012.

- **Deployment** – 8 innovative demonstration projects, representing the world's largest electric vehicle demonstration to date. In total, these projects will lead to an additional 13,000 grid-connected vehicles and 20,000 charging stations in residential, commercial and public locations nationwide by December 2013**.**

    - Coulomb Technologies received a $15 million Recovery Act grant to support the ChargePoint America program, which will deploy 5,000 residential and commercial charging stations and 2,600 electric drive vehicles in nine major metropolitan areas around the country.

- **Advanced Research and Development -** More than 20 breakthrough research projects to support potential game-changing technologies like semi-solid flow batteries, ultracapacitors and "all-electron" batteries that could go well beyond today's best lithium-ion chemistries are being funded. **If successful, these breakthroughs could cut battery costs by as much as 90 percent and expand vehicle range three to six-fold.** In turn, this would decrease the upfront cost of electric cars to roughly that of gas-powered cars and give them a longer range, likely further increasing demand for the vehicles in the long-term.

    - Fluidic Energy won $5 million to pursue "metal air" batteries that could have 10 times the energy density of today's lithium-ion technologies, at a third of the cost. The Scottsdale, Arizona company is working with Arizona State University to develop ultra stable new materials, or "wonder fluids" that could allow metal-air batteries to be successfully developed and deployed for the first time, enabling widespread deployment of low cost, very long range electric vehicles.

Taken together, the impact of these investments is greater than the sum of their parts. The investments interact to stimulate both supply and demand for electric vehicles. The investments are lowering barriers to ownership: driving down the cost of batteries while improving their functionality and building a network of charging stations. Meanwhile, they are actively putting more electric cars on the road and supporting the long-term domestic production of low-cost, clean energy vehicles.

Federal investments in electric vehicles are being matched by private sector funding, helping to move private capital off of the sidelines. This combination of private and public investments in advanced vehicles is stimulating economic growth, creating jobs in both the short- and long-term, and increasing the country's global competitiveness.

These jobs represent a shift—the shift of important industries moving jobs back to American shores and the growth of a domestic battery industry. The Recovery Act is laying the groundwork for long-term, sustainable recovery by ensuring that the industries of the future are American industries. In 2009, the United States had only two factories manufacturing advanced vehicle batteries and produced less than two percent of the world's advanced vehicle batteries. By 2012, thanks in part to the Recovery Act, 30 factories will be online and the **U.S. will have the capacity to produce 20 percent of the world's advanced vehicle batteries. By 2015, this share will be 40 percent.**

This shift has additional benefits, too. Today, oil provides 95% of the power to move America's cars, trucks, ships, rail, and planes, and over half of America's oil is imported. Electric vehicles and other advanced vehicle technologies can reduce this dependence and help the country control its energy future.

Electric Vehicle Supply Chains and Networks

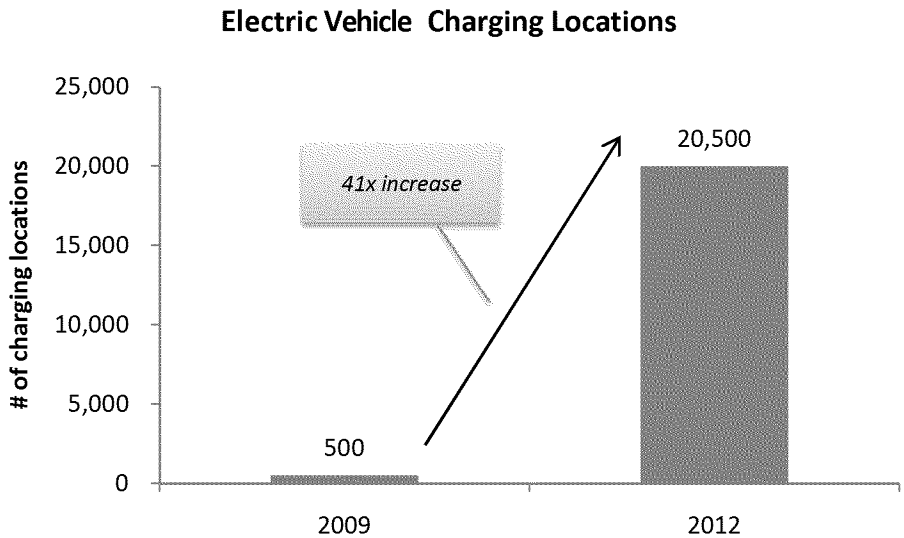
Through the Recovery Act and the ATVM program, DOE is invigorating a nationwide advanced vehicle supply chain centered in the Midwest. Michigan is an example of how clusters can multiply the impact of Recovery Act funds and create synergies within and across corporate walls. A concentration of Michigan's engineers, workers, and managers are innovating more quickly because they are near one another – and drawing in more and more advanced vehicle expertise each day.

The Recovery Act is supporting 14 vehicle awards in Michigan. This includes several large battery factories (e.g. A123, GM, Johnson-Controls, Dow-Kokam, and LG Chem), electric drive component factories (e.g. GM, Ford, Magna), and three workforce training programs (University of Michigan, Michigan Technological University, and Wayne State). Under the Department's loan program, DOE is supporting multiple Michigan-based factories that will hire the workers trained in these universities to assemble the batteries and components into some of the world's most advanced vehicles.

For example, a $105 million grant to GM is expanding a facility to package batteries for the Chevy Volt – the grant is creating hundreds of jobs at the Brownstown facility and invigorating a chain of local factories. GM will deliver batteries from Brownstown to a plant in Detroit. Here, hundreds of workers will assemble components made in Warren, Grand Blanc, and three factories in Flint. This network of Volt-related investments is attracting other companies to Michigan. To supply battery cells to the Brownstown facility, Compact Power, Inc. is building its first American factory in Holland, Michigan. The $151 million grant is helping Compact hire workers in Holland and purchase battery components and supplies from U.S. factories. Compact will purchase its separator material from Celgard, and is evaluating other Midwestern suppliers for its other components like cathodes, electrolytes, additives, and binders.

Meanwhile, under the Recovery Act's Transportation Electrification program, grantees will deploy 20,000 additional electric charging locations, up from 500 locations today. These 8 demonstration projects are also putting 13,000 electric vehicles on the road, including more than

4,700 Chevy Volts, across more than a dozen cities to show how electric cars perform under real driving, traffic and weather conditions.



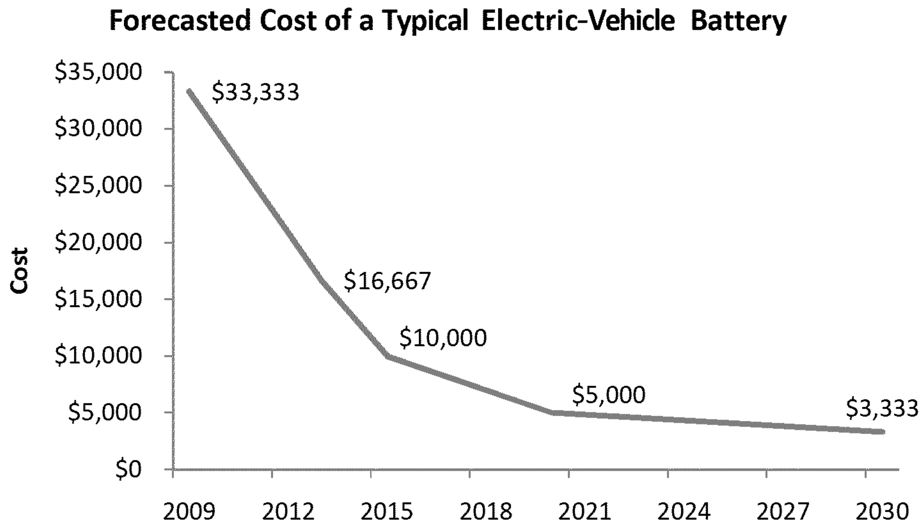
Innovation in Batteries

The Obama Administration's investments in advanced vehicles are creating a sustainable future for American industry and American workers. But investments in batteries demand special attention. The lack of affordable, highly-functional batteries has been a particularly high barrier to the widespread adoption of electric vehicles. When the Recovery Act passed, batteries were too costly, too heavy, too bulky and would wear out too quickly. Recovery Act investments are literally reshaping electric batteries and reshaping the economics of battery production and distribution.

More Affordable

Before the Recovery Act, the only highway-enabled electric vehicle on the road cost more than $100,000. This high cost resulted in large part from the high cost of batteries—a car with a 100 mile range required a battery that cost more than $33,000.

Between 2009 and 2013, the Department of Energy expects battery costs to drop by half as 20 Recovery Act-funded factories begin to achieve economies of scale. By the end of 2013, a comparable 100 mile range battery is expected to cost only $16,000. By the end of 2015, Recovery Act investments should help lower the cost of some electric car batteries by nearly 70 percent to $10,000. The same cost improvement applies to plug-in hybrids – cars that can travel roughly 40 miles on electricity before their gasoline engine kicks in. The cost of a 40-mile range battery is falling from more than $13,000 in 2009, to roughly $6,700 in 2013, to $4,000 in 2015.



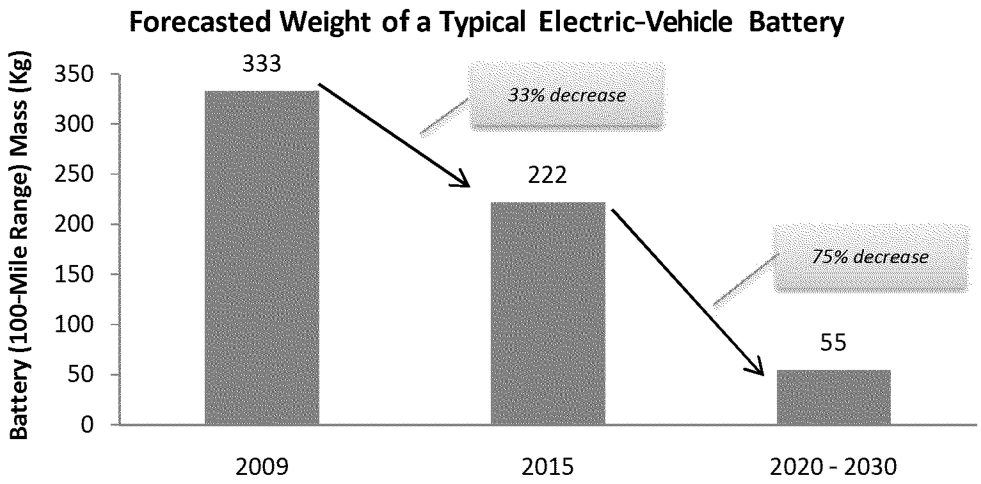
Note: Assumes 3 miles per kilowatt hour and 100-mile range. Source: U.S. DOE Vehicle Technologies Program.

This dramatic drop in cost should result in more affordable, mainstream electric cars. Fisker, GM, Nissan, Tesla, and other automakers are introducing more affordable electric vehicles. At the end of this year, consumers will be able to purchase electric vehicles that cost between $25,000 and $35,000, after tax credits. In addition, drivers will save money over a car's lifetime. Using electricity to power a car is only about 30 percent of the cost of using three-dollar-a-gallon gasoline.

Lighter Weight

Low energy density, i.e. heavier batteries, significantly limits vehicle range and acceleration. Under the Recovery Act, DOE is supporting innovations to reduce battery weight and increase the energy density, which allows batteries to store more energy in a smaller, lighter package. These smaller, lighter batteries will pack **more power, performance, and range.**

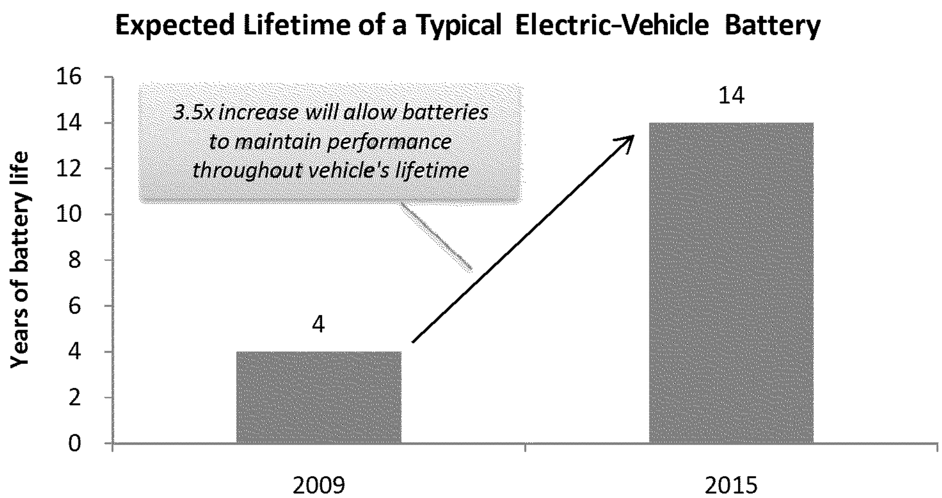
Between 2009 and 2015, increases in energy density will reduce the typical weight of an electric vehicle battery by 33 percent. Meanwhile, ARPA-E projects are pursuing innovations that have the potential to improve battery density up to six times its current level.



Note: Assumes 3 miles per kilowatt hour and 100-mile range. Source: U.S. DOE Vehicle Technologies Program.

Longer Lasting

Batteries are also getting more durable. In the next few years, domestic manufacturers should be able to produce batteries that last up to 14 years. This should give consumers confidence that electric vehicle batteries will last the full life of the vehicle. In addition, longer lasting batteries reduce the potential for used batteries to become waste material.[1]



Note: Assumes drivers will charge their vehicles 1.5 times per week. Source: U.S. DOE Vehicle Technologies Program.

[1] Calendar life is assumed for advanced electric vehicle battery technologies. Current batteries for PHEV vehicles are designed to achieve significantly higher calendar life, but trade-off performance and cost to achieve that life.

ATTACHMENT 14

SANDIA REPORT
SAND2011-2419
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Printed April 2011

Power Tower Technology Roadmap and Cost Reduction Plan

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Prepared by
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Power Tower Technology Roadmap and Cost Reduction Plan

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Abstract

Concentrating solar power (CSP) technologies continue to mature and are being deployed worldwide. Power towers will likely play an essential role in the future development of CSP due to their potential to provide dispatchable solar electricity at a low cost. This Power Tower Technology Roadmap has been developed by the U.S. Department of Energy (DOE) to describe the current technology, the improvement opportunities that exist for the technology, and the specific activities needed to reach the DOE programmatic target of providing competitively-priced electricity in the intermediate and baseload power markets by 2020. As a first step in developing this roadmap, a Power Tower Roadmap Workshop that included the tower industry, national laboratories, and DOE was held in March 2010. A number of technology improvement opportunities (TIOs) were identified at this workshop and separated into four categories associated with power tower subsystems: solar collector field, solar receiver, thermal energy storage, and power block / balance of plant.

In this roadmap, the TIOs associated with power tower technologies are identified along with their respective impacts on the cost of delivered electricity. In addition, development timelines and estimated budgets to achieve cost reduction goals are presented. The roadmap does not present a single path for achieving these goals, but rather provides a process for evaluating a set of options from which DOE and industry can select to accelerate power tower R&D, cost reductions, and commercial deployment.

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1. Introduction

In recent years there has been a resurgent interest in concentrating solar power (CSP) power tower technologies, with at least five companies currently pursuing the development of commercial power tower projects: Abengoa Solar, BrightSource Energy, eSolar, SolarReserve, and SENER. One of the reasons for the renewed interest in power tower technology is that power towers offer high efficiencies and, therefore, the opportunity for low-cost electricity. In addition, power towers can readily integrate thermal energy storage into their operation to achieve high capacity factors, which can provide for cost-effective, dispatchable electricity to serve the needs of the intermediate and baseload power markets.

In March 2010, the U.S. Department of Energy (DOE) and Sandia National Laboratories hosted a Power Tower Roadmap Workshop that included participation of the power tower industry, the national laboratories, and DOE. At the workshop, areas of discussion included the current status of power tower technology, a number of Technology Improvement Opportunities (TIOs), and cost-reduction goals for power tower systems and subsystems. After the workshop, further evaluation of the TIOs was performed, resulting in a levelized cost of energy (LCOE) analysis that identified the potential for a 40% reduction in power tower LCOE by the end of the decade. If this LCOE reduction can be achieved, power towers will likely become competitive with newly constructed conventional fossil-fired power plants in both the intermediate and baseload power markets.

Commercial power tower plants with power ratings greater than 100 MW_e or more are now being pursued and constructed in the USA. These tower projects are more than ten times larger than the 10 MW_e Solar One and Solar Two power tower demonstrations sponsored by DOE in the 1980s and 1990s. The success of these first projects should lead to investment in future power tower projects. For commercial power tower projects to be successful, close cooperation will be required among all stakeholders, including the power tower industry, DOE, national laboratories, international partners, utilities, and the financial community.

1.1. Power Tower Background

The Solar One project — a joint undertaking of the U.S. DOE, Southern California Edison Company (SCE), Los Angeles Department of Water and Power, and the California Energy Commission — was a 10 MW_e water-steam solar power tower facility built in Barstow, CA. Solar One was instrumental in helping to prove that central receiver technology is effective, reliable, and practical for utility-scale power generation. It operated from 1982 to 1988 and ultimately achieved 96% availability during hours of sunshine [1].

A few years later, the Solar One steam-receiver plant was redesigned into a power tower plant named Solar Two, which employed a molten-salt receiver and thermal energy storage system. The change from steam to a molten-salt working fluid was made primarily because of the ease of integrating a highly efficient (~99%) and low-cost energy storage system into a molten-salt plant design. The project was developed by the U.S. DOE along with a consortium of utilities led by SCE. Solar Two operated from 1996 to 1999 and helped validate nitrate salt technology, reduce the technical and economic risks of power towers, and stimulate the commercialization of CSP power tower technology. The baseline power tower used in this roadmap utilizes the data generated by the Solar Two project.

Due to budget constraints, DOE removed most power tower activities from the CSP Program portfolio after the decommissioning of Solar Two. As a result, virtually no work was performed on power towers in the U.S. for nearly a decade. Recent increases in budgets and a renewed interest in power towers have led the DOE CSP Program to reintroduce power towers into its portfolio. As mentioned above, the primary reasons for this reintroduction are the broad interest among industry to develop power towers, the potential for high-temperature operation, and the ability to effectively integrate thermal energy storage, thereby producing dispatchable electricity.

Experimental power tower test facilities are currently located at Sandia's National Solar Thermal Test Facility (NSTTF) in Albuquerque, New Mexico, USA; the Plataforma Solar de Almeria in Spain; the Julich Solar Tower in Germany; the Weizmann Institute of Science in Israel; the CSIRO National Solar Energy Centre in Australia; and the Odeillo and THEMIS Solar Power Towers in France. In addition, private industry has built small-scale tower demonstration facilities in the USA, Spain, and Israel.

Commercial electricity-generating power tower plants in operation today include Abengoa's PS10 (11 MW_e) and PS20 (20 MW_e) steam towers in Spain and eSolar's Sierra SunTower (5 MW_e) steam towers in California. Commercial electricity-generating power tower plants under construction include BrightSource Energy's Ivanpah (392 MW_e) steam towers in California and Torresol Energy's (SENER and Masdar) Gemasolar (17 MW_e) molten-salt tower in Spain. SolarReserve has also announced their intention to construct utility-scale, molten-salt power towers near Tonopah, Nevada, and Palm Springs, California.

1.2. Roadmap Approach

As outlined in the DOE Solar Energy Technologies Program (SETP) Multi-Year Program Plan 2007-2011, the development of a technology roadmap consists of four steps:

1. Determine baseline and goals for component costs and performance;
2. Identify technology improvement opportunities (TIOs);
3. Assess and prioritize TIOs; and
4. Develop a multi-year task portfolio.

The first three steps of this process were initiated at a Power Tower Roadmap Workshop held at Sandia's NSTTF in Albuquerque, NM on March 24-25, 2010. Participants were asked to discuss costs, performance, and research needs for the following subsystems:

1. Solar Collector Field (Heliostats);
2. Solar Receiver;
3. Thermal Energy Storage; and
4. Power Block / Balance of Plant.

During the workshop, facilitators led group discussions in each of these four areas. Current and future costs were collectively discussed, and R&D needs associated with component performance and cost reductions were identified. At the end of the two-day workshop, participants prioritized the topics they thought were most important for cost reduction and could be supported by DOE, and the results were then tabulated. After the workshop, Sandia conducted a more detailed assessment of the potential impact of the identified TIOs on LCOE.

1.3. Purpose and Objectives

One of the goals of the DOE CSP Program is to achieve large-scale deployment of CSP technologies, including power tower systems, so that they become major contributors to domestic energy supply. Of course, deployment will be encouraged by lower power tower system costs, higher costs of the competition (e.g. carbon pricing), or a combination of the two. However, large-scale deployment will also require that utilities and investors observe the successful operation of power tower plants and recognize the value of energy storage and dispatchability of electricity. There are currently Power Purchase Agreements (PPAs) for approximately 8,200 MW of new CSP plants in the U.S. and, of these, approximately 3,100 MW involve power towers [2]. For even a fraction of these plants to be financed and built, it is critically important that the first round of new plants be successful. DOE and the national laboratories can provide support for these first commercial power tower projects, including component testing, systems analysis, process optimization, and rapid feedback to industry.

DOE has developed this Power Tower Technology Roadmap to describe the current technology, the improvement opportunities that exist for the technology, and the specific activities needed to reach the DOE programmatic target of providing competitively-priced electricity in the intermediate and baseload power markets by 2020. The roadmap will be used to evaluate the current DOE CSP Program portfolio and guide future funding areas and budget allocations. Furthermore, it will be a source of input for the next Solar Energy Technologies Program (SETP) Multi-Year Plan.

The remainder of this roadmap is broken into the following three main sections:

- Power Tower Cost and Performance Goals: describes the baseline system, current costs, and cost goals for power tower systems;
- Technology Improvement Opportunities: identifies and discusses specific TIOs that will lead to the required cost reductions; and
- Recommended Activities and Spend Plan: provides a 10-year schedule of potential programmatic activities, costs, and their impact on LCOE.

2. Power Tower Cost and Performance Goals

In 2009, the DOE CSP Program set a goal to reduce the LCOE of CSP technology of a hypothetical 100 MW plant from today's costs of approximately 15¢/kWh to a value in 2020 of 9¢/kWh or less.[1] In other words, the goal was to cut the cost by 40% over ten years. Although a 30% investment tax credit (ITC) is in effect until 2016, this analysis uses a 10% ITC for both present and future costs to reveal the actual improvement that is necessary.

Table 1 summarizes the baseline costs and future cost goals for power tower subsystems.

[1] In 2011, this goal was updated to a value of 6¢/kWh or less with no subsidies by the end of the decade as part of the DOE SunShot Initiative. For more information, see Section 5.

Table 1. Baseline costs and Roadmap Workshop cost goals for commercial power towers

	Solar Field	Solar Receiver	Thermal Storage	Power Block	Steam Generation	O&M
Today's Baseline	$\$200/m^2$	$\$200/kW_t$	$\$30/kWh_t$	$\$1000/kW_e$	$\$350/kW_e$	\$65/kW-yr
Workshop Goal	$\$120/m^2$	$\$170/kW_t$	$\$20/kWh_t$	$\$800/kW_e$	$\$250/kW_e$	\$50/kW-yr

The baseline costs identified above are based on information from four sources:

- responses to a confidential questionnaire that was distributed by Sandia to power tower developers;
- escalation to 2010 dollars of power tower subsystem costs reported in the 1988 U.S. Utility Study [3];
- a recent study by Abengoa Solar that included molten-salt power towers [4]; and
- a 2007 study of heliostat costs by Sandia National Laboratories [5].

The baseline power tower used in this roadmap is a 100 MW_e plant assumed to have a solar multiple of 2.1, a heliostat field size slightly larger than 1,000,000 m^2, a 540 MW_t surround receiver, and 9 hours of thermal storage. The receiver and field size represent a direct scale-up of the technology demonstrated at DOE's Solar Two project. Furthermore, this baseline is only 15% larger than the plant that was chosen for the U.S. Utility Study, allowing for a more direct use of the cost data that was developed in that study. Given a power tower plant with a 540 MW_t receiver and a 100 MW_e turbine, the System Advisor Model (SAM) predicts the lowest LCOE to result with 9 hours (i.e. 2340 MWh_t) of 2-tank, sensible heat, molten-salt thermal storage. It should be noted that the majority of U.S. utilities do not presently value storage beyond a few hours; however, the focus of this analysis is reaching the lowest possible LCOE[2]. Using the baseline subsystem costs shown in Table 1, SAM models were run to predict the performance of a baseline plant with a direct capital cost of \$552M and an indirect cost of \$192M, yielding a total installed cost of \$744M, or \$7400/kW. The annual capacity factor of the baseline plant is 48%. As shown in Figure 1, the LCOE for this plant with a 10% ITC is 15.0¢/kWh. Figure 1 also includes the LCOE impact of realizing the cost goals displayed in Table 1. If these targets are reached, power tower systems can achieve a real LCOE of less than 8¢/kWh.

[2] If the same 540 MW_t receiver is coupled with a 200 MW_e turbine, the optimum amount of storage is only a few hours.

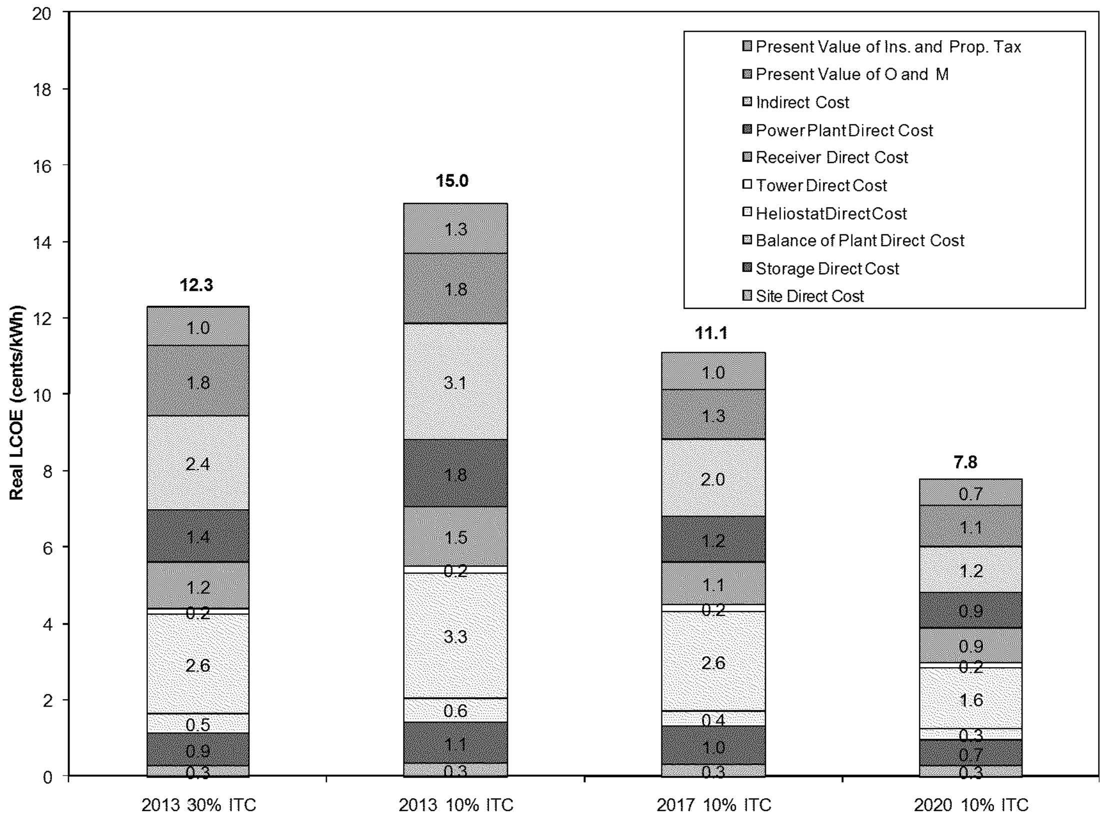

Figure 1. Projected LCOE (real 2010 dollars) and associated costs of individual components (The 2013 case is shown with both a 30% and 10% ITC)

The total installed cost is the sum of direct and indirect costs; direct costs are essentially the capital costs of the plant, and indirect costs are obtained by multiplying direct costs by a given percentage. For the 2013 10% ITC case in Figure 1, direct costs alone account for 8.8¢/kWh of the 15.0¢/kWh total. Of this 8.8¢/kWh, direct costs break out into 3.3¢/kWh (38%) for heliostats, 1.8¢/kWh (20%) for power plant, 1.7¢/kWh (19%) for receiver/tower, 1.1¢/kWh (13%) for storage, 0.6¢/kWh (7%) for balance of plant, and 0.3¢/kWh (3%) for site preparation. The cost breakdowns for the four main subsystems—solar collector field, solar receiver, thermal energy storage, and power block / balance of plant—are detailed in the following sections of this roadmap.

It is important to note that the predicted baseline LCOEs for steam and molten-salt power tower technologies are nearly identical. Although the analysis presented in Figure 1 is based on a molten-salt power tower with several hours of energy storage, modeling a steam tower system with little to no storage results in an LCOE prediction within 1¢/kWh of the 2013 values shown in Figure 1. In addition, much of the cost reduction potential identified for molten-salt power towers also applies to steam receiver towers.

3. Technology Improvement Opportunities (TIOs)

From a technical standpoint, the LCOE of a power tower can be reduced in two ways: 1) by increasing annual performance of the plant (both initial and long-term) and 2) by lowering costs of the plant (both capital and O&M). This roadmap addresses both avenues to power tower plant cost reduction.

Power tower performance can be increased by:

- improving plant availability;
- improving the optical efficiency (including tracking accuracy) of the heliostat field;
- reducing the thermal losses of the receiver;
- increasing receiver operating temperature to power higher-efficiency power cycles;
- increasing thermal storage efficiency; and/or
- reducing parasitic losses and improving operational efficiency.

One way to characterize the annual performance of a power tower plant is through annual solar-to-electric conversion efficiency. This metric includes all of the energy losses that affect the annual electricity produced by the plant, including optical, thermal, electrical parasitics, and equipment unavailability losses.

During Solar One's final year of operation (1988), the annual efficiency was 10.7% gross and 7.7% net (including parasitics) given the achieved plant availability of 96% [1]. Solar Two did not operate long enough to achieve a reliable daily operation; while Solar One operated for 10,000 hours, Solar Two operated for less than 2,000 hours. Thus, it is difficult to estimate an annual efficiency for Solar Two. During PS10's second year of operation (2008), the annual efficiency was 11.5% gross.[3] Since parasitics were not reported, a net annual efficiency could not be estimated.

Due to their small size, the power blocks for Solar One and PS10 did not incorporate a reheat loop, which resulted in a relatively low thermal-to-electric conversion efficiency of approximately 31%. However, reheat will be incorporated into each of the three steam power towers at Ivanpah, which will raise turbine thermal-to-electric conversion efficiency to approximately 42%. If Solar One or PS10 had used reheat, the gross annual efficiencies would have been approximately 15%, which may represent a good target for future water-steam power towers.[4]

The annual efficiency predicted using SAM (Beta version) for the baseline 100 MW_e molten-salt power tower plant operating in Barstow, California is 16.0% gross and 14.8% net assuming a plant availability of 90%. These values are nearly identical to the efficiency values (16.3% gross and 14.6% net) predicted using the SOLERGY code in 1999 for a commercial molten-salt power tower based on lessons learned from Solar Two [1]. Thus, these values are used as the annual efficiencies for the baseline molten-salt power tower.

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[3] PS10 produced 21,400 MWh (gross) in 2008 [6]. The plant is allowed to burn 15% natural gas. Annual DNI in Sevilla near the plant was approximately 2.1 MWh/m^2 in 2008 [7]. Heliostat field area is 74,880 m^2. Thus, 21400*0.85/(74880*2.1) = 11.5%.

[4] Peak efficiencies (i.e. design point) for power towers typically exceed 22%. However, annual efficiency is used here rather than peak efficiency because annual efficiency is more relevant for LCOE calculations. Some power tower developers predict annual efficiencies of 18% or higher; however, such analyses usually assume 100% equipment availability and/or perfectly clean mirrors. The values contained in this roadmap assume outages and other real-world effects.

Power tower cost can be reduced by:

- reducing equipment capital cost via reduced material content, lower-cost materials, more efficient design, or less expensive manufacturing and shipping costs;
- reducing field assembly and installation costs via simpler designs and minimization and/or ease of field assembly;
- lowering operation and maintenance costs through improved automation, reducing need (as with more reliable components), and better O&M techniques;
- building larger systems that provide economies of scale; and/or
- deploying more systems to benefit from learning-curve effects.

The cost of electricity generated by a solar power tower system is dependent on the capital cost, the annual performance, and the annual operations and maintenance cost.[5] The capital equipment for a power tower plant consists of solar components (heliostats, solar receivers, steam generators, and storage) and the use of more-or-less conventional Rankine-steam-cycle components. While current tower projects utilize subcritical Rankine steam cycles, it is feasible for power towers to transition to supercritical Rankine steam cycles that operate at higher temperatures and convert solar heat at a much higher efficiency (50% thermal-to-electric efficiency for supercritical versus 42% for subcritical). This roadmap focuses on improvements to the solar-specific components; however, the need to adapt existing supercritical Rankine plant equipment for power tower applications is also addressed.

In the following sections, potential opportunities for performance improvement and cost reduction in the four subsystem areas, as well as O&M, are described.

3.1. Solar Collector Field

3.1.1 Current Status

There is no consensus among power tower developers regarding the optimum size of a heliostat, and heliostats ranging between 1 m^2 and 130 m^2 are being developed. Simplified heliostat-scaling theory, described in Sandia's Heliostat Cost Reduction Study [5], indicates that capital costs can be proportional to $Area^{1.5}$, which would favor smaller heliostats. However, the more detailed investigation described in the same study (including O&M, field wiring, and some manufacturing quotes on heliostat subcomponents) show that lowest life-cycle cost may ultimately be achieved with heliostats larger than 50 m^2. The optimum heliostat size — if in fact one exists — will be better understood as the power tower industry continues to deploy and operate more systems.

As shown in Table 2, the current cost of the solar field is dominated by four components for both large and small heliostats. For large heliostats, the major cost drivers are drives (27%); manufacturing facilities / profit (23%); mirror modules (22%); and pedestal / mirror support structure / foundation (19%). For small heliostats, the major cost drivers are drives (30%); manufacturing facilities / profit (23%); field wiring and controls (19%); and mirror modules (16%). It is interesting to note that "pedestal / mirror support structure / foundation" costs

[5] Electricity cost is also dependent on financial assumptions. The financial assumptions used in this analysis are the SAM default values assuming plant ownership by an independent power producer.

impact large heliostats more than small heliostats, as large heliostats experience higher wind loads and require more structural steel (per m^2 of surface area) to maintain a rigid structure and survive worst-case wind storms. It is also interesting to note that "field wiring and controls" costs impact small heliostats more than large heliostats, as small heliostats require more complex field wiring and controls due to the increased number of heliostats in the field.

Table 2. Cost of solar collector field subsystem [\$/m^2] expressed in 2010 dollars [5]

Heliostat Component	**30 m^2 size 235,000 m^2 7800 helios one time**	**148 m^2 size 235,000 m^2 1600 helios one time**	**148 m^2 size 740,000 m^2/yr 5,000 helios/yr**	**148 m^2 size 7,400,000 m^2/yr 50,000 helios/yr**	**Roadmap Workshop Baseline**
Mirror Modules	39	43	29	25	–
Drives	71	52	52	29	–
Pedestal, Mirror Support Structure, Foundation	17	38	48	44	–
Controls and Wired Connections	27	8	5	4	–
Field Wiring	18	8	9	8	–
Manufacturing Facilities and Profit	54	45	26	20	–
Installation and Checkout	11	4	8	7	–
Total Capital Cost	**\$237/m^2**	**\$196/m^2**	**\$177/m^2**	**\$137/m^2**	**\$200/m^2**
O&M Cost (life-cycle cost)	\$16/m^2	\$7/m^2	–	–	–

As mentioned above, the Roadmap Workshop Baseline cost is a "rolled-up" value based primarily on responses obtained during the Roadmap Workshop. Columns 1 and 2 of Table 2 were estimated in year 2000, and columns 3 and 4 were estimated in year 2006. Due to minor changes in certain aspects of the cost categorization between 2000 and 2006, a normalization using the year 2000 categories was performed.[6] The values in Table 2 indicate that large heliostats may have lower capital and O&M costs when supplying heliostats for a single plant (comparing columns 1 and 2).[7] However, small heliostats display better optical performance than large heliostats and, with a performance improvement value of $10/m^2 or more, the cost differential is narrowed [5]. Table 2 also indicates that multi-plant / multi-year-production scenarios can significantly reduce the cost for a given heliostat design (comparing columns 2 and 3) and that ramping up to a highly automated production line also has a significant impact on cost reduction (comparing columns 3 and 4).

3.1.2 Future Improvement Opportunities

The solar collector field (materials plus labor) is the largest single capital investment in a power tower plant, and thus represents the greatest potential for LCOE cost reduction among capital equipment costs. Unfortunately, a comprehensive DOE R&D plan for power tower solar fields is complicated by the variations in heliostat designs among industry. As described above, each commercial power tower company is developing their own heliostat, ranging in size from 1 m^2 to 130 m^2. Thus, the solar field TIOs identified attempt to focus on common areas that would be beneficial to the industry at large. These include:

- Drives and controls: The most expensive part of the heliostat is the azimuth drive, and therefore next-generation, low-cost drives that employ less conservative or alternative designs must be developed. Control algorithms that maintain less than 1 milliradian pointing accuracy are also needed for accurate positioning of heliostats at long slant ranges (i.e. for large fields).
- Heliostat support structure: Survival wind-loads dominate heliostat design criteria, and therefore experimental validation of models is necessary to optimize future heliostat designs that are more material-efficient. The optical and structural performance of today's heliostats must be fully characterized during operating and high-wind conditions through both analytical modeling and empirical experimentation.
- Manufacturing facilities: Highly-automated facilities and equipment to support the low-cost manufacture and installation of heliostats will lead to cost reduction. Improved construction, assembly, and installation methods can reduce construction time, which in turn reduces financial risk and improves time to market.
- Reflectors, coatings, and cleaning techniques: Optical efficiency is critical to overall plant performance, and a highly reflective facet surface — in terms of both total hemispherical and specular reflectance — is the first step in minimizing optical losses. In addition, passive (e.g. anti-soiling coatings) and active (e.g. optimized low-to-no water cleaning techniques) methods of keeping the reflector surface clean play a key role in reducing the O&M of the solar field. Developing low-cost reflectors —

[6] See Appendix A of [5] to fully understand the cost categories defined in year 2000. A few relatively small inconsistencies can be seen between the year 2000 and year 2006 studies; for example, mirror support structure and installation and checkout costs increased in year 2006 even though production rates were higher in the 2006 study.
[7] Reflector area would power an early-deployment plant on the order of 30 MW$_e$.

both glass and non-glass — with increased reflectivity and durability is also imperative to reducing the cost of heliostats.

Figure 2 shows the potential impact of solar collector field cost reductions and performance improvements on LCOE. Results are based on the baseline power tower model with individual parameters varied one at a time in SAM.[8]

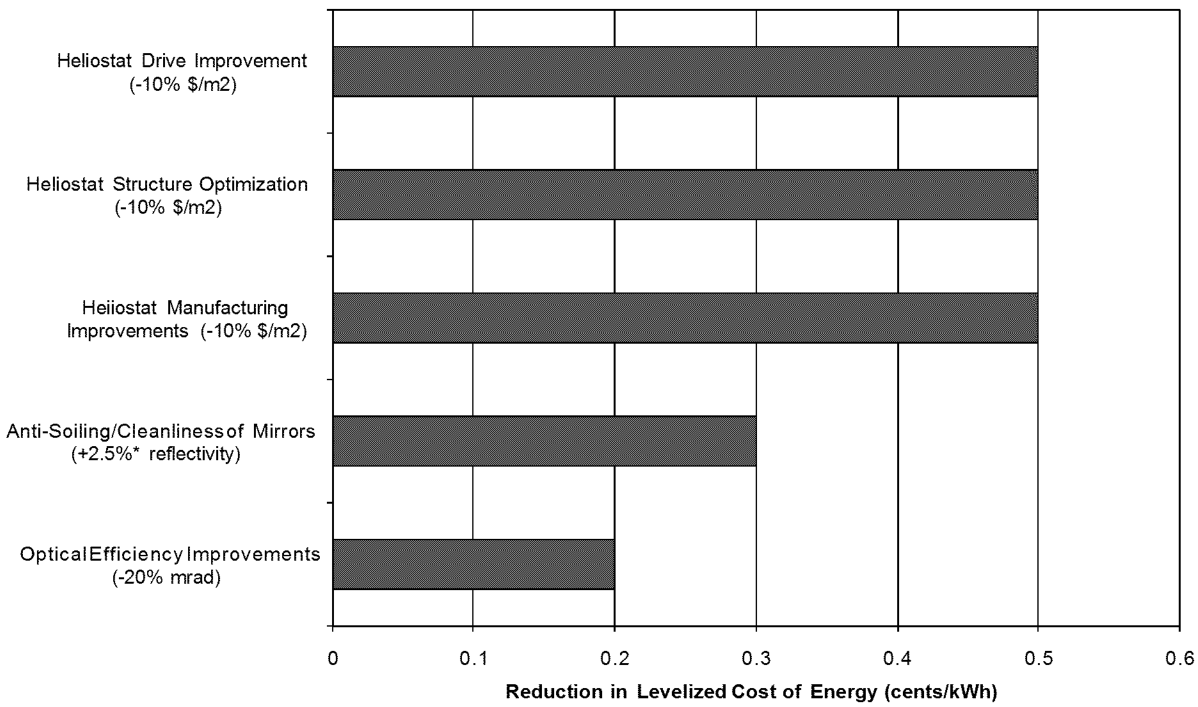

Figure 2. Potential impact of solar collector field cost reductions and performance improvements on LCOE (*absolute percentage improvement)

3.2. Solar Receiver

3.2.1 Current Status

The baseline solar receiver is a scaled-up version of the receiver used at Solar Two. The external receiver used at Solar Two consisted of 24 panels of thin-walled, metal tubes through which salt flowed in a serpentine path. The panels formed a cylindrical shell that surrounded the associated piping, structural supports, and control equipment. The external surfaces of the tubes were coated with a black Pyromark paint that provided an absorptivity of 95% and an emissivity of 88%. The receiver was designed to accept a maximum amount of solar energy in a minimum area to reduce heat losses due to convection and radiation. In terms of function and basic

[8] The results shown in Figure 2 are not additive; in other words, the overall impact of simultaneously implementing all of the TIOs is less than and not the sum of the individual cost reductions.

description, a steam receiver is similar to a molten-salt receiver; however, steam receivers are a more mature technology than molten-salt receivers.

Table 3 identifies the costs associated with a typical molten-salt solar receiver system using a single tower. The cost of the receiver system is dominated by two components: the solar receiver (59%) and tower (21%). The calculations are based on the Utility Study plant since it is closer in size to the baseline plant.

As mentioned above, the Roadmap Workshop Baseline cost is a "rolled-up" value based primarily on responses obtained during the Roadmap Workshop. Whereas columns 1 and 2 are from single studies, column 3 represents a consolidated value from numerous individuals and organizations, which may explain the discrepancy in receiver costs. Furthermore, the discrepancy in receiver costs may also be attributable to different receiver sizes.

Table 3. Cost of solar receiver subsystem [$/kW$_t$] expressed in 2010 dollars

Receiver System Component	**Utility Studies 470 MW$_t$**	**Abengoa Study 910 MW$_t$**	**Roadmap Workshop Baseline**
Receiver	71	58	–
Tower	25	27	–
Riser/Downcomer	16	13	–
Cold Salt Pumps	6	7	–
Controls and Instruments	1	1	–
Spare Parts and Other Directs	1	3	–
Contingency	18	16	–
Total Capital Cost	**$138/kW$_t$**	**$125/kW$_t$**	**$200/kW$_t$**

3.2.2 Future Improvement Opportunities

Smaller and simpler receivers will result in higher efficiencies (due to reduced heat-loss area) and improved reliability. For advanced central receivers, this translates into a durable, high-temperature absorber (solar spectrum) with reduced thermal emissivity (infrared) that is capable of operating unprotected in ambient air conditions. Specific TIOs identified to achieve these design characteristics include:

- High thermal conversion efficiency and receiver materials database: One way to increase thermal-to-electric conversion efficiency is by interfacing a power tower with a supercritical Rankine cycle, which can be accomplished by raising the receiver outlet temperature to approximately 650°C. Thus, receiver tube materials that can reliably operate above 650°C with incident flux concentrations exceeding 1000 suns must be developed or identified, evaluated, and catalogued.

- Solar selective absorbers and coatings: Current receiver surfaces possess a high solar absorptivity but do not possess low infrared emissivity. New materials and formulations must be examined that exhibit the desired thermal/optical properties and are resistant to oxidation or degradation when operating in air. Thermal cycling testing is also required to ensure candidate materials can operate over a wide range of temperatures for many years.
- Receiver thermal loss and flux measurements: Characterization of thermal losses and incident fluxes for a thermal receiver will lead to optimized receiver designs. Thermal losses from a receiver are primarily the result of radiation and convection to the environment. A rotating flux mapper for characterizing the solar flux incident on the receiver is currently under development at Sandia, and other advanced measurement techniques are necessary to accurately characterize and evaluate receiver designs and optical surface characteristics at high temperatures.
- Steam receiver studies and optimization: Current steam receivers are based on mature steam boiler technology and designs. Further development of direct steam receivers can be achieved through studies, monitoring, and optimization of initial commercial steam-receiver power tower plants.
- Tall tower acceptance: Towers that exceed 100 meters in height are typically used in commercial power tower projects. As can be expected, public opinion of such tall structures is mixed; while some have a positive reaction to the aesthetics of power towers, others take a more negative view. The U.S. Air Force (USAF) has also expressed concern that power towers may encroach on their flight testing grounds in the desert Southwest. The USAF and DOE are working together to address these concerns. In addition, Sandia currently performs glint and glare studies and participates in public meetings to support power tower acceptance.

Figure 3 shows the potential impact of solar receiver cost reductions and performance improvements on LCOE. Results are based on the baseline model with individual parameters varied one at a time in SAM.[9]

[9] The results shown in Figure 3 are not additive; in other words, the overall impact of simultaneously implementing all of the TIOs is less than and not the sum of the individual cost reductions.

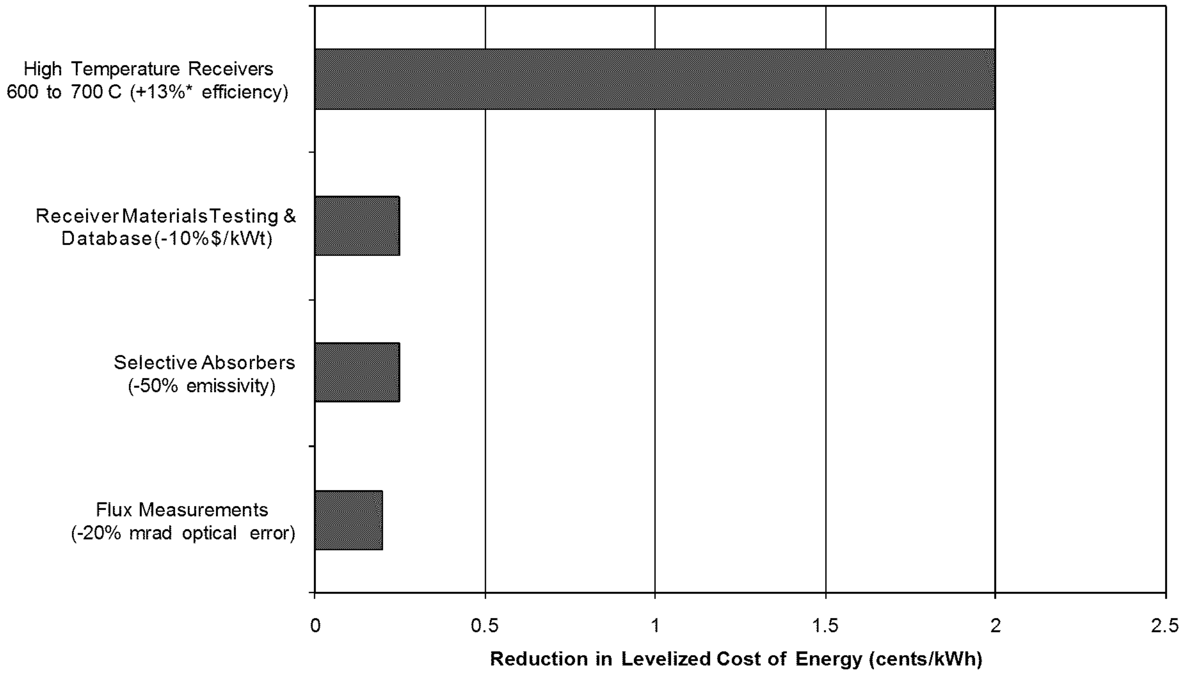

Figure 3. Potential impact of solar receiver cost reductions and performance improvements on LCOE (*absolute percentage improvement)

3.3. Thermal Energy Storage

3.3.1 Current Status

The 2-tank, sensible-heat molten-salt thermal storage system is the current state-of-the-art for power towers. This storage configuration was originally demonstrated at Solar Two and has been adapted for use in commercial trough systems deployed in Spain. As shown in Table 4, the cost of this type of storage system is dominated by two components: salt media (57%) and tanks (29%). The calculation is based on the Utility Study plant since it is closer in size to the baseline plant.

As mentioned above, the Roadmap Workshop Baseline cost is a "rolled-up" value based primarily on responses obtained during the Roadmap Workshop. Whereas columns 1 and 2 are from single studies, column 3 represents a consolidated value from numerous individuals and organizations, which may explain the discrepancy in storage costs. Furthermore, the discrepancy in storage costs may also be attributable to different storage sizes.

Table 4. Cost of thermal energy storage subsystem [$/kWh$_t$] expressed in 2010 dollars

Storage System Component	Utility Studies 1560 MWh	Abengoa Study 8140 MWh	Roadmap Workshop Baseline
Tanks	6	6	–
Foundations	0.7	1	–
Salt Media	12	11	–
Piping and Small Support Pumps	1	0.2	–
Controls and Instrumentation	0.5	0.1	–
Spare Parts and Other Directs	1	0.9	–
Contingency	4	3	–
Total Capital Cost	**$25/kWh$_t$**	**$22/kWh$_t$**	**$30/kWh$_t$**

3.3.2 Future Improvements Opportunities

In support of advanced heat transfer fluid and thermal storage research, a molten-salt component testing facility is currently under development at Sandia to test hardware at operating conditions. In addition, the DOE CSP Program is currently supporting multiple projects that are exploring a number of thermal storage techniques, including thermoclines, phase change materials, nanoparticle fluids, thermochemical and solid-state storage. Specific TIOs identified in the area of thermal energy storage include:

- Salt valves and other hardware: Valves and other flow-loop hardware need to be improved relative to the experience at Solar Two. There is a particular need for materials suitable for use as valve packing and flange gaskets, as well as for instrumentation (e.g. flow and pressure sensors) capable of operation in a high-temperature molten-salt environment. In addition, the melting of large volumes of salt during facility start-up, along with the NO_x emissions that can occur, is a significant challenge. Sandia will leverage its molten-salt test loop and high-temperature corrosion test facility to evaluate components under realistic conditions.
- High-temperature operation: Thermal storage cost is inversely proportional to the hot and cold temperature differential; in other words, as the temperature differential increases, the capital cost of the storage subsystem is reduced because of the increase in sensible heat capacity, which leads to a reduction in storage media volume and tank size. The baseline 2-tank, molten-salt storage system operates at temperatures of 565°C in the hot tank and 290°C in the cold tank. An increase in temperature to 650°C may be feasible with nitrate salts [8] but will necessitate the use of higher-temperature containment designs. Higher temperature storage also supports high-

efficiency power cycles.

- High-temperature, single tank thermal storage: Replacing the 2-tank storage approach with a 1-tank, thermocline system using liquids or particles has the potential to reduce the cost of the thermal energy storage subsystem. However, thermal ratcheting resulting in increased tank stresses (i.e. thermal cycling causing the thermocline inside the tank to slump, placing excessive pressure on the tank walls) is a serious challenge that must be resolved before the predicted cost reduction can be realized. This problem is exacerbated in power tower thermoclines due to the high temperature differential between the top and bottom of the tank (as high as 300°C). Potential solutions such as tank inserts or sloping tank walls, as well as new materials for fluids and tanks, must be sought.
- Advanced high temperature heat transfer fluids: Power towers can potentially operate at very high temperatures (>1000°C), but available, low-cost, non-exotic engineering materials are required to increase the practical upper temperature limit. These advanced heat transfer fluids will enable high-temperature receivers and high-efficiency power cycles.
- Storage systems for steam towers: Future direct steam power towers will likely include at least a few hours of thermal storage to increase the value of electricity produced and increase capacity factor. Many of the storage options for steam towers are similar to molten-salt towers; however, they must be specifically adapted for compatibility with a direct steam system. Prior research at Sandia has been devoted to studying a variety of storage options for DSG systems [9].

Figure 4 shows the potential impact of thermal energy storage cost reductions and performance improvements on LCOE. Results are based on the baseline model with individual parameters varied one at a time in SAM.[10]

[10] The results shown in Figure 4 are not additive; in other words, the overall impact of simultaneously implementing all of the TIOs is less than and not the sum of the individual cost reductions.

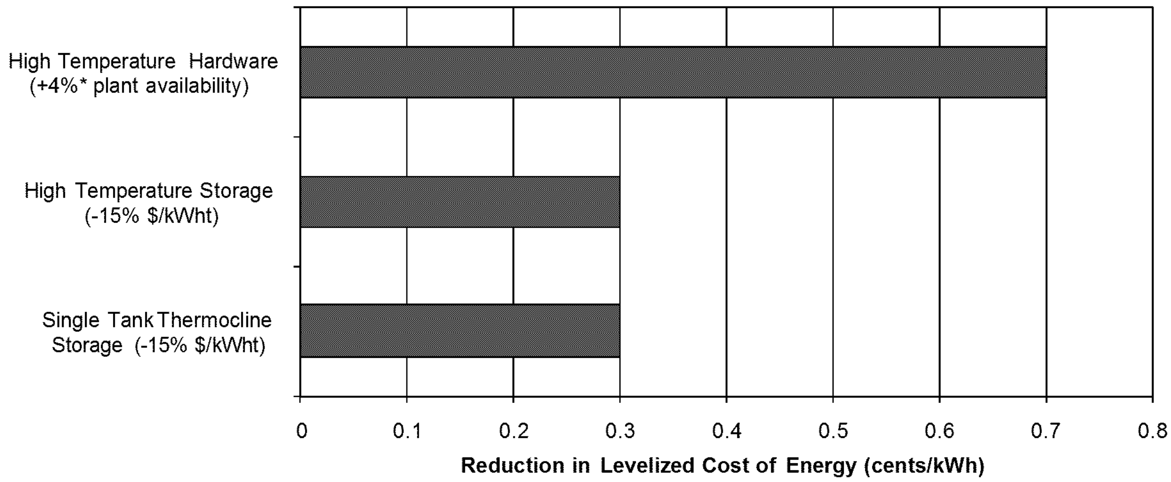

Figure 4. Potential impact of thermal energy storage cost reductions and performance improvements on LCOE (*absolute percentage improvement)

3.4. Power Block / Balance of Plant

3.4.1 Current Status

The current power tower power blocks used in both steam and molten-salt power tower designs have been promoted since the 1980s and utilize steam Rankine cycle components representative of a conventional fossil-fired plant. The baseline power block consists of a molten-salt steam generator that feeds a subcritical Rankine cycle with reheat. The inlet steam temperature is 540°C, and the turbine thermal-to-electric conversion efficiency is approximately 42% with a wet-cooled condenser [1]. While subcritical Rankine cycles are already commercially available in the 100-200 MW_e size range and employ conventional turbomachinary, the molten-salt steam generator is solar-specific hardware that has only been demonstrated at a relatively modest scale.

As shown in Table 5, the cost of the steam generator system is dominated by a single class of components: salt heat exchangers (85%). The calculation is based on the Utility Study plant since it is closest in size to the baseline plant.

As mentioned above, the Roadmap Workshop Baseline cost is a "rolled-up" value based primarily on responses obtained during the Roadmap Workshop. Whereas columns 1 and 2 are from single studies, column 3 represents a consolidated value from numerous individuals and organizations, which may explain the discrepancy in steam generator costs. Furthermore, the discrepancy in steam generator costs may also be attributable to different power block sizes.

Table 5. Cost of steam generator subsystem [$/kW$_e$] expressed in 2010 dollars

Steam Generator System Component	Utility Studies 100 MW$_e$ (260 MW$_t$)	Abengoa Study 400 MW$_e$ (1000 MW$_t$)	Roadmap Workshop Baseline
Heat Exchangers	214	110	–
Structures/Foundations	1	0.5	–
Piping	22	12	–
Hot Salt Pumps	10	12	–
Auxiliary Equipment	3	2	–
Spare Parts and Other Directs	1	9	–
Contingency	38	22	–
Total Capital Cost	**$290/kW$_e$**	**$168/kW$_e$**	**$250/kW$_e$**

3.4.2 Future Improvement Opportunities

Many of the issues surrounding the power block and balance of plant are non-solar in nature and are beyond the scope of the DOE CSP Program; however, "exceptions" do exist. TIOs identified during the Roadmap Workshop include:

- Advanced power cycles: Three advanced power cycles applicable to power towers — supercritical steam Rankine, high temperature air Brayton, and supercritical CO_2 Brayton — offer the potential to increase the efficiency of the power block to nearly 50% relative to today's subcritical steam Rankine cycle efficiency of 42%. The "next step" power cycle is likely supercritical steam Rankine since this cycle readily exists at commercial utility-scale fossil plants. However, existing systems are 400 MW$_e$ or larger and may need to be scaled down to better accommodate power tower systems.
- Parasitic power reduction: Parasitic power consumption at Solar One and Solar Two were relatively high. Although most of the consumption can be attributed to the small size of the plants, studies of proposed commercial-scale plants suggest that parasitics will consume 10% or more of the gross annual electricity. Receiver pumps are a major source of consumption, and thus head-recovery options should be explored to reduce their impact. A campaign to reduce plant-wide parasitics in early commercial plants should also be implemented.[11]
- Hybridization: A promising lower-cost market-entry strategy is augmentation of existing fossil-fired plants with power tower systems. Integration with existing natural-gas combined cycle and coal-fired plants is being studied by EPRI and the

[11] Simulations with SOLERGY suggest a 50/40/10 parasitics split between turbine plant/solar plant/offline sources for a baseload plant. For a peaking plant without storage, the parasitic split is approximately 20/30/50.

national laboratories, among others. Hybridization of power towers and existing fossil-fired plants holds several distinct advantages, including reduction in capital and O&M costs through the use of existing power block hardware and O&M crews, respectively. In addition, new "solar-only" power tower plants can benefit from a small amount of fossil backup to ensure dispatchability by increasing capacity factor.

- Dry cooling: Power towers are typically built in desert areas where water is a scarce resource. A standard power tower power block that employs wet cooling requires approximately 650 gallons of water to produce one megawatt-hour of solar electricity [10]. The issue of water use will likely require power towers to transition to dry or hybrid cooling; therefore, a dry cooling system that does not significantly reduce the efficiency of the power block is needed.
- Designs for rapid temperature change: Initial steam receiver power towers will not incorporate a thermal energy storage system. Thus, cloud transients affecting the solar receiver will rapidly impact the operation of the turbine generator. If cloud duration lasts more than a few minutes, steam conditions will degrade and the turbine generator may trip offline. When sun returns, the turbine must be able to quickly restart to mitigate energy losses. The inability to quickly restart the turbine at Solar One led to significant energy losses, and the problem is only intensified in commercial plants.

Figure 5 shows the potential impact of power block cost reductions and performance improvements on LCOE. Results are based on the baseline model with individual parameters varied one at a time in SAM.[12]

[12] The results shown in Figure 5 are not additive; in other words, the overall impact of simultaneously implementing all of the TIOs is less than and not the sum of the individual cost reductions.

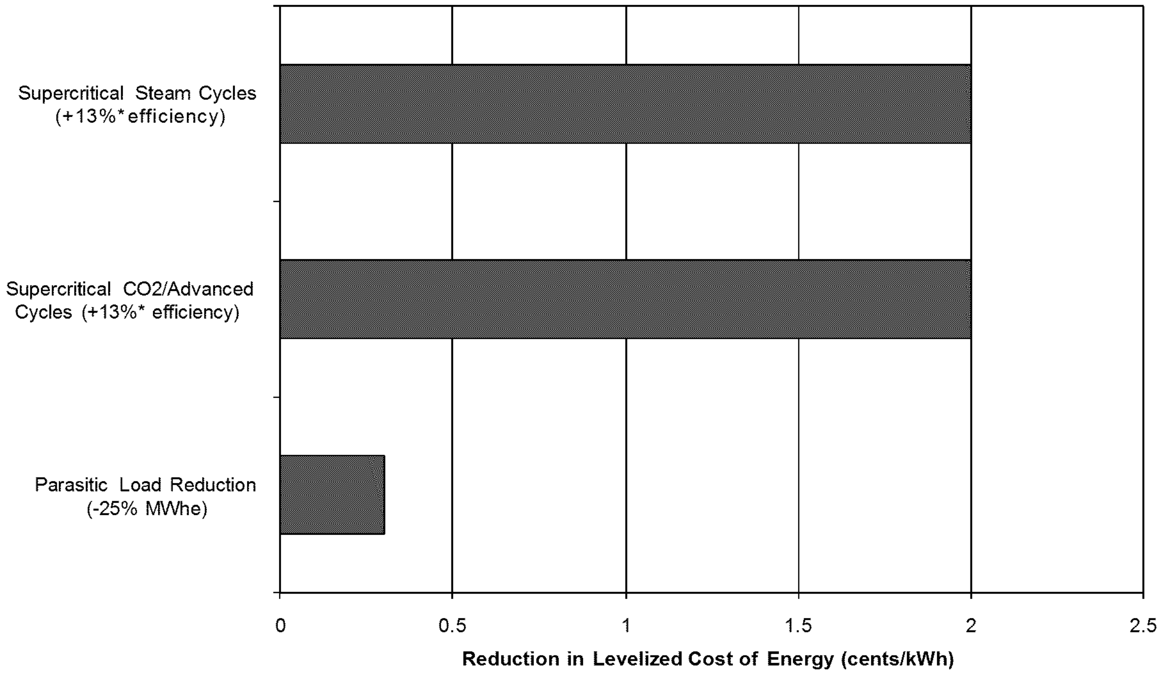

Figure 5. Potential impact of power block and balance of plant cost reductions and performance improvements on LCOE (*absolute percentage improvement)

3.5. Operation and Maintenance Costs

3.5.1 Current Status

Very little data exists on the annual O&M costs for power towers; the best data available to the DOE CSP Program is from Solar One, which operated in a daily power-production mode for approximately four years after the test and evaluation phase was completed. As time progressed at Solar One, fewer O&M personnel were required to maintain a high degree of plant availability.[13] During the final years of Solar One's operation, the SEGS I parabolic trough plant, located near Solar One, began its early phase of commercial operation. Both Solar One and SEGS I produced approximately 10 MW_e of solar power. Based on discussions between key staff from the two plants, it was discovered that the number of O&M staff required for a tower and trough plant is very similar. Thus, to a first order, O&M costs for towers and troughs should be comparable. Sandia worked with the SEGS III-VII trough plants (150 MW_e total) at Kramer Junction, CA throughout the 1990s to reduce O&M costs [9]. Table 6 shows estimated O&M costs for towers (columns 1, 2, and 4) and troughs (column 3).

As mentioned above, the Roadmap Workshop Baseline cost is a "rolled-up" value based primarily on responses obtained during the Roadmap Workshop. Whereas columns 1 and 2 are

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[13] The O&M staff numbered approximately 25 in the third year of operation, compared to 15 in the fourth year.

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from single studies, column 4 represents a consolidated value from numerous individuals and organizations, which may explain the discrepancy in O&M costs. Furthermore, the discrepancy in O&M costs may also be attributable to different plant sizes.

Table 6. Cost of O&M [$/kW-yr] expressed in 2010 dollars

	Utility Studies 100 MW_e	Abengoa Study 400 MW_e	Trough 150 MW_e	Roadmap Workshop Baseline
Annual O&M Costs	$87/kW-yr	$67/kW-yr	$100/kW-yr	$65/kW-yr

One reason for the discrepancy between the O&M costs shown for towers and troughs in Table 6 is that the 150 MW_e plant at Kramer Junction is actually composed of five 30 MW_e plants, each with its own turbine and operating crew. If the Kramer Junction facility had only one turbine and operating crew, O&M costs would likely be more in agreement with the tower values.

3.5.2 Future Improvement Opportunities

As the first commercial power towers come online in the USA, the actual O&M costs should be closely monitored, which in turn should lead to plant optimization and O&M cost reduction. As mentioned, the O&M costs of the SEGS plants at Kramer Junction were reduced through collaboration between the plant owner and DOE. The Kramer Junction SEGS plants initially experienced high O&M costs, and a joint project with DOE was established to address the problem. Over a six year period, O&M improvements were made in 28 technical areas, resulting in O&M LCOE cost reductions of over 35% [9]. Figure 6 shows the potential impact of O&M cost reductions and performance improvements on LCOE. Results are based on the baseline model with individual parameters varied one at a time in SAM.

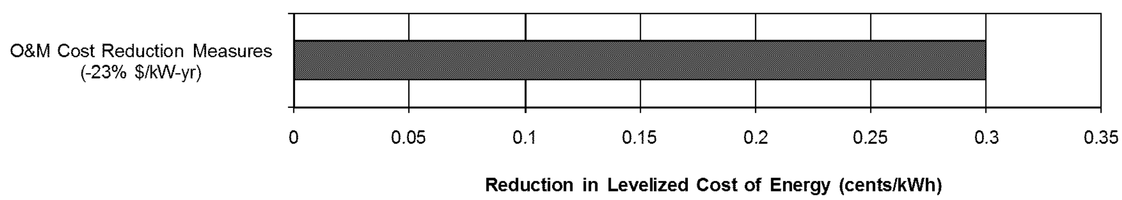


Figure 6. Potential impact of O&M cost reductions and performance improvements on LCOE

3.6. Summary of TIO Impacts

In summary, all four subsystems should be the focus of a cost reduction plan for power towers. The relative importance of each cost category can be identified using the percentage breakdowns described in the preceding sections, which is shown in Table 7. The top three capital-cost categories identified are 1) heliostat drives for both large and small heliostats; 2) receiver module; and 3) manufacturing facilities for both large and small heliostats. In Table 7, the percentages in column 3 result from the multiplication of the values in columns 1 and 2.

Table 7. Relative ranking of capital cost categories per subsystem[14]

Subsystem Impact on LCOE	Subsystem Capital Cost Breakdown	Total Relative Impact on LCOE
38% Large Heliostats	27% Drives	10.3%
	23% Manufacturing	8.7%
	22% Mirror Modules	8.4%
	19% Structure support	7.2%
38% Small Heliostats	30% Drives	11.4%
	23% Manufacturing	8.7%
	16% Mirror Modules	6.1%
	19% Field Wiring/Control	7.2%
19% Receiver System	59% Receiver Module	11.2%
	21% Tower	4.0%
13% Storage System	57% Salt media	7.4%
	29% Tanks	3.8%
7% Steam Generator	85% Salt Heat Exchangers	6.0%

Figure 7 summarizes the impact of the TIOs on LCOE. It is important to emphasize that each TIO was evaluated independently of the others, and therefore the incremental impact of each TIO on LCOE cannot be added together to determine the cumulative impact of all TIOs on the system LCOE.

[14] Only the most significant capital cost categories within each subsystem are shown. Thus, totals do not add to 100%.

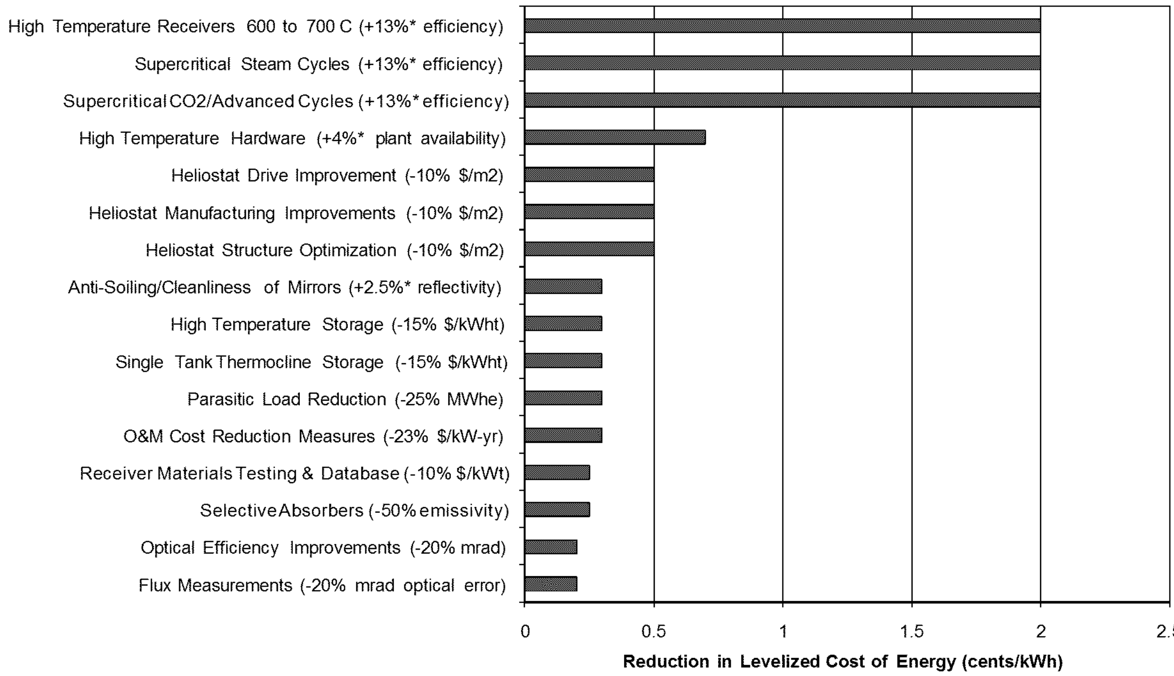


Figure 7. Potential impact of power tower cost reductions and performance improvements on LCOE (*absolute percentage improvement)

4. Recommended Activities and Spend Plan

In this section, specific potential activities to achieve the cost reductions outlined in this roadmap are listed. These activities are largely the product of the TIOs identified during the Roadmap Workshop. SAM simulations were used to estimate the impact of each activity on LCOE. Table 8Table 8, which served as an input into Figure 1, shows projected performance and cost improvement scenarios for years 2013 (improvements "in the pipeline"), 2017, and 2020. The year 2013 case is shown with both a 30% and 10% ITC.

Table 8. Projected performance and cost improvement scenarios

Power Tower Inputs	Case 1 2013 Sandia & Industry Studies	Case 1.1 2013 Sandia & Industry Studies	Comments on Case 2.1 Values	Case 2.1 2017	Comments on Case 3.1 Values	Case 3.1 2020
Design Assumptions:						
Turbine MWe (gross/net)	110/100	110/100		165/150		165/150
Receiver Outlet Temperature (degC)	565	565	Raise salt temperature	600	Raise salt temperature some more	650
Solar Multiple	2.1	2.1		2.6		2.9
Receiver Design Point Rating MWt	540	540		1000		1000
Thermal Storage hours	9	9		13		14
Investment Tax Credit	30%	10%		10%		10%
Cost/Performance Assumptions:						
System Availability	90	90	Learning	94		94
Turbine efficiency	0.425	0.425	Higher operating temperature gain is negated by switch to dry cooling	0.425	Switch to supercritical Rankine cycle	0.48
Heliostat reflectivity	0.935	0.935		0.95		0.95
Heliostat cleanliness	0.95	0.95		0.95		0.975
Heliostat image error (mrad)	1.53	1.53		1.31		1.25
Heliostat Field ($/m2)	200	200		170		120
Receiver emissivity	0.88	0.88		0.88	Selective surface	0.4
Receiver System ($/kWht)	200	200	Plant scale reduces cost	165	Optimized design	150
Thermal Storage ($/kWht)	30	30	Optimized 2 tank, higher temperature	25	Thermocline 1 tank, higher temperature	20
Steam Generator ($/kWe)	350	350	Plant scale reduces cost	300	Optimized design	250
Power Block ($/kWe)	1000	1000	Plant scale reduces cost	900	Optimized design	800
O&M ($/kW-yr)	65	65	Start O&M cost reduction project, plant scale	57	Complete O&M cost reduction project	50
EPC, Project, land (% of direct costs)	35	35		30	Modular plant, learning, lower project risk	25
Outputs						
Total Installed Cost ($/kW)	7427	7427		7403		5677
Debt Fraction (optimized)	41.1	54.2		54.2		54.1
Capacity factor	48.1	48.1		64.5		72
Annual Efficiency (Enet/Q_DNI*SF_area)	14.8%	14.8%		15.7%		17.8%
LCOE (c/kWh, real)	12.3	15.0		11.1		7.8
PPA Price (c/kWh, 1st year)	14.1	17.2		12.7		8.9
LCOE (c/kWh, nominal)	15.6	19.0		14		9.8

A potential multi-year task and spend plan for DOE-funded power tower R&D from FY12 through FY22 is shown in Table 9. Table 9 includes the following for each activity:

- the activity title,
- the activity participants,
- whether it is a new (N) or existing (E) activity,
- the relevant section of this plan to which the activity applies,
- the priority of the activity: high (H), medium (M), or low (L),
- an appropriate metric for the activity,
- the potential improvement in the metric,
- the potential impact of the activity on the levelized cost of electricity (LCOE),
- the time frame: Near, Mid, or Long Term,
- the recommended funding for each activity from FY12 through FY22, and
- a description of the activity.

It should be noted that each activity is individually evaluated; in reality there will be overlap in the contributions of the various activities to LCOE reduction, and thus the potential improvements in the metrics and LCOE cannot simply be added together. The identification of activities as high, medium, or low, as well as near, mid, or long term, was designated through a voting and ranking process during the Roadmap Workshop. *Only high and medium priority activities are displayed in Table 9*. The content of the multi-year task and spend plan in Table 9 is organized to aid DOE in allocating a finite budget. The plan will be periodically revisited and updated based on industry feedback, programmatic objectives, and budget allocations. It is important to recognize that not all activities in the plan are necessary to achieve the target cost goals; the purpose of the plan is to list the R&D options available, from which the activities that will have the highest impact can be selected.

Table 9. Potential multi-year activities and budgets for DOE-funded power tower R&D

AOP Power Tower R&D Activity	Participant(s)	New/ Exist	Plan ID Section	Priority	Metric	Metric Impact	LCOE Impact	Time-frame	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	Description
Heliostats									1650	2250	2450	1250	1050	600	600	400	400	400	400	
Drives	Sandia/Industry	N	3.1.2	H	$/m2	-10%	0.5 ¢/kWh	Near	500	750	750	100	100	100	100	0	0	0	0	Low-cost drive study in FY12. Build and test prototypes in FY13/14. Evauate new drives in commercial plants FY15 to 18.
Optical Methods and Testing	Sandia/NREL	E	3.1.2	H	optical error (mrad)	-20%	0.2 ¢/kWh	Near	200	200	200	200	200	200	200	200	200	200	200	Develop methods in early years. Apply methods to optimize commercial plants in later years.
Wind Loads Measurement and Mitigation	Sandia/NREL	E	3.1.2	H	$/m2	-10%	0.5 ¢/kWh	Near/Mid	250	250	250	250	250	0	0	0	0	0	0	Develop methods and demonstrate on NSTTF heliostats in FY12/13. Measure wind loads at commercial plants FY15/16.
Manufacturing FOA	Sandia/Industry	N	3.1.2	M	$/m2	-10%	0.5 ¢/kWh	Near	500	750	750	200	200	0	0	0	0	0	0	Manfacturing study in FY12. Cost-shared upgrade of manufacturing plant in FY13/14. Optimization of manufacturing process in FY15/16.
Anti-Soiling/Cleaning of Mirrors	NREL/Industry	N	3.1.2	M	Cleanliness	2.5%	0.3 ¢/kWh	Near/Mid	0	100	300	300	100	100	100	0	0	0	0	Evaluation of existing anti-soiling products in FY13. Adapt product for solar application in FY14/15. Evaluate improved product in commercial plants FY16 to 18.
Basic Structure Optimization	Sandia/Industry	E	3.1.2	M	$/m2	-10%	0.5 ¢/kWh	Mid	200	200	200	200	200	200	200	200	200	200	200	Perform CFD analysis of industry heliostats and recommend design improvements
Receiver System									750	1200	2300	5300	2300	2200	2700	1700	1700	1700	1700	
Receiver Materials Testing & Database	Sandia	N	3.2.2	H	$/kWt	-10%	0.25 ¢/kWh	Near/Mid	200	200	200	200	200	200	200	0	0	0	0	Recommend and test receiver materials
Steam Receivers and Hybrid	Sandia/Industry	N	3.2.2	H	Plant Availability	4%	Note 1	Near/Mid	0	100	300	300	300	300	0	0	0	0	0	Work with industry to solve steam-receiver problems that occur at initial commercial plants
Selective Absorbers	Sandia/NREL	E	3.2.2	H	Emissivity	-50%	0.25 ¢/kWh	Mid	200	200	200	200	200	200	1000	200	200	200	200	Continue to develop low-emmissivity coating for central receiver application from FY12-17. Implement a test panel at commercial plant in FY18. Evaluate test panel and improve FY19-22.
High Temperature Receivers (600 to 700 C)	Sandia/Industry	E	3.2.2	H	Thermal-to-Electric Conversion Efficiency	13%	2 ¢/kWh	Mid/Long	150	500	1000	4000	1500	1500	1500	1500	1500	1500	1500	Complete studies to identify preferred next-generation high temperature receivers in FY12 to 14. Upgrade current <600 C test facility to operate up to 650 C in FY15. Through cost-shared projects, build and test next generation high temperature receiver concepts of interest to industry FY16-22.
Flux Measurements	Sandia/Industry	E	3.2.2	M	optical error (mrad)	-20%	0.2 ¢/kWh	Near	100	100	500	500	0	0	0	0	0	0	0	Complete the development and testing of Sandia's receiver flux monitor in FY12/13. Through cost-shared project(s), implement a commercial scale device at existing plant(s) in FY14/15.
Tall Tower Acceptance	Sandia	E	3.2.2	M	Public Acceptance	N/A		Mid	100	100	100	100	100		0	0	0	0	0	Continue to perform glint/glare studies and participate in legal proceedings that are important to acquiring an operating permit for commercial tower plants.
Thermal Storage System									1000	1000	1500	6000	1800	6300	1800	1800	1800	1300	1300	
High Temperature Storage	Sandia	N	3.3.2	H	$/kWht	-15%	0.3 ¢/kWh	Mid/Long	0	0	500	5000	500	500	500	500	500	500	500	Perform study in FY14 to identify preferred high-temperature storage to interface with preferred high-temperature receiver identified in FY12-13. Build a multi MWt storage test facility in FY15. Operate and maintain high temperature storage test facility FY16-FY22.
Valves and Non-Welded Flanges	Sandia	E	3.3.2	M	Plant Availability	4%	0.7 ¢/kWh	Near/Mid	500	500	500	500	500	500	500	500	500	500	500	Test valves/components to be used in <600 C towers from FY12-FY15. After FY15, test components for applications up to 650 C.
Single Tank Thermocline Storage	Sandia/University	E	3.3.2	M	$/kWht	-15%	0.3 ¢/kWh	Mid	200	200	200	200	500	5000	500	500	500	0	0	Perform small scales tests at U of Arizona or Purdue to resolve thermal ratcheting and thermocline performance issues from FY12 to 15. Design a multi-MW thermocline system in FY16 and build it in FY17. Test it from FY18-20.
Alternative Fluids at 700 C+	Sandia/NREL	N	3.3.2	M	$/kWht	?		Mid/Long	300	300	300	300	300	300	300	300	300	300	300	Perform basic research on >700 C fluids for power tower application
Power Block/BOP									250	225	375	1000	700	650	550	100	100	100	100	
Low-Water Cooling	NREL/Sandia	N	3.4.2	H	gal/MWh water usage	-75%		Near/Mid	50	25	25	0	0	0	0	0	0	0	0	NREL is leading this effort, as described in Trough Roadmap.
Hi-Efficiency Hybrid Configurations	Industry/Sandia/NREL	E	3.4.2	H	$/kWe	-25%	3 ¢/kWh	Near/Mid	50	50	50	50	50	0	0	0	0	0	0	EPRI and others in industry are studying hybrid solar plants. Sandia/NREL are participating in these studies.
Designs for Rapid Temperature Change	Sandia/Industry	N	3.4.2	M	Annual Efficiency	1pt	Note 1	Near/Mid	0	0	50	300	0	0	0	0	0	0	0	Steam towers need a power block that can rapidly change temperature. In FY14 assess this ability within initial commercial steam towers. If a problem, perform study in FY15 to recommend design changes.
Parasitic Load Reduction	Sandia/Industry	N	3.4.2	M	MWhre	-25%	0.3 ¢/kWh	Near/Mid	0	0	100	100	100	100	0	0	0	0	0	Study the parasitic consumption in early commercial plants and recommend changes to design/operation to reduce parasitics.
Supercritical Steam Cycles	Sandia/Industry	E	3.4.2	M	Thermal-to-Electric Conversion Efficiency	13%	2 ¢/kWh	Mid/Long	100	100	100	500	500	500	500	50	50	50	50	Establish subcontracts with turbine suppliers to investigate feasibility of scaling down today's 450 MWe turbine to ~150 MWe for tower application. Design/build solar-specific hardware FY15-18.
Supercritical CO2/Advanced Cycles	Sandia/NREL	E	3.4.2	M	Thermal-to-Electric Conversion Efficiency	13%	2 ¢/kWh	Long	50	50	50	50	50	50	50	50	50	50	50	Keep abreast of advanced alternate power blocks being developed by others. If supercritical steam is no longer preferred, use Supercritical Steam cycle budget to pursue alternate power block.
O&M Cost Reduction									0	100	100	1100	1100	1100	1100	1100	1100	1100	1100	
O&M Analysis of Initial Commercial Plants	Industry/Sandia/NREL	N	3.5.2	H Note 2	$/kW-yr			Near	0	100	100	100	100	100	100	100	100	100	100	Forge relationships with commercial power tower projects and analyze O&M costs.
O&M Cost Reduction Measures	Industry/Sandia/NREL	N	3.5.2	H Note 2	$/kW-yr	-23%	0.3 ¢/kWh	Near	0	0	0	1000	1000	1000	1000	1000	1000	1000	1000	Results of O&M cost analysis will be used to define cost-shared O&M cost reduction and reliability improvement programs.
FOA Support									50	50	0	0	0	0	0	0	0	0	0	
Baseload FOA Support	Industry/Sandia/NREL	E	5		Plant LCOE	-20%	Note 1	Near	50	50	0	0	0	0	0	0	0	0	0	Review ongoing Baseload FOA project
TOTALS									3700	4825	6725	14650	6950	10850	6750	5100	5100	4600	4600	

Note 1: The improvement in this metric assumes the base case power tower is a steam receiver without storage. Base case LCOEs have not been calculated for this type of power tower.
Note 2: Plant-wide O&M cost reduction was not discussed during the Roadmap Workshop. Sandia believes this is an important activity based on our experience with early commercial trough projects.

5. Power Towers and the SunShot Initiative

On February 4, 2011, United States Secretary of Energy Steven Chu officially unveiled the U.S. Department of Energy's SunShot Initiative, an aggressive R&D plan to make large-scale solar energy systems cost competitive without subsidies by 2020. The SunShot Initiative takes a systems-level approach to revolutionary, disruptive (as opposed to incremental) technological advancements in the field of solar energy. The overarching goal of the SunShot Initiative is reaching cost parity with baseload energy rates, estimated to be 5-6¢/kWh without subsidies, which would pave the way for rapid and large-scale adoption of solar electricity across the United States.

For the SunShot Initiative, CSP provides the following benefits:

- *Thermal Energy Storage*: CSP offers a firm, dispatchable solar solution to meet utility demand for power, offsetting some of the intermittency and ramp-rate issues surrounding PV.
- *Hybridization*: Combined with thermal storage, a small amount of natural gas hybridization in a CSP plant can increase capacity to 75-85%, which would allow CSP to displace conventional (e.g. fossil) power plants.
- *Supply Chain*: The CSP supply chain is overwhelmingly domestic, from materials to manufacturing, including significant domestic job creation. Most, if not all, materials necessary to build a CSP plant can be found in the US.
- *Plant Size*: The size of utility-scale CSP facilities is consistent with the SunShot goal of large-scale solar installations. Two CSP plants (BrightSource Energy's Ivanpah and Abengoa Solar's Solana) currently under construction in the U.S. will be the largest and second largest solar plants in the world.

The SunShot Initiative goal for CSP is 6¢/kWh or less. While many of the TIOs identified in this roadmap are applicable to the SunShot cost reduction goal, it is clear that an "extra step" is necessary to move from the power tower roadmap projections — 7.8¢/kWh with a 10% ITC (or 8.6¢/kWh with a 0% ITC) — to the SunShot Initiative goal of 6¢/kWh with no ITC (as shown in Figure 8). Therefore, the DOE CSP Program is currently in the process of defining a corresponding R&D path forward. SunShot-level cost reductions for power towers likely includes an increase in system efficiency by moving to higher temperature operation (i.e. maximize conversion efficiency) without sacrificing efficiency elsewhere in the system (i.e. minimize collection efficiency losses). Likewise, reducing the cost of the solar field and developing high-temperature storage compatible with high-efficiency, high-temperature power cycles are critical to driving costs down.

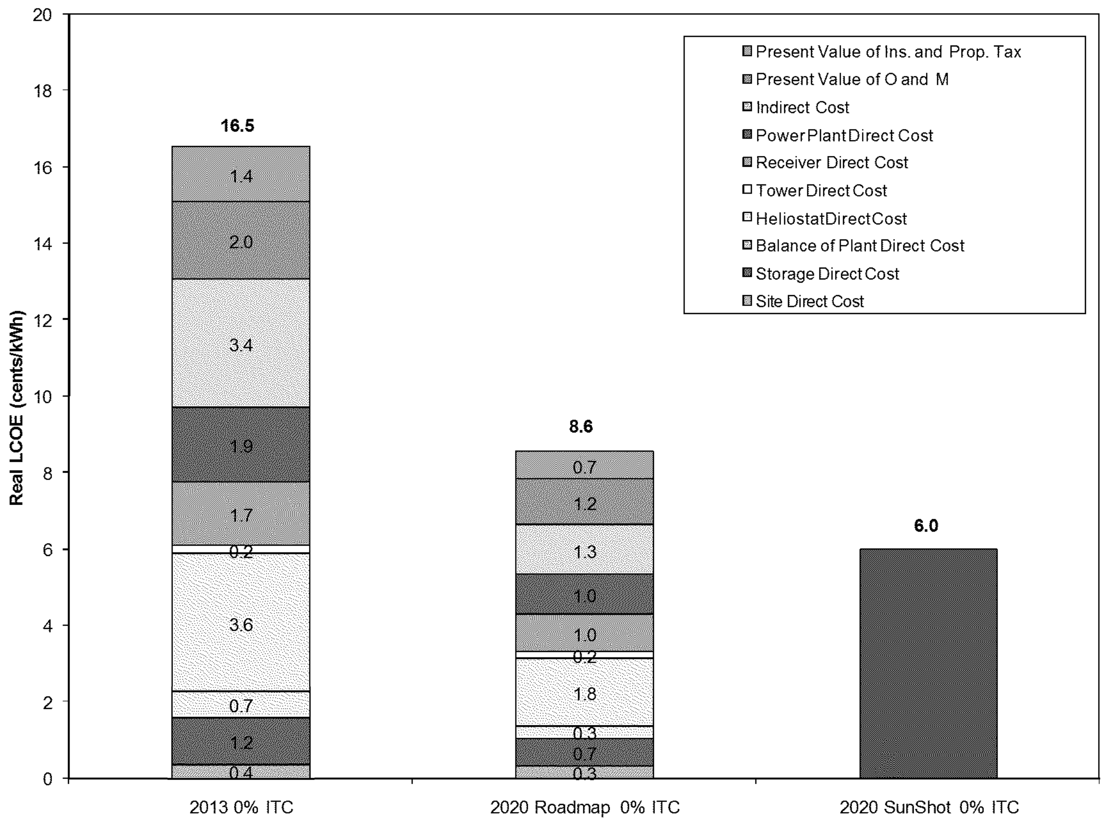


Figure 8. LCOE reduction (real 2010 dollars) pathway to SunShot Initiative goal (all cases are shown with a 0% ITC)

Based on industry comments, including a DOE-CSP Industry Meeting held in conjunction with SEIA on March 8-9, 2011 in Arlington, VA, the following list outlines TIOs in addition to those already mentioned that could potentially lead to SunShot-level cost reductions for power towers.

Solar Collector Field

- Alternative heliostat designs that use significantly less material.
- Non-steel-based support structures.
- Reliable wireless methods for heliostat power and communication.
- Advanced, self-aligning control systems.
- Closed-loop tracking.
- Curved heliostat facet optimization.
- Low-profile heliostats that are subject to less wind-loading.
- Utilization of secondary concentrator designs with improved optics.
- Automatic soiling detection and reflectivity assessment.

- Driven-pylon or ground-mounted pedestals.
- Minimal field grading and site preparation.
- Increase in volume production.

Solar Receiver

- High-temperature materials capable of reliable operation over many thermal cycles.
- Cavity receiver designs or other alternative concepts (e.g. particle, beam down, volumetric, modular) that enable efficient solar collection at high temperature.
- Appropriate models to simulate receiver performance at part-load conditions.
- Coverings for receiver designs that employ quartz windows.
- Integration of the tower as a container for the thermal energy storage system.
- For modular designs, lightweight towers that can be rapidly assembled and installed.

Thermal Energy Storage

- High-temperature storage concepts with enhanced thermal stability and increased storage density, such as novel inorganic liquids, solid particles, phase change materials, or thermochemical approaches.
- Additives that augment the heat capacity of existing fluids such as 60% $NaNO_3$ / 40% KNO_3 solar salt.
- Non-nitrate salts capable of operation at higher temperatures.
- Lightweight, compact thermal storage systems that could potentially be integrated with the tower (located within or on top).

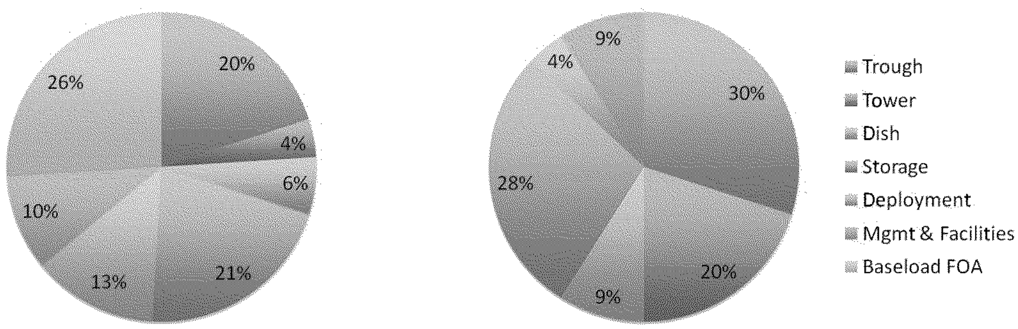
Power Block / Balance of Plant

- Advanced power cycles "beyond" supercritical steam, such as supercritical CO_2 or air Brayton.
- Industrial micro-turbines that lead to reduced turbomachinery size and cost.
- Combined-cycle power systems that lead to higher efficiency cycles.
- Development of high-temperature metal or ceramic heat exchangers that are compatible with advanced power cycles.
- Corrosive-resistant hardware (e.g. piping, structure, valves, valve packing, flanges, ducting, blowers, dampers, insulation, pressure and flow measurement devices) that can reliably operate at elevated temperatures.
- Efficient absorption chilling systems to cool compressor inlet for gas turbines.

- Modular plant designs that can be replicated and combined to create larger systems.
- Non-electricity applications (e.g. solar fuels, desalination, cogeneration, enhanced oil recovery).

6. Conclusions

Since the inception of the Power Tower Technology Roadmap, the DOE CSP Program budget distribution has significantly shifted to include an increased emphasis on advanced R&D and power towers. This is primarily due to the selection and funding of a group of CSP industry projects that are evaluating and designing complete power tower baseload systems. As Figure 9 shows, power towers jumped from 4% to 20% of total DOE CSP budget as a result of the Baseload Funding Opportunity Announcement (FOA) solicitation project awards.



(a) **(b)**

Figure 9. 2010 DOE CSP budget activity levels ($49.7M USD) (a) before and (b) after the Baseload FOA project award announcements [12]

Moving forward, it is anticipated that power tower R&D will continue to receive funding through competitive solicitations to industry and universities, as well as through activities at the national laboratories. During this ramp-up phase for power towers within the DOE CSP Program, the Power Tower Technology Roadmap will continue to be utilized as a tool to guide DOE towards those tasks that will create the most benefit and have the highest impact on reducing the cost of power tower systems.

Reducing the cost of power tower systems by up to 75% by the end of the decade is clearly a significant challenge; however, pursuing these aggressive goals will enable considerable advancements in power tower technology. This roadmap has outlined multiple pathways to achieve these ambitious cost reduction targets. DOE is poised to work alongside industry to make power towers competitive with fossil fuels through both technology activities (e.g. RDD&D, modeling, studies, testing) and non-technology activities (e.g. manufacturing, transmission, land, permitting, financing).

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ATTACHMENT 15

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Learning rates for energy technologies

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Abstract

Technological learning, i.e., cost reductions as technology manufacturers accumulate experience, is increasingly being incorporated in models to assess long-term energy strategies and related greenhouse gas emissions. Most of these applications use learning rates based on studies of non-energy technologies, or sparse results from a few energy studies. This report is a step towards a larger empirical basis for choosing learning rates (or learning rate distributions) of energy conversion technologies for energy models. We assemble data on experience accumulation and cost reductions for a number of energy technologies, estimate learning rates for the resulting 26 data sets, analyze their variability, and evaluate their usefulness for applications in long-term energy models.

For many products and services, unit costs decrease with increasing experience. The idealized pattern describing this kind of technological progress in a regular fashion is referred to as a learning curve, progress curve, experience curve, or learning by doing (Dutton and Thomas, 1984; Argote and Epple, 1990; Argote, 1999). In its most common formulation, unit costs decrease by a constant percentage, called the learning rate, for each doubling of experience.

Because experience accumulates with time, unit costs for a given technology thus decrease with time. Early modeling e!orts therefore approximated non-linear learning curves by simple time series in an e!ort to avoid computational and methodological di$culties. Modelers have speci"ed cost reductions over time both for individual energy technologies (Capros and Vouyoukas, 1999; Nakićenović *et al.*, 1998), and for groups (clusters) of similar technologies (Yohe, 1996; IEA-ETSAP, 1999).

When models in which costs decrease only as a function of time are used to compare alternative greenhouse gas (GHG) emission reduction strategies, they generally favor strategies that delay such reductions (Wigley *et al.*, 1996). This is so because the long-term atmospheric concentration of CO_2 depends mainly on cumulative CO_2 emissions (Houghton *et al.*, 1996). Thus, for a given concentration target, it makes no di!erence whether carbon reductions are early or delayed, and delayed reductions are cheaper. The models therefore tend to recommend delay.

For most products and services, however, it is not the passage of time that leads to cost reductions, but the accumulation of experience. Unlike a "ne wine, a technology design that is left on the shelf does not become better the longer it sits unused. Indeed, interruptions in production and use can cause experience to be lost and unit costs to rise, i.e., `forgetting by not doing' in contrast to learning by doing. Therefore, a number of initiatives are underway to incorporate into energy models technological cost reductions, not as functions of time, but as explicit functions of experience, i.e., as learning curves (Messner, 1997; Mattsson, 1997; EIA/DOE, 1999; Goulder and Mathai, 2000; Grübler and Gritsevskii, 2000). Such a formulation introduces in the models both non-linearities and positive feedbacks (the more a technology is used, the greater the incentive for using it more). This drastically increases model complexity and problematic non-convexities, both of which result in large computational requirements. But progress in modeling and computer performance is rapid, and if the new methods are to produce sensible and useful results, good estimates of technological learning rates will be needed as model input.

The importance of good (reliable) learning rate estimates is shown in Fig. 1. Using illustrative, but realistic,

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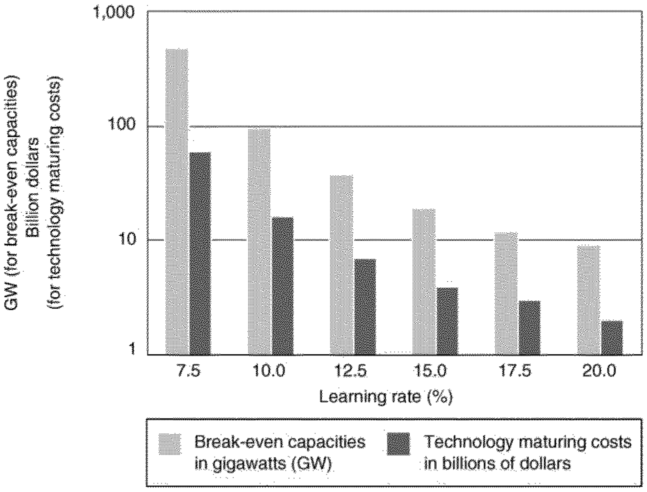

Fig. 1. Sensitivity of break-even capacities and technology maturing costs to learning rate variations.

values, Fig. 1 presents a hypothetical new technology with an initial unit cost of $2000kW~1 and a "xed `competitive cost targeta of $1000kW~1. The left bars represent break-even capacities for a new technology at di!erent assumed learning rates, where the break-even capacity is de"ned as the capacity additions needed to driveunitcostsdowntothe "xedcompetitivecosttarget. Theright barsarethe technologymaturingcosts,or the investments * over and above the competitivecost target * needed for the break-even capacity additions. Becausethe vertical axisof Fig. 1 is logarithmicand the horizontal axis is linear, the "gure shows that with decreasing learning rates, technology maturing costs and break-even capacities grow faster than exponentially. For our hypothetical new technology, decreasing the learningratefrom20to10% wouldincreasetechnology maturing costs from $2 billion to $16 billion, and the break-even capacity from 9 to 96GW.

Such high, non-linear sensitivity to learning rate variationsemphasizesthevalueof, "rst,reliablelearningrate estimatesasinputsand,second,stochasticmodelformulationsthatcanexplicitlycalculatetheimpactofremaining learning rate uncertainties on the eventual model results.

As a step in the direction of reliable estimates of energy-related learning rates, and their uncertainties, this paperassemblesdataforavarietyofenergytechnologies (fromnaturalgaspipelinestosub-componentsofend-use technologies),estimatestheimpliedlearningrates,checks howwellthedata "ttheclassiclearningcurvemodel,and draws conclusions about incorporating the resulting learning rates in energy models. Table 1 summarizes 26 datasetsandtheirestimatedlearningratesassumingthat cost reductions are a function only of the experience measure speci"ed in the table. Table 1 also gives the correlation coe$cients ($R2$)1, the measures of technological improvement used in the di!erent cases, and the measures of experience. For comparison, Table 2 lists additional energy-related learning rates that we have collectedor calculatedfrom the literature,but for which the original data sets are not available for our own analysis.

The "rst important feature of Tables 1 and 2 is the range of the estimated learning rates across the energy technologies. The range from Table 1 is illustrated as a histogram in the left panel of Fig. 2. For comparison, therightpanelshowstheresultsofDuttonandThomas ' (1984) compilation of over 100 studies of learning rates (not restricted to energy technologies) at the level of individual manufacturing "rms. The ranges of learning rates in both panels of Fig. 2 are comparable, and the median value of 16}17% for energy technologies is not far below the 19}20% median for the manufacturing "rms. This suggests that learning rates (and their variations)fromstudiesnotrestrictedtoenergytechnologies areusefulstarting pointsforenergymodelersuntilmore detailed studies of energy technologies are available.

To shed light on the reliability of the estimated learning rates, Table 1 also shows the correlation coe$cients ($R2$) for the estimated learning rates, and the second important feature of the table is the range of values for $R2$.Valuesrangefromverygood(0.99for Harmon 'sdata on solar PV modules) to very bad. Moreover, there can bemorevariabilitywithinagivendatasetthanmightbe suggested by a high $R2$ value. As an example, consider Harmon's data on PV modules as presented in Fig. 3. Theleftpartofthe "gure "tsalearningcurvetothedata, yieldinganestimatedlearningrateof20%.The "tlooks impressive,and,asjustnoted, $R2$ equals0.99.Butonthe right of Fig. 3, we still "nd considerable variety in the data set. This part of the "gure shows all learning rates that can be calculated from any two points in the data set, as follows. Consider "rst the curve labeled `1968a (the "rstlabelinthelegendbox).Thiscurvedescribesthe learningratesbetween1968andtheyeardescribedbythe value on the horizontal axis. Taken together, the curves on the right of Fig. 3 seem to show more variability withinthedatathanisevidentfromtheestimatedlearning curve on the left, and indicate how much calculated learningratesdependonthedatapointsthatarechosen. Giventhatthe bulkof thecalculatedlearningrates with end points in the last 15 years fall between 18 and 25%, theoverall learningrate of 20% shown in Table 1 looks reasonable, but the right-hand side of Fig. 3 suggests an energy modeler might want to incorporate more

1 The correlation coe$cientisa real numberbetween0and1 (inclusively).Itexpressesthequalityofthe "tbetweenthelearningcurvemodel andthedata.Theextremevaluesof0and1re #ect `nocorrelation a (or no explanatory value of the postulated formula) and `perfect correlationa (complete explanation by the postulated formula), respectively.

Table 1
Estimated energy-related learning rates!

Technology	Country/region	Time period	Estimated learning rate (%)	R^2 "	Performance measure (dependent variable)	Experience measure (independent variable)	Reference/data source
Oil extraction	North Sea	*	+ 25	*	sp. labor (man-hrs to construct one ton of platform jacket)	cum. cap. (construction projects)	Blackwood (1997)
Gas pipelines, onshore	US	1984}1997	3.7	0.09	sp. inv. price ($/mile-inch2)	cum. cap. (mile-inch2)	Zhao (1999)
Gas pipelines, o! shore	US	1984}1997	24	0.76	sp. inv. price ($/mile-inch2)	cum. cap. (mile-inch2)	Zhao (1999)
DC converters	World	1976}1994	37	0.35	conversion losses (%)	cum. cap. (installed units)	Rabitsch (1999)
Gas turbines	World#	1958}1963	22	}	sp. inv. cost ($/kW)	cum. cap. (MW)	MacGregor *et al.* (1991)
Gas turbines	World#	1963}1980	9.9	}	sp. inv. cost ($/kW)	cum. cap. (MW)	MacGregor *et al.* (1991)
Gas turbines	World#	1958}1980	13	0.94	sp. inv. cost ($/kW)	cum. cap. (MW)	NakicenovicH *et al.* (1998); MacGregor *et al.* (1991)
Nuclear power plants	OECD	1975}1993	5.8	0.95	sp. inv. cost ($/kW)	cum. cap. (MW)	Kouvaritakis *et al.* (2000)
Hydropower plants	OECD	1975}1993	1.4	0.89	sp. inv. cost ($/kW)	cum. cap. (MW)	Kouvaritakis *et al.* (2000)
Coal power plants	OECD	1975}1993	7.6	0.90	sp. inv. cost ($/kW)	cum. cap. (MW)	Kouvaritakis *et al.* (2000)
Lignite power plants	OECD	1975}1992	8.6	0.96	sp. inv. cost ($/kW)	cum. cap. (MW)	Kouvaritakis *et al.* (2000)
GTCC power plants	OECD	1984}1994	34	0.78	sp. inv. cost ($/kW)	cum. cap. (MW)	Kouvaritakis *et al.* (2000)
GTCC power plants	World	1981}1991	! 11$	0.41	sp. inv. price ($/kW)	cum. cap. (MW)	Claeson (1999)
GTCC power plants	World	1991}1997	26$	0.90	sp. inv. price ($/kW)	cum. cap. (MW)	Claeson (1999)
Wind power plants	OECD	1981}1995	17	0.94	sp. inv. cost ($/kW)	cum. cap. (MW)	Kouvaritakis *et al.* (2000)
Wind power (electricity)	California	1980}1994	18	0.85	sp. prod. cost ($/kWh)	cum. prod. (TWh)	CEC (1997); Loiter and Norberg-Bohm (1999)
Wind	Germany	1990}1998	8	0.95	sp. inv. price ($/kW)	cum. cap. (MW)	Durstewitz (1999)
Wind turbines	Denmark	1982}1997	8	n.a.	sp. inv. price ($/kW)	cum. cap. (MW)	Neij (1999)
Solar PV modules%	World	1968}1998	20	0.99	sp. inv. price ($/W1%)	cum. cap. (MW)	Harmon (2000)
Solar PV panels	US	1959}1974	22	0.94	sp. sale price ($/W1%)	cum. cap. (MW)	Maycock and Wake"eld (1975)
Ethanol	Brazil	1979}1995	20	0.89	sp. sale price ($/boe)	cum. prod. (cubic meters)	Goldemberg (1996)
Model-T ford	US	1909}1918	14	0.96	sale price ($ per car)	cum. prod. (cars)	Lipman and Sperling (1999); Abernathy and Wayne (1974)
Compact #uorescent lamps, integral-electronic type	US	1992}1998	16	0.66	sp. sale price ($ per lumen)	cum. prod. (units)	Iwafune (2000)
Air conditioners	Japan	1972}1997	10	0.82	sale price (Yen per unit)	cum. sales (units)	Akisawa (2000)
4-function pocket calculators	US	Early 1970s	30	n. a.	sale price ($ per unit)	cum. prod. (units)	Maycock and Wake"eld (1975)
SONY laser diodes	*	1982}1994	23	0.95	prod. cost (Yen per unit)	cum. prod. (units)	Lipman and Sperling (1999)

!Note: sp."speci"c; inv."investment; cum."cumulative; cap."capacity; prod."production.
"Two cautions are in order concerning values for R^2. For each line in the table, R^2 expresses the quality of the "t between the data and the estimated learning curve. However, R^2 values in di!erent lines should not be compared because sample sizes are di!erent. Second, R^2 measures the correlation for a straight line "t to the logarithms of the dependent and independent variables. As linear regression minimizes the sum of error squares, this means that relative rather than absolute errors are minimized.
#The geographical scope of the data is not reported explicitly. The context suggests it is the whole world.
$Note that these learning rates are based on prices, and one explanation of the negative 1981}1991 `learninga rate could be oligopolistic pricing behavior.
%Based on preliminary data.

Table 2
Reported energy-related learning rates!

Technology	Country/ region	Time period	Estimated learning rate (%)	Performance measure (dependent variable)	Experience measure (independent variable)	Reference/data source
Retail gasoline processing	US	1919}1969	20	sp. prod. cost ($/bbl)	cum. prod. (bbl)	Fisher (1974)
Crude oil at the well	US	1869}1971	5	sale price ($/bbl)	cum. prod. (bbl)	Fisher (1974)
Coal for electric utilities	US	1948}1969	25	sale price to utility ($/ton)	cum. prod. (tons)	Fisher (1974)
Electric power production	US	1926}1970	25	sale price ($/kWh)	cum. prod. (kWh)	Fisher (1974)
Solar PV	EU	1985}1995	35	sp. prod. cost (ECU/kWh)	cum. prod. (TWh)	IEA (2000)
Wind power	US	1985}1994	32	sp. prod. cost ($/kWh)	cum. prod. (TWh)	IEA (2000)
Wind power	EU	1980}1995	18	sp. prod. cost ($/kWh)	cum. prod. (TWh)	IEA (2000)
Wind power	Germany	1990}1998	8	sp. inv. price ($/kW)	cum. cap. (MW)	IEA (2000)
Wind power	Denmark	1982}1997	4"	sp. inv. price ($/kW)	cum. cap. (MW)	IEA (2000)
Electricity from biomass	EU	1980}1995	15	sp. prod. cost ($/kWh)	cum. prod. (TWh)	IEA (2000)
Supercritical coal	US	n.a.	3	sp. prod. cost ($/kWh)	cum. prod. (TWh)	IEA (2000); Joskow and Rose (1985)
GTCC	EU	n.a.	4	sp. prod. cost ($/kWh)	cum. prod. (TWh)	IEA (2000); Claeson (1999)
Solar PV modules	World	1976}1992	18	sale price ($/W$_{pd}$)	cum. sales (MW)	IEA (2000)
Solar PV modules	EU	1976}1996	21#	sale price ($/W$_{pd}$)	cum. sales (MW)	IEA (2000)
Ethanol	Brazil	1978}1995	22$	sp. sales price ($/boe)	cum. prod. (cubic meters)	IEA (2000)
Coal power plants	US	1960}1980	1.0}6.4%	sp. inv. cost ($/kW)	cum. cap. (units)	Joskow and Rose (1985)

! Note: sp. " speci"c; inv. " investment; cum. " cumulative; cap. " capacity; prod. " production.

" Based on Neij (1999). The learning rate of 4% considers only wind turbines equivalent to 55 kW or larger. The 8% learning rate reported in Table 1 for Neij's data includes all Danish wind turbines.

21% is the learning rate for the `stabilitya stage described in the text. For the `developmenta and `price umbrella a stages the learning rate is 16%. For the `shakeouta stage it is 47%.

$ 22% is the learning rate for the `stabilitya stage described in the text. For the `developmenta and `price umbrella a stages the learning rate is 10%. For the `shakeouta stage it is 53%.

% Joskow and Rose estimate a range of learning rates for di!erent utilities, architect-engineering "rms, and technology categories, after accounting for in#ation, plant size, the inclusion of scrubbers or cooling towers, whether certain structures are indoors or out, and whether a unit is the "rst on a site.

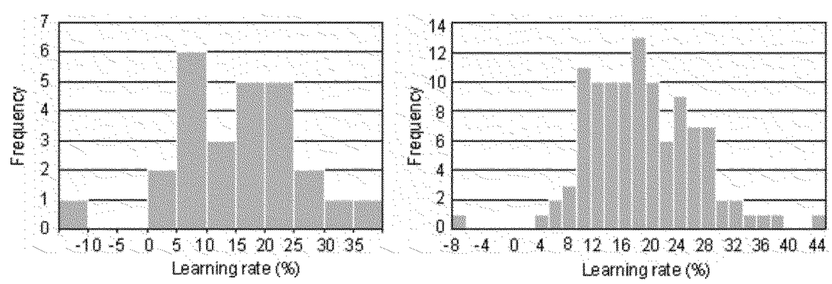

Fig. 2. Distribution of learning rates in Table 1 (left panel) and as observed in 22 "eld studies (right panel) (Dutton and Thomas, 1984).

uncertainty about this value than suggested simply by the $R2$ value of 0.99.

The frequent occurrence of low values for $R2$ in Table 1 means that further research is needed to discover missing explanatory factors, some (but not all) of which may be important to include in long-term energy models. As an example of such additional information, consider the one negative&learning" rate in Table 1, }11% for gas turbine combined-cycle (GTCC) power plants from Claeson's 1981}1991 data. Note "rst that the dependent variable for this dataset is the speci"c investment *price*, not cost. Prices are driven by many factors besides costs, and are for that reason inferior to costs as measures of learning and technological progress. In this case in particular, one

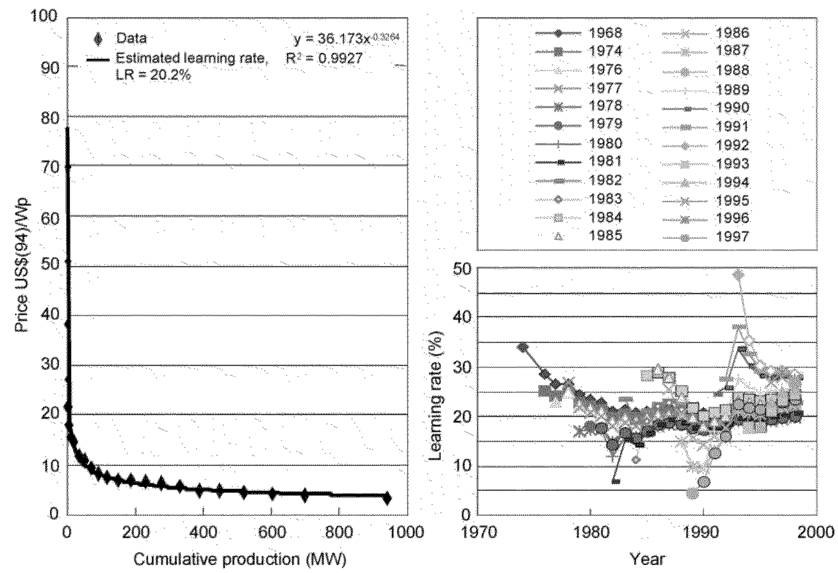

Fig. 3. Learning curve estimated for Harmon's data (2000) on unit prices for solar PV modules (left panel) and variability in learning rates (right panel).

possible explanation of the negative learning rate is short-term oligopolistic pricing behavior (Claeson, 1999). To the extent that such behavior explains the negative learning rate for this dataset, the calculated learning rate is largely irrelevant for long-term global energy scenarios in which *costs* rather than prices are the relevant variable. Another explanatory factor is suggested by the negative learning rate shown in the right panel of Fig. 2, which describes the production experience of Lockheed's L-1011 TriStar and provides good evidence of experience depreciation. Experience depreciation is much more relevant to long-term energy scenarios than short-term oligopolistic pricing behavior. It should thus be given higher priority in subsequent research to quantify the missing explanatory factors indicated by low $R2$ values in Table 1.

We now turn to the third important feature of Table 1, variations in learning rates among and within data sets for the same technology. Two cases are evident in the table, gas turbines and GTCC power plants. If we neglect the GTCC data set with the negative learning rate (for the reasons discussed in the last paragraph), the trend seems to be that later data imply lower learning rates. Some energy modeling groups therefore use `kinkeda (piece-wise linear) learning curves, with successively lower learning rates for technologies at more mature development stages (Kouvaritakis *et al*., 2000).2 In an alternative formulation, used by Argote (1999) and others, experience depreciates with time, i.e., experience gained from units built last year results in greater current cost reductions than experience from 10 years ago. This formulation results in the same phenomenon of decreasing learning rates, but in a smooth fashion, not requiring largely arbitrary boundaries between di!erent development stages. Both Argote's and the `kinkeda approaches can lead to learning `#oorsa, i.e., non-zero minimums below which unit costs will never fall.

To evaluate and enhance the usefulness of the estimates in Table 1 we need to summarize additional information, provided by the original sources, that might have potentially misleading impacts on learning rate estimates. First, as noted above, prices can be very imperfect measures of costs, and for a number of entries in Table 1, it is price that is the dependent variable. Goldemberg's ethanol data (1996), for example, are in terms of the price paid ethanol producers in Brazil, and a closer look at his original data suggests that these prices have to some extent moved up and down with international oil prices. Thus, some of the variability in Goldemberg's data re#ects not variability in ethanol production costs, but volatility in the international oil markets. In this light, estimated learning rate of 20%, as in Table 1, appears more reliable than indicated by the associated $R2$ value of 0.89. Neij, who also analyzes prices, "nds indications in her data of wind-turbine manufacturers selling below cost to drive out competitors (Neij, 1999). If this is indeed the case, her price data should underestimate costs nearer the beginning of her dataset and overestimate costs near the end (presuming less competition after some competitors have left the market). In that case, the learning rate of 8%, estimated from her data in Table 1, would appear to be too low.

2 We refer here to kinks in learning curves for *costs*. Such kinks re#ect postulated decreases in learning rates as technologies mature. This is di!erent from proposed kinks in learning curves for *prices* to re#ect changing relationships between cost and price learning rates as markets mature (see discussion of the IEA/BCG model).

The International Energy Agency (IEA) o!ers a general extended model of relationships between costs and prices based on prior work by the Boston Consulting Group (BCG) (IEA, 2000). The qualitative background of the model is the assumption that costs decrease at a constant learning rate, but price reductions can be divided into four stages. In the "rst two stages (`developmenta and `price umbrella a), the learning rate in terms of prices is constant but lower than the constant learning rate for costs. In the `shakeouta stage the learning rate for prices is higher than that for costs. And in the `stabilitya stage, learning rates for prices and costs are identical. This model is consistent both with Goldemberg's data cited above (see Table 2) and with Neij's data. Her estimated 8% learning rate is close to the 10% the IEA considers typical for the `developmenta (and `price umbrellaa) stage. It can also help explain Akisawa's study (2000) of prices for new `heat-pumpa air conditioners. He noted particular price volatility around the time the new technology was most aggressively displacing conventional air conditioners. Calculations based only on data from after the period of price volatility yield both a higher learning rate (17%) and higher correlation coe$cient (0.94) than the data set as a whole. Postulating that the post-volatility period corresponds to the stability stage of the IEA/BCG model, a learning rate of 17% would be more appropriate in long-term energy models than the 10% shown in Table 1 for the whole data set.

In addition to experience depreciation and short-term pricing behavior, other possible causes of variability or biases in Table 1 include:

- di!erences in performance measures (e.g., investment costs vs. production costs) or in experience measures (e.g., cumulative capacity or cumulative production),
- de"nitional di!erences (are the costs of land acquisition, pollution abatement, and interest during construction treated uniformly for all entries in a data set?),
- varying intensities of research and development (R&D),
- economies of scale,
- and cost variability for such things as land costs, wages, and interest payments that are driven by property, "nancial, and labor markets.

At this stage we can say something about di!erences in performance and experience measures and about economies of scale, but not much about the other factors. (An important focus of future research, however, will be the interplay between learning rates and R&D, given the pressure on governments to increase energy R&D expenditures.) Concerning di!erent performance and experience measures, we expect learning rates calculated using production costs and cumulative production to be higher than those using investment costs and cumulative capacity *if* there are concurrent increases in load factors. This is especially true if fuel costs are low * n.b., the variations in learning rates for wind in Tables 1 and 2.3 Concerning economies of scale, the learning rate in the last row of Table 2 for coal-"red power plants is calculated from a regression that includes a scale term. Thus, it re#ects learning after any economies of scale have been taken into account. This is not the case for the other power plant data presented here. They almost certainly include some scale e!ects, which may partially explain why they yield generally higher learning rates than the last row of Table 2. For long-term energy modeling, however, it is not clear how much e!ort should be put into trying to distinguish between the two factors. Given the data that are available, model inputs in which learning and scale economies are lumped into a single estimated learning rate may be simpler, as reliable, and therefore more useful than e!orts to extract the two separate e!ects from the empirical data, and then treat them separately in long-term energy models.

The purpose of the analysis presented here was to expand the empirical basis for the choice of learning rates and uncertainty ranges used in long-term energy models. We have presented a "rst edition of a catalogue of energy-related learning rates intended to quantify the phenomenon of experience-related cost reductions at a level useful to energy modelers. Analyzing the quality of the statistically estimated learning rates we conclude that some of the identi"ed causes of data variability, such as price swings due to marketing strategies, can be considered random and inconsequential for long-term energy models. More work is necessary, however, to properly address other factors, particularly experience depreciation and the impact of R&D investments.

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3 For wind power IEA 's data show higher learning rates when using production costs and experience than when using investment costs and cumulative capacity. This they attribute partly to increasing load factors. They also attribute the di!erence in learning rates, depicted in Table 2, for the EU and the US partly to faster load factor learning in the US. But this still leaves unexplained the di!erence between the US learning rate in Table 2 (32%) and the California learning rate in Table 1 (18%).

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Public procurement and innovation—Resurrecting the demand side

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Abstract

Demand is a major potential source of innovation, yet the critical role of demand as a key driver of innovation has still to be recognised in government policy. This article discusses public procurement as one of the key elements of a demand-oriented innovation policy. The paper starts by signaling the new significance of public procurement for innovation policy strategies at the EU level and in a range of European countries. It then defines the concept of public procurement and embeds this concept within a taxonomy of innovation policies. The rationales and justifications of public procurement policies to spur innovation are discussed, followed by a consideration of the challenges and potential pitfalls as well as appropriate institutional arrangements and strategies, including some recent empirical examples of good practice. It concludes by confronting the public procurement approach with two of the most common objections to it and by considering future prospects.

Keywords: Innovation policy; Public procurement; Demand and innovation; Concepts of demand-oriented policy; Public sector innovation

1. Introduction

Demand is a major potential source of innovation yet the critical role of demand as a key driver of innovation has still to be recognised in government policy. Public demand, when oriented towards innovative solutions and products, has the potential to improve delivery of public policy and services, often generating improved innovative dynamics and benefits from the associated spillovers. Nonetheless, public procurement as an innovation policy has been neglected or downplayed for many years. In the 1970s, a number of empirical studies explored the meaning of procurement for innovation (for an overview, see Mowery and Rosenberg, 1979; Rothwell and Zegveld, 1981; Rothwell, 1984). Rothwell and Zegveld (1981) compared R&D subsidies and state procurement contracts without direct R&D procurement. They concluded that, over longer time periods, state procurement triggered greater innovation impulses in more areas than did R&D subsidies (see also Rothwell, 1984, p. 330). Geroski (1990, p. 183) also analysed the quantitative and qualitative meaning of state demand for innovation and concluded that procurement policy "is a far more efficient instrument to use in stimulating innovation than any of a wide range of frequently used R&D subsidies".

In a more recent survey of more than 1000 firms and 125 federations, over 50% of respondents indicated that new requirements and demand are the main source of innovations, while new technological developments within companies are the major driver for innovations in only 12% of firms (BDL, 2003). An analysis of the Sfinno data base collecting all innovations commercialized in Finland during between 1984 and 1998 (Palmberg, 2004;

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Saarinen, 2005) shows that 48% of the projects leading to successful innovation were triggered by public procurement or regulation.[1]

Not only demand as such, but also the interaction between demand and supply has crucial implications for innovation dynamics. Starting with von Hippel (1976) and Mowery and Rosenberg (1979, p. 148), a range of studies have argued that a major task for systemic innovation policy is the organisation of a discourse between users, consumers and others affected by innovations in order to articulate and communicate preferences and demand to the market (see also Smits, 2002). Furthermore, the scale and characteristics of demand in a given location have been recognised as major determinants of the competitiveness of locations and their innovation dynamic (e.g. Porter, 1990).

In principle, the potential for using public procurement as an instrument for innovation is considerable. At 16.3% of the combined EU-15 GDP (Georghiou, 2004), public procurement represents a key source of demand for firms in sectors such as construction, health care and transport.[2] Nonetheless, with a few exceptions, for many years the potential offered and challenges posed in using public procurement for innovation have been largely ignored in innovation policy, both conceptually and in practice. It has been argued that the introduction of more stringent competition regulations across the European Union has proven a major factor in the declining use of this instrument (Edquist et al., 2000). The extent of relative decline is indicated by statistics showing EU procurement four times less than the US in civilian sectors and two times less when defence is taken into account (Directors Forum, 2006). However, in the last 3–4 years, the issue has received renewed attention, especially at the EU level but increasingly so at national level in a number of Member States.

This article analyses the concept of public procurement as an integrated tool of innovation policy.[3] It explores the factors which have led to this renaissance of what has been considered a mature, if not obsolete approach, and its importance within the portfolio of demand-side policies. The paper starts by signalling the new significance of public procurement for innovation policy strategies at the EU level and in a range of European countries. It then defines the concept of public procurement and embeds this concept within a taxonomy of innovation policies. The rationales and justifications of public procurement policies to spur innovation are discussed, followed by a consideration of the challenges and potential pitfalls as well as appropriate institutional arrangements and strategies, including some recent empirical examples of good practice. The paper concludes by confronting the public procurement approach with two of the most common objections to it and by considering future prospects.

2. A new wave of interest: public procurement in the innovation policy debate at EU level

At European Union level a new interest has emerged in the meaning of demand-side approaches to innovation and, more concretely, in the use of public demand as an engine for innovation. The emphasis has been on the link between procurement and perceived under-investment in R&D by business. The way in which procurement has entered the policy agenda is in itself an interesting case-study in how an issue gets taken up by the system. Following the work of an expert group (Georghiou et al., 2003), procurement for innovation was incorporated as an element of the European Commission's Research Investment Action Plan to raise R&D expenditure to the 3% Barcelona target (European Commission, 2003). Follow-up work includes a specific action to support the development and diffusion of information to public buyers (for example, on best available technologies) and an initiative to set procurement in the broader context of "policy mixes", thereby exploiting synergies with other research and innovation policy measures, for example, technology platforms.

The issue gained further momentum within Europe when early in 2004 three governments issued a position

[1] There is further consensus in the literature, that military demand in systematic conjunction with military R&D programmes was the key to the development and diffusion of many technologies especially in the US (Internet, many further ICT technologies, Global Positioning System (GPS) and other satellite technologies (Alic et al., 1992; James, 2004; Wessner, 2004) and – lately – diagnosis and therapy methods within the military project Bioshields (James, 2004, p. 35)). However, the economic efficiency of procurement resting on military needs and only indirectly spilling over to private markets has been strongly challenged (Wessner, 2004; Cohen and Noll, 1991; Kelley, 1997; DOD, 1999; James, 2004, p. 29). Therefore, and because of the peculiarities of the defence market, defence procurement will not be dealt with in this article (see James, 2004 for an overview).

[2] There are alternative figures for the size of public procurement in different EU countries, depending on different assumptions concerning inclusion of all government levels. Audet (2002), for examples, reports slightly lower shares of public procurement within GDP. He also shows that the shares differs between the EU countries, in his calculation ranging from almost 5% in Belgium to slightly more than 13% for Sweden.

[3] For a broader overview on demand oriented measures in general, including the support of private demand, see Edler (2007a, 2007b, in press).

paper to the European Council which included a call for using public procurement across Europe to spur more innovation (French/German/UK Governments, 2004, p. 7). In November 2004 the "Kok Report", which was reviewing progress on the Lisbon strategy, recognised that procurement could be used to provide pioneer markets for new research and innovation-intensive products (Kok et al., 2004). The March 2005 European Council endorsed the mid-term review of the Lisbon strategy and the proposal to make jobs and growth its central focus and explicitly called on Member States to renew their focus on public procurement of innovative products and services (European Council, 2005). A new impetus for demand-side innovation policies was provided by the Aho Group Report "Creating an Innovative Europe" presented to European leaders at their Spring summit in 2006 (Aho et al., 2006). The Panel, previously mandated by the leaders to report on ways to accelerate the revised Lisbon Strategy, argued that an R&D-driven strategy was insufficient and advocated instead a four pronged approach focused on the creation of innovation-friendly markets, strengthening R&D resources, increasing structural mobility, and fostering a culture which celebrates innovation.

Central to the Group's approach was the observation that the reason business is failing to invest enough in R&D and innovation in Europe is the lack of an innovation-friendly market in which to launch new products and services. To create such a market they recommended actions on harmonised regulation, ambitious use of standards, a competitive intellectual property rights regime and driving demand through public procurement. Large-scale strategic actions were called for to provide an environment in which supply-side measures to raise investment in research and innovation can be combined with this process of creating an innovation-seeking demand and a market. The Group identified several application areas: e-Health, Pharmaceuticals, Energy, Environment, Transport and Logistics, Security, and Digital Content. In order to secure implementation, the Group called for the appointment of an independent High Level Co-ordinator to orchestrate European action in each area across Member States, different parts of government and the Commission, business, academia and other stakeholders.

The recommendations of the Aho report were widely endorsed. Again, the EU Council in Spring 2006 explicitly backed the report and called for the support of markets for innovative goods and services, including public procurement (European Council, 2006, p. 6), a point reiterated in the European leaders' informal summit on innovation at Lahti, Finland, in October 2006. The Finnish Presidency had opened its programme with an informal Ministerial meeting at which the background paper was entitled "Demand as a Driver of Innovation—Towards a More Effective European Innovation Policy" (Finland's Presidency, 2006). This focussed on "horizontal" measures to stimulate demand for innovation such as regulation, standards and IPR but also raised the possibility of using public procurement for innovation related purposes.

Further action at EU level included a broad study on public procurement activities across Europe and in selected non-EU countries (Edler et al., 2006) that feeds into a Commission Handbook on Public Procurement for Innovation published in spring 2007 (European Commission, 2007). In September 2006, the Commission issued a strategic innovation policy paper highlighting the importance of public procurement for innovation and the creation of lead market, especially in sectors in which the state is an important purchaser (European Commission, 2006a). A specific initiative in the ICT sector has been the proposal to explore "pre-competitive procurement of R&D" as an instrument exempt from some of the competition restrictions affecting procurement of innovative goods and services.

The increased interest in public demand to spur innovation is also evident at national level. The UK has the most systematic and advanced approach. The UK Government's Innovation Report of 2003 proposed a series of measures aimed at increasing the research and innovation impact of public procurement (DTI, 2003a). Consequent actions on various levels and including various sectoral ministries include the production of a guide by the Office of Government Commerce on "capturing innovation" (OGC, 2004) to make innovation procurement an issue at the operating level. The procurement strategies of the National Health Service and the Ministry responsible for the environment (DEFRA) are leading examples of efforts to change practice. Studies and/or promotional activities for innovative procurement have been carried out by the Irish Science and Technology Policy Agency, Forfás, in Spain, by the COTEC Foundation, and in the Netherlands by an internal group of experts set up by the government. In Germany the "Impulse Group Innovation Factor State" has been working on the possibility of promoting innovation dynamics from the market place by adjusting procurement practice in general, as well as through strategic procurement measures in selected technology areas (e.g. BMWI/BME, 2006). The absence of an explicit policy of procuring innovations does not signify a lack of action, as many countries have started activities especially in the ICT sector, without a framing strategy (Edler et al., 2006, p. IX).

Why, one might ask, has the recent interest in public procurement to spur innovation been so great? We may infer from the critical tone of the above-mentioned policy documents that the principal driver is a sense that traditional supply-side innovation policies are insufficient to meet the challenges posed in promoting competitiveness. Before, outlining the conceptual justifications, we position public procurement within the toolbox of innovation policy.

3. Public procurement in the context of innovation policy instruments

Since the 1990s innovation policy has been perceived as a means to act on and improve the performance of innovation systems. As well as explicit innovation policies, many other measures also affect innovation, though this is not their main object. This group includes macro-economic policies, education more generally, regulation (e.g. pollution or health and safety), and competition policy. Crucially this group also includes public procurement.

There are long-running debates concerning the degree to which it is legitimate for governments [4] to intervene in the economy in support of innovation. Economic rationales for innovation policy rest on two main foundations, market and system failures, which in some senses compete and in others are complementary. We shall return to this discussion below in the context of public procurement.

The *innovation systems* perspective emphasises the significance of having a large and differentiated group of innovation actors and an enabling framework for learning-oriented interactions between them. Thus, policy is primarily aimed at optimising the interaction of various "components of the system", i.e. industry, basic research, applied research, financing *and demand* and at creating innovation-friendly framework conditions (Arnold et al., 2001). This understanding makes it clear that if innovation policy is to prove effective within the system, it must be capable of acting upon a large variety of actors and linkages and thus itself be differentiated. An important dimension of the systems perspective is that it fully integrates the *demand for innovations* on a conceptual level (for many Nelson, 1982; Lundvall, 1988, 1992). One would have expected that the effect of this perspective would be that demand should also have moved into the focus of innovation policy debate, yet if anything the range of policies directed towards demand has narrowed during the period in which the innovation system approach has become the received wisdom.

The lack of a demand-side orientation in innovation policy is reflected in two databases compiled on the basis of inputs from national correspondents under the sponsorship of the European Commission. The first is the Commission's "Trend Chart" (http://trendchart.cordis.lu/), which monitors innovation policy in EU member states and other regions and provides a comprehensive list and detailed information on national innovation policy measures. In total, this classification of innovation policy measures extends to 17 different types of measures. Not one of these types is *explicitly* oriented towards demand. Demand subsidies, state procurement of innovative goods and similar measures are not seen as *innovation policy* instruments in this categorisation. In addition, an inspection in 2005 of the various measures in those categories, which could in principle include the demand side, revealed that only in a very small number of approaches is the user directly promoted or supported.[5] A second, more narrowly defined, database of business support measures, classified information and consulting activities, training and education, finance, industrial premises and environment and strategic services (http://europa.eu.int/comm/enterprise/smie/overviewbytype.cfm) also shows little activity in support of technology diffusion. This cursory overview indicates that despite the inclusion of the user-perspective in innovation literature (Lundvall, 1988, 1992; for an overview, see Smits, 2002), conceptually very little consideration is paid to demand in innovation *policy*—while supply-side measures are highly differentiated.

In Plate 1, we present a first taxonomy that attempts to show both demand and supply-side innovation policy measures, and also to emphasise that broader policies not specifically targeted at research and innovation (here called framework conditions) can also influence these activities. For our purposes here, demand-side innovation policies are defined as *all public measures to induce innovations and/or speed up diffusion of innovations through increasing the demand for innovations, defining new functional requirement for products and services or better articulating demand.* Our taxonomy already indi-

[4] The term government here encompasses all levels including national, regional and supra-national and combinations thereof in multi-level governance.

[5] A search of the Trendchart's policy measures in 2007 indicates only one mentioning general procurement (access for French SMEs to defence procurement) and six using the term in the context of R&D procurement (http://trendchart.cordis.lu/tc_search_site.cfm).

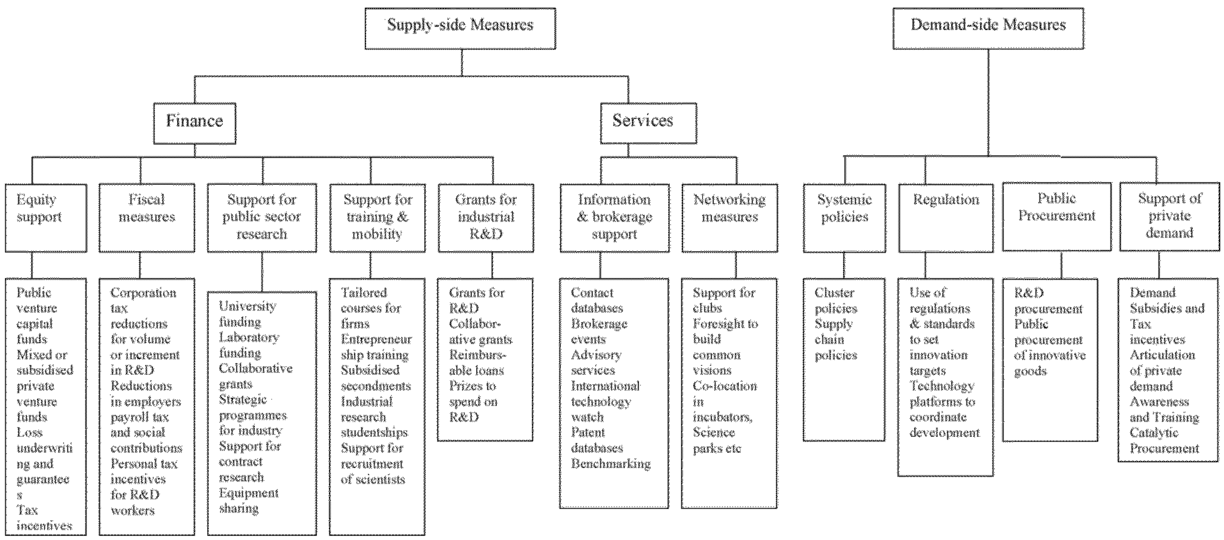

Plate 1. Taxonomy of innovation policy tools.

cates that if conceptualised in their innovation policy dimension—demand measures may be differentiated in the same way as supply-side measures (see Edler, 2007a, 2007b, in press), and that public procurement is only one of a range of measures.

It may be seen that demand-side policies can be presented in four main groupings, systemic policies, regulation, public procurement and stimulation of private demand. It is self-evident, that, as with any taxonomy, this is a simplified picture of reality. In particular, there are many policy measures that combine individual measures. As will be seen further below, public procurement can be a cornerstone of a co-ordinated and technology or sector specific mix of policies. Furthermore, in this paper, we focus on procurement, but it should be stressed that demand-side innovation policies also rest strongly on the use of regulation and standards and more broadly on the concept of promoting lead markets (Blind et al., 2004; Edler, 2007a; Georghiou, 2007). We include systemic policies in the demand-side category because of their critical role in bringing users and suppliers together.

4. Forms of public procurement

Public procurement of innovation as a strategy in innovation policy can take different forms. We can distinguish general procurement practice versus strategic procurement, direct public procurement (where the goods or services are exclusively for public use) versus catalytic procurement and, finally, commercial versus pre-commercial procurement.

4.1. General versus strategic procurement[6]

In state procurement two levels may be distinguished, which, in the literature at least, are usually not distinguished. At the first level, government procurement is *generally* organised such that innovation becomes an essential criterion in the call for tender and assessment of tender documents. Such an approach is being tried at present by the UK. As a rule, central procurement offices are generally responsible for procurement. They are located either in ministries of the interior or finance, but not in the ministries responsible for innovation policy.

The second level, *strategic* procurement, occurs when the demand for certain technologies, products or services is encouraged in order to stimulate the market. Strategic procurement is as a rule associated with sectoral policy and therefore to a large extent again is neither initiated nor co-ordinated by the ministries responsible for innovation.

A systematic utilisation of both forms of government procurement calls for co-ordinated action, i.e. co-ordination between various ministries and authorities and their admittedly widely different targets and incentive structures. We will return to these conditions below. We should also note the association of state procurement with the broader issue of innovation in public services,

[6] This and the following paragraphs are based on Edler (2007b, in press).

itself connected to public sector reform with, for example, increased outsourcing from private suppliers. The interface with the customer or user is identified as one of the key distinctive factors in public service innovation (Koch and Hauknes, 2005).

4.2. State procurement in connection with private users

There are procurement strategies where the state buys, not only to fulfil its own (original) mission, but also to support private purchasers in the decision to buy (Rothwell, 1984). So-called co-operative procurement occurs when government agencies buy jointly with private purchasers and both utilise the purchased innovations. Catalytic procurement occurs when the state is involved in the procurement or even initiates it, but the purchased innovations are ultimately used exclusively by the private end-user.[7] The crucial feature of catalytic procurement is that while the state often itself appears as buyer, the real market penetration effect is achieved by subsequent private demand. An example of this is the use of market transformation programmes in the energy sector in Sweden in the 1990s (Neji, 1999).

4.3. Commercial versus pre-commercial procurement

The desire to use procurement for innovation has led to new initiatives, especially at European level, that have further differentiated public procurement approaches. The basic idea behind public pre-commercial procurement is that it targets innovative products and services for which further R&D needs to be done. Thus, the technological risk is shared between procurers and potential suppliers. By definition, this means that potential producers are still in the pre-commercial phase, the products and services delivered are not "off the shelf". In practical terms the procurement in fact is an R&D service contract, given to a future supplier in a multi-stage process, from exploration and feasibility to R&D up to prototyping, field tests with first batches and then, finally, commercialisation.

The more innovative or idiosyncratic an innovation is, the more likely pre-commercial procurement can be appropriately applied. Within the pre-commercial stages and given that the benefits of the R&D contract are not solely for the contracting authority and the contract is not entirely paid for by the contracting authority, the WTO General Procurement Agreement (GPA) and the relevant European Directives do not apply (for details, see Bos and Corvers, 2007). This is the major difference from commercial procurement. The advantage in terms of innovation generation is that it gives procurers more freedom of selection, definition and interaction. The justification for this more flexible approach stems from the argument that R&D-intensive procurement needs more intensive interaction and cannot be judged on the basis of written specifications and proposals. To preclude monopolistic structures resulting from pre-commercial procurement, at least two competitors should enter the field-test stage. The pre-commercial procurement scheme being discussed at European level follows US approaches that have been implemented for many years by US multi-stage, multi-competitor R&D programmes, not only in the defence sectors (DARPA/DOD), but also in other areas such as energy, transport, health and in the cross-sectoral Small Business Innovation Research Programme (SBIR) (Directors Forum, 2006).

5. Rationales for applying public procurement as an innovation policy tool

The justifications and rationales for the use of public procurement to spur innovation relate to three levels: first, public procurement is a major part of "local" demand, which constitutes a major factor in the location decision of MNEs and in the inclination to generate innovations in a given location. Second, there is a range of market and system failures affecting the translation of needs into functioning markets for innovative products, and public procurement can prove effective in redressing this. Thirdly, the purchase of innovative solutions offers a strong potential for improving public infrastructure and public services in general.

5.1. The importance of local demand: lead markets and MNE location decisions

Domestic demand is a prime source for enhancing the competitiveness of locations and the enterprises therein. As Porter has shown in his pioneering work "Competitive Advantage of Nations" (1990), the *conditions of domestic demand* play a crucial role in the innovation dynamic of countries. Next to factor endowment, the industrial structure, and firm strategy (competitive situation), sophisticated and challenging demand is one of

[7] The classification of public procurement into public, catalytic and co-operative procurement has been coined by Edquist and Hommen (1998) and is based on the theoretically founded and empirically productive work on the innovation-inducing procurement system which was presented by a European team of analysts at the end of the 1990s (see Edquist et al., 2000, and also Rolfstam et al., 2005).

four key variables determining the attractiveness and performance of locations. Demand conditions also relate to the size of markets, with larger markets enabling local producers to reach economies of scale early on, and allowing more diverse feedback from users, etc. More importantly, demand conditions are determined by the sophistication of demand, which, in turn, drives producers to innovate, to meet new needs or regulations repeatedly, or in which an innovation-friendly culture is receptive to innovative products. Apparently, in each nation and even region, the quality of the demand for innovations and the inclination to adopt innovations is different, as evidenced by a survey from the World Economic Forum and other work (WEF, 2002; Tellis et al., 2003; early: Rothwell, 1984). As early as 1982, Nelson had argued that the bulk of new technology based companies in the US in the 1970s resulted from regional and national markets demanding innovations and accepting risk.

The inclination of populations and governments to absorb innovations at a certain location is shaped by many factors, the discussion of which is beyond the scope of this paper. However, there are locations where populations are more inclined to purchase and apply innovation than those from other regions. In Finland, for example, it has been shown that consumers and government traditionally tend to act as lead users and as prime movers when it comes to buying and applying new products and services. This has made the country for decades now a prime location for the introduction and diffusion of consumer electronics, and consequently has created a fruitful environment for the production of such products (Ebersberger, 2007). Thus, some countries are more internationally competitive in the areas in which they display challenging, future-oriented and international leading demand.[8] A strong factor endowment alone, i.e. the supply side, is not sufficient for sustainable, leading edge development and production.

This has also been demonstrated in the "lead user" concept of – among others – von Hippel.[9] Early users take the risk of working with a technology that may not be fully optimised in return for access ahead of their competitors or for achieving a desired solution to a problem more quickly. Innovators benefit from the learning and feedback that this environment offers. For small firms there is the added benefit of credibility gained by having an installation of their technology as the beginning of a reference list.

The concept of lead user can be extended to the concept of a lead market.[10] This requires early adoption of an innovation so that it becomes widespread through multiple users of this type or else through a single user with sufficient purchasing power to constitute a market on its own (this is where public procurement can make a difference). In such cases, the learning benefits are supplemented by a reduction of risk in the investment necessary to perform R&D and to innovate. The expectation is that other markets would then adopt the design thereby established giving it international dominance ("dominant design"). Characteristics of a lead market include customers willing to pay a premium for the particular characteristics of the innovation, or even in some consumer markets for its novelty per se. This could imply a high degree of customer "intelligence", meaning anticipatory knowledge of the technology. Compatible infrastructure may also be a factor. In general such markets should have sufficient scale for the costs of innovation to be viable. Market requirements should also be sufficiently generic to allow for expansion/export into wider markets as costs fall through continuing innovation or increasing scale of production. Finally, a lead market should provide the more general conditions favourable to innovation such as an efficient and responsive regulatory structure, security for intellectual property, etc.

There are, however, inherent risks in the lead market concept, notably the dominant design requirement. If a market requires product or service characteristics that are so specific (idiosyncratic) that the possibility of extension to other markets is foreclosed, the production and diffusion of an innovation in a local market does not result in a lead market. An example is the UK's System X telephone exchange developed by the then Post Office and launched in 1980 but failing to penetrate export markets. The French Minitel experience is a case where domestic success was not matched by exports in the face of emerging competition from the Internet.[11] A further risk in this approach is that in a narrow concept

[8] Although this general rule applies, Nachum and Wymbs (2002) have correctly emphasised that the characteristics of locations are of different importance not only in different sectors but also for different companies. For our issue of market endowments this means that while for some, the leading edge demand may be key for early development and innovation productions, for others the size of the market and thus production where economies of scale can be realised quickly is more important.

[9] von Hippel (1986) introduced the concept of lead users in innovation—defined as those whose present strong needs will become general in a marketplace months or years in the future.

[10] For a further discussion of lead markets, see Porter (1990), Meyer-Krahmer (2004, 1999), Meyer-Krahmer and Reger (1997), Beise (2001) and Beise et al. (2003).

[11] Wikipedia lists essentially failed efforts to introduce the Minitel in South Africa, Belgium, Canada, Ireland and the USA.

of lead markets, the suppliers of the innovation need to be located in the jurisdiction of the ministries responsible for the procurement policy. In fact, as empirical examples have shown, it is a major obstacle for agencies procuring innovations to pursue their goals when suppliers from abroad win the contract (Pinnau, 2005). However, the economic benefit is broader, as application of innovative products and solutions may lead to a technological upgrade of a location and a market. Such innovative products need to be installed and maintained, competing suppliers are put under pressure to catch up, complementary services and products need to be in place, users upgrade their skills and the location may gain a more innovative image. All of this benefits the local economy. In the case of the procurement of new, advanced lightning systems for the municipality and Federal State of Hamburg in Germany, for example, the responsible agency could convince decision makers and the public of the economic benefits of the purchase of these systems from abroad—in addition to the energy savings—and thus increased life cycle efficiency of the lighting system (Pinnau, 2005).

The role of the state in creating or assisting in creating lead markets mainly lies in the provision of a means to combine supply and demand-side measures. This includes provision of appropriate framework conditions that induce and enable innovative activity (infrastructure, sufficient R&D basis, support for co-operation, etc.). However, in addition, the state can support lead user and lead adoptions of innovations that promise to become a dominant design in the world markets. More importantly for our discussion on public procurement, the state can through the size or the peculiarities of public demand itself act as a lead user initiating lead markets.

5.2. *Market and system failures and the role of public procurement*

As with the justification for supply-oriented measures, there are market failures (mainly information asymmetries) and system failure (poor interaction) arguments.[12] Public procurement – adequately applied – may play a role in overcoming these failures.

The first set of failures is related to information problems. Especially, but not only, in fragmented markets there is a deficiency and an asymmetry in the information available to those intending to undertake or to purchase innovations. Purchasers, private and public, are often not aware, or fully aware, about what product and service innovation the market offers to them—or could offer to them. Suppliers of potential new products and services often lack the knowledge on what customers might want in the future. Suppliers, on the other hand, often fail to signal future solutions early enough. User–producer interaction and communication is often poor, with scattered demand not articulated sufficiently to make suppliers read the signals and translate them into innovations (e.g. von Hippel, 1976, 1986; Gregersen, 1992; Lundvall, 1988, p. 356; Moors et al., 2003; Rothwell and Gardiner, 1989; Smits, 2002). This is also related to a lack of trust for innovations and innovators on the side of private and public demand as well as lack of skills in order to use and exploit an innovation. All this entails risk – and even uncertainty – for suppliers.

Furthermore, the more radical an innovation, the higher the entry and switching costs. This relates to transaction and learning costs, to adoption of complementary equipment and to lock in and path dependency effects. Those problems of high entry costs are especially virulent in areas in which network effects occur. For products whose value rises with the units sold in the market, there is a high diffusion threshold, especially in ICT areas. The initial purchase of radical innovations is thus hampered. A strong initial demand in an early phase can have accelerating effects.

For a variety of reasons, public procurement may remedy those market and system failures and lead to the generation and/or better diffusion of innovations. Some of these reasons apply also to potential private purchasers, others are restricted to the state as purchaser (see also Geroski, 1990; Dalpé et al., 1992; Dalpé, 1994; Edquist, 1998).

Public procurement can achieve critical mass, through the sheer size of a single purchase or through bundling the demand of various public entities. Such public demand creates clear incentives for manufacturers, reduces their market risk, and enables early economies of scale and learning. This critical mass also structures the manufacturing branches connected with the innovation in question. This effect is especially strong for young technologies, i.e. when industry is able to react to strong impulses on the part of the state. In contrast to R&D subsidies, the concrete state demand for innovations leads not only to technological capacities, but at the same time to increased production capacities for innovations (Geroski, 1990, p. 189).

Public procurement may also lower the transaction costs of adapting to new products, either by the timely and large-scale use of an innovation or by demonstrating

[12] Chapters 5.2 and 5.3 partly draw on Edler et al. (2007) and Edler (2007a, 2007b, in press).

its use. The public uptake of an innovation further sends a signal to the private market; it demonstrates functionalities and thus raises early awareness (Rothwell, 1984; Porter, 1990). With this spillover to private demand, the catalytic function of public procurement may be more important than the initial public purchase, as the examples of market creation in the consumer electronics sectors especially in Sweden have shown (see below).

Finally, the state – supported by its purchasing power – may help to create meaningful standards, with convergence on a standard allowing firms to internalise spillovers and hence to increase the incentive to invest in R&D. Those standards further contribute to trust building for innovative products.

5.3. *Public procurement to improve public policy and services*

A further justification for public procurement that asks for leading edge products and services lies in the improvement of state functions and in contributing to achieving public missions (see the link to public service innovation noted above). The procurement of innovation may be linked to a normative policy goal, such as sustainability or energy efficiency, and this goal may be reached sooner and more effectively through innovation. The political goals are based on (perceived) social needs. As Mowery and Rosenberg (1979, p. 140) stated, a need does not equal demand that is articulated in and mediated through the market. This argument strengthens the case for public procurement as a market stimulating instrument, as it can be one means to translate perceived needs into concrete market demands. This is how the economic argument of triggering the innovation dynamic meets the sectoral, political argument of better performance in governance.[13] The justification for buying a costly innovation – to pay the innovation premium – and to invest in innovations at an early phase within the innovation cycle, then stems from this policy mission. The innovation lever of public procurement measures – and measures to improve private demand – which are designed to meet societal targets derives from the fact that most often societal goals underlying a procurement translate *new* needs into demand for which innovative solutions are called for (Gregersen, 1992, p. 144). Dalpé et al. (1992, p. 258 ff), have empirically shown that in satisfying new societal needs and providing infrastructure and public service, the state very often is more demanding than private consumers. In achieving its mission, in improving its function, the state very often acts as a lead user.

This close connection, namely to understand demand-oriented policy as innovation policy to achieve certain policy goals such as sustainability, energy efficiency, mobility, etc., is still insufficiently examined in the literature and poorly designed and taken advantage of in policy practice. Traditionally, sectoral policies that utilise public demand and mobilisation of private demand, have stressed their own specific mission without linking the dynamics that were triggered to innovation policy and related goals. In Europe, the green procurement movement (e.g. BMU, 2006; DTI, 2006) or activities in the ICT sector at EU level (Bos and Corvers, 2007) only recently have shifted in this direction (see below), expecting thereby to increase the momentum and public backing for the sectoral policy aims. This points towards the question about framework conditions and strategies conducive for public procurement policies geared towards innovation.

6. Implementation framework for innovation procurement policy—and some practical examples

Thus far we have seen that despite the strong interest in procurement for innovation, it does require certain circumstances conducive for its success. One requirement we have noted in Section 4 is the need for co-ordination across government, to resolve the problem of social returns not necessarily being within the ambit of the purchasing ministry. We have also noted in the same section that combination with private demand provides an additional dimension to procurement policy. We further stressed the critical role of linkages between supply and demand prior to and during the innovation process. In addition to these structural requirements there is also a need for changed practice at the level of the procurement professional. To overcome the challenge and to reap the benefits of public procurement in terms of innovation generation and diffusion, a complex implementation framework needs to be in place. We cannot be comprehensive in this article, but here focus on the four dimensions that appear to be of highest significance and address the issues raised here.

6.1. *Changing rationales and comprehensive inter-department strategies*

The basis for such an innovation-friendly procurement framework is the *general understanding across administrations* that the public purse can make a dif-

[13] McCrudden (2004) presents a number of cases in which the state has procured with a view to causing societal goals to be reached.

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ference in the marketplace towards a more innovative culture. This of course cuts across different administrative cultures and rationales. Ministries responsible for innovation must acknowledge that the lever of public procurement, the purchasing budgets, sits elsewhere and that in order to mobilise these budgets co-ordination and convincing is needed. Decision makers in sectoral ministries or divisions are confronted with an additional major target – innovation-generation – that alters the political equation when it comes to formulating their goals, pushing through their policy and implementing decisions. These additional dimensions might be helpful, but at first sight might also result in target conflicts. As discussed above, these target conflicts may arise if the optimum purchase for the sectoral goal is not in line with the optimum in terms of innovation dynamics in a given innovation system. Most importantly, the immediate economic benefit may be realised by suppliers who happen to be located outside the jurisdiction of the purchasing ministry or agency. Furthermore, the learning and switching costs for administrations may be perceived as being prohibitively high. The basis to overcome all of these principle obstacles is a *strategic commitment* to change rationales across and within administrations, to integrate the innovation rationale within sectoral policy rationales and subsequently a *strong co-ordination* of efforts to create inter-administrative win–win situations.

The new initiatives discussed above of pushing pre-commercial procurement forward also in Europe, albeit to pursue the potential benefit of contracting more public R&D services leading to market innovations, add further to the policy challenges. As procurement covers the whole stage from R&D to application, there is even more need for co-ordination between responsible ministries. In countries like the US or Japan, which have applied pre-commercial procurement much more systematically and comprehensively, this co-ordination need is met through bundling of competences. In the US, mission-oriented approaches facilitate co-ordination as sectoral ministries are responsible for R&D in their areas, in Japan, METI has a broader portfolio and wider responsibilities than traditional ministries of economics in Europe. In other OECD countries, the challenge of co-ordination is immense.

The most sophisticated and consequent approach of horizontal, goal-oriented governance in this sense in recent years has been the innovation strategy of the UK (Winson, 2005). Here, the Department of Trade and Industry incorporated public procurement as an official policy dimension into their innovation strategy (DTI, 2003a), building upon a background report on the economic benefits and the innovation potential of the £125 billion per year spent by the public administrations on goods and services (DTI, 2003b). In addition, discussions with industry had revealed shortcomings in the procurement process hampering innovative bids to be successful or innovative solutions to be detected in the first place. Subsequently a detailed strategic plan including a concrete roadmap was drafted that committed sectoral ministries under the leadership of the DTI, including the local level and special provisions for SMEs (DTI/OGC, 2003). The strategy aimed both at general procurement, i.e. sensitising and enabling procurers at all levels as regards to innovation procurement (see below), and strategic procurement, i.e. selecting strategic areas of sectoral policy and combining the innovation goals and the sectoral policy goals. The commitment of sectoral ministries has been mobilised through political backing at the highest ministerial levels, an implementation roadmap with clear targets and regular co-ordination meetings of working groups including ministers or undersecretaries of state. How far a country needs to travel is illustrated by a general perception that these measures have yet to bear fruit—there are constant calls from industry and most recently from the Conservative Opposition party to make procurement a much more prominent innovation policy tool (STEM Task Force, 2006).

6.2. Linking up with private demand

As mentioned above, a further strategic and organisational challenge for integrated procurement strategies lies in the combination of public procurement and private demand measures. Such catalytic approaches had been tested in the US already in the 1970 in form of the Experimental Technology Incentives Program. These had mixed results, but there were some interesting lessons to be learned (Rothwell, 1984). Most importantly, while in pure public procurement the needs are defined directly by the public bodies themselves, in catalytic procurement the needs of private buyers need to be systematically ascertained. Public purchasers must be well aware of the needs and of the readiness of consumers to purchase an innovation, and design their measure accordingly. The more a public policy is designed to change behaviour of consumers, the more catalytic procurement will have to be accompanied by further demand measures. The example of market transformation in Sweden is a point in case here.[14] The Swedish energy

[14] For a broader discussion of the Swedish catalytical procurement case, see Neji (1999), NUTEK (1994), Suvilehto (1997), Suvilehto and Överholm (1998) and Edler and Hafner (2007).

agencies NUTEK and STEM implemented a complex policy scheme aiming at an accelerated diffusion of energy efficient technologies. The major characteristic of this initiative was a technology specific mix of instruments, with public procurement as an ice-breaker and catalyst and with a mobilisation of private demand through a whole set of awareness measures, organised discourse with users and – in selected cases – complemented by direct subsidies to procurers. The instrument mix and the targeting of specific markets was not equally successful for all technologies, but evaluations showed that for many technologies market diffusion has significantly accelerated (Neji, 1999).

6.3. Coping with complexity and procurement discourse: bringing public needs and supplier capacities into line

A further requirement for innovation procurement is to define which markets and technologies to tackle. On the one hand, suppliers need to be given early signals regarding concrete future public demands. On the other hand, there is an uncertainty on what suppliers are actually ready to provide in the future. The major requirement for a strategic procurement policy thus is to bring future needs and future supply together at an early stage. The basic idea can be summarised by quoting an industry member of the UK Sustainable Procurement Task Force and Chairman of the Environmental Advisory Group initiated by the DTI and DEFRA (see below): "Tools, guidance, good practice, awareness raising and the like are all fine, but the real issue for the public sector is that its supply chains don't deliver, and there is no clear sense of what future performance will be required", says Frost. "New technologies come on stream fast when there's enough confidence and clarity within a supply chain about the direction of developments – which makes it worthwhile for a supplier to make the investments in R&D to achieve new performance standards".[15]

Furthermore, to some extent the complaint of Gibbons and Gummett still holds true, according to which it is extremely complex to detect needs and to translate them into meaningful market demands (Gibbons and Gummett, 1984). However, as public procurement focuses on *public* demand, governments can put in place selective, limited discourses that define mid- and long-term public needs derived from policy goals and administrative strategies. If potential suppliers are included, the likelihood is high to define demands concretely enough that can be met by industry in the future. The broader the participation in these processes, the more likely that future demand can be aggregated, signals are spread widely and competition for future solutions remains open. In addition, public decision makers need to learn the readiness of industry to deliver innovations. Public procurement can be extremely detrimental to a novel technology if the procurement sets in too early in the innovation cycle, i.e. when it is not ripe yet for broader market diffusion. One approach to inform about future direction of technologies as well as of future needs is the use of foresight strategies to develop common visions between producers and users (e.g. Georghiou, 1996).

Current examples of such discourses are the Technology Platforms at the EU level (European Commission, 2006b).[16] One example with well-established structures and intensive dialogue linking national and European level is the European Construction Technology Platform (ECTP, http://www.ectp.org). In the ECTP a number of stakeholders join, including industrial suppliers (contractors, materials and equipment manufacturers, service and technology providers, designers, architects, engineers), scientists (research centres and universities), financial institutions and, last but not least the demand side (owners, operators, clients, users/consumers, cities and regions). In the area of "Cities and Buildings", for example, the central document of the Platform not only defines a common vision as to how cities will look like and function up to 2030, but also explicitly the importance of procurement to mobilise the innovative potential of the sector (ECTP, 2006).

Another more advanced and concrete example is that of the stakeholder discourses established in the context of sustainable and innovative procurement in the UK. Here, for a couple of years the discourse on sustainable procurement has been linked to procurement of innovation. To that end, an Environmental Innovation Advisory Group (EIAG) has been founded by DTI and Department of Environment, Forestry and Rural Affairs (DEFRA) comprised of a number of industrial leaders and assisted by an institutionalised secretariat. One major step of this group has been to introduce a so-called forward commitment process. This approach mirrors the supply chain management of private companies in that it develops

[15] Jack Frost, Johnson Matthey Fuel Cells, see http://www.greenfutures.org.uk/supplements/takefuture_page2532.aspx (accessed November 30, 2006).

[16] Links to all Technology Platforms can be found in http://www.eupvplatform.org/index.php?id=75, for a comprehensive overview see also: http://ftp://ftp.cordis.lu/pub/technology-platforms/docs/tps_status_report_final_090305.pdf.

long-term demand for products and services and signals, early on, these needs to industry and attempts to bring in line demand and supply. First pilots have been conducted in diverse areas such as HM Prison Service or London Fire and Emergency Planning Authority (DTI, 2006).

6.4. Activating and enabling the procurement chain

To include high level decision makers is important not only to gain compliance of administrations, but also to signal the backing up of the risk involved in concrete procurement action to the entire procurement chain and subsequently to change incentive structures and practices along this chain. [17] Procurement of innovations runs counter to the traditional behaviour of public officials, decision makers and procurers alike. Incentive structures in public administrations tend to award contracts to those with low initial costs – following a simplistic understanding of efficiency – and high reliability of the public service. Innovations, however, are often more costly in terms of their initial price, and they contain the risk of not delivering the service at all, or with delay, and with switching costs for citizens. The more radical an innovation is, the more this is the case. Thus, stamina and sophisticated risk management are needed in order to cope with innovations in public services. A new cost–benefit rationale that translates into life-cycle costing and the criteria of the so-called Most Economically Advantageous Tender (MEAT) is needed to replaces the lowest initial cost rationale.

Furthermore, as discussed above, decision makers and procurers need a much more encompassing knowledge of future needs and of potential improvement as regards public services as well as of the market that offers or may offer new solutions. A structure in which procurers are very close to or even involved in the daily business of their administrations increases their ability to understand needs of administrations and the related technologies.[18] Specialised procurers, on the other hand, need close co-ordination with those responsible for the future development of public service and would have to mobilise expertise on technologies and markets, if needed through professional service providers.

In addition, for the tender process to induce innovation in the marketplace, it is indispensable that it is based on specifying functionalities rather than designs. In the environmental sector in the UK, for example, 66% of companies in a recent survey stated that public procurement was a major hindrance as the tender specification locked suppliers into traditional technologies not allowing for scaling up to radical innovation (DTI, 2006, p. 17). The hindrance mentioned as being second in importance was finance (60% of companies).

All this also requires organisational change and systematic training of procurers at the operative level. There are several attempts already in Europe to facilitate this change through mobilising existing procurement organisations for the dissemination of new practices. For example, in a recent initiative in the Netherlands (PIANO) procuring agencies are networked and share experience, good practice and new approaches (Bodewes and Boekholt, 2006), through electronic exchange, an electronic platform, annual events, and regional procurement sessions devoted to specific topics.

As regards procurement regulation, at the EU level the new directives 2004/18/EC and 2004/17/EC have created opportunities for public authorities to purchase innovative solutions, with key changes including:

- The facility to specify requirements in terms of functional performance or standards that allows suppliers to produce any configuration of technology they feel can meet the need.
- Options to permit variants, thus opening up bids to alternative ideas.
- Conditions that allow transfer of intellectual property to the suppliers, and hence allow them to exploit their innovations in wider markets.
- Possibilities for technical and competitive dialogues between purchaser and supplier, a necessary condition if each side is to understand the other.

7. Conclusions

In this article, we have outlined the rationales, potential and necessary framework conditions for the use of public procurement as one type of innovation policy measure. The recent ongoing public debate especially in Europe but also in catching up countries such as China has revitalised this concept. There are obvious opportunities opened up through public procurement for

[17] Wilkinson et al. (2005) give a very detailed prescription on how to tailor the various phases of the procurement cycle towards more innovation. Here only major issues are highlighted. The Office of Government Commerce has issued guidelines for procurers in order to act as an “intelligent customer” striving for innovations in the procurement process (DTI/OGC, 2003), and this model is followed by other countries as well (e.g. Germany, BMWI/BME, 2006).

[18] In Edler et al. (2006), there is an example of the procurement of a Voice over IP system within the municipality Heidelberg, Germany, in which the procurer was at the same time responsible for the internal maintenance and development of the system. This enabled a two-way translation of needs and skills on the one hand and market offers on the other hand.

mobilising innovation and at the same time better achieving public policy goals and delivering better service to the citizens.

There is a clear potential danger that globally, but especially within Europe the national champion policy might make a comeback through public procurement favouring local companies. In principle, the WTO rules (Government Procurement Agreement, GPA) and the EU directives do not allow this. However, in countries that are not bound by the WTO GPA this is an obvious issue and opportunity. China, for example, has recently put in place a policy that explicitly discriminates against foreign owned companies when it comes to procurement of innovations. In fact, such procurement is a cornerstone of a new catching up strategy that increasingly relies on the increase of innovative capabilities of indigenous firms (Edler et al., 2007). From the perspective of internal market and free trade, this is a problem—especially within the EU. Not to violate the rules of free trade and open competition on the one hand and still to justify procurement in terms of innovation is – next to the institutional adaptation discussed above – the major challenge for procurement policies integrated in innovation policy strategies.

To reiterate our argumentation above, there are two possible answers to this challenge. One is the definition of benefit for the country, region or municipality that procures. This benefit not only lies in the direct production of a supplier, but in the accompanying services, the installation and maintenance needed and so on. Learning and technological improvements tend to spill over within the market in which the procurement takes place. Second, following the logic of technologically driven competition in conjunction with "demanding demand", advanced public procurement may enhance the technological level of competition, and also set incentives for local producers to face the technological challenge posed by advanced demand. Competition among producers and accompanying services and suppliers of the innovation is upgraded. In the long run, this benefits all related economic agents in a location.

To deal with one last apparent objection, is public procurement about choosing one solution over the other through state intervention rather than letting markets decide; is it another variation of a "picking-winner strategy"? Not really. Picking winners was about selecting firms (national champions, sometimes ailing national champions) or about selecting technologies (specific solutions). Strategic public procurement is about selecting whole market areas in terms of their importance in the economy and their apparent ripeness for innovation. No specification is to be made of which firms or even of which solutions should be pursued in the first instance (Georghiou, 2006). Eventually under competitive conditions preferred solutions and suppliers will emerge but this happens in all markets. What must be achieved is an open process the result of which is that winners emerge. It is possible to deal with other concerns by the ways in which lead markets are promoted as a policy. First, a demonstrated level of commitment from business should be a prerequisite for action—a sector where the desire for co-ordination has already emerged. Secondly, the measures taken within that sector should preserve competition wherever this is feasible. For example, in procurement second sourcing, perhaps from an innovative SME could keep alternative options open.

The aim of this article was not to reignite the old discussion on the relative importance of demand vis-à-vis supply-side factors for innovation. Rather, we simply argue the need to take demand, more concretely public demand, more into the focus of innovation policy making and use it to complement existing and new supply-side measures. For reasons of space and focus we have concentrated on one aspect of demand-side innovation policy but the agenda is also potent in the use of regulation and standards as well as the various forms of public support to spur private demand for innovation (Edler, in press). It is not an exaggeration to say that finding ways to mobilise these potentially powerful incentives for innovation is the principal challenge currently facing those engaged in policy design.

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ATTACHMENT 17

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Opportunities and barriers to pumped-hydro energy storage in the United States

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ABSTRACT

As concerns about global warming grow, societies are increasingly turning to the use of intermittent renewable energy resources, where energy storage becomes more and more important. Pumped-hydro energy storage (PHES) is the most established technology for utility-scale electricity storage. Although PHES has continued to be deployed globally, its development in the United States has largely been dormant since the 1990s. In recent years, however, there has been a revival of commercial interests in developing PHES facilities. In this paper we examine the historical development of PHES facilities in the United States, analyze case studies on the controversies of disputed projects, examine the challenges to and conflicting views of future development in the United States, and discuss new development activities and approaches. The main limiting factors for PHES appear to be environmental concerns and financial uncertainties rather than the availability of technically feasible sites. PHES developers are proposing innovative ways of addressing the environmental impacts, including the potential use of waste water in PHES applications. In some cases, a properly designed PHES system can even be used to improve water quality through aeration and other processes. Such new opportunities and the increasing need for greater energy storage may lead policymakers to reassess the potential of PHES in the United States, particularly for coupling with intermittent renewable energy sources such as wind and solar power.

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1. Introduction: significance of bulk electricity storage in a carbon-constrained world

Most low-carbon electricity resources cannot flexibly adjust their output to match fluctuating power demands. For instance, nuclear power plants best operate continuously and their output cannot be ramped up and down quickly. Wind power and solar energy are intermittent and their operators sometimes have no control over the schedule of electricity output. Utility-scale electricity storage to maintain balance and prevent blackouts remains a significant barrier to a de-carbonized power system.

There are only two large-scale (>100 MW) technologies available commercially for grid-tied electricity storage, pumped-hydro energy storage (PHES) and compressed air energy storage (CAES). Of the two, PHES is far more widely adopted. In the United States, there are 40 PHES stations with a total capacity of ffi20 GW.

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Worldwide, there are hundreds of PHES stations operating with total capacity of 127 GW [1]. Only two CAES facilities, one 110 MW facility in the United States and another 290 MW facility in Germany, are currently operating globally. Unlike CAES, PHES does not require burning fossil fuels and is also generally cheaper than CAES for energy storage [2].

A PHES facility is typically equipped with reversible pumps/generators connecting an upper and a lower reservoir. The pumps utilize relatively cheap electricity from the grid during off-peak hours to move water from the lower reservoir to the upper one to store energy. During periods of high electricity demand (peak-hours), water is released from the upper reservoir to generate power at higher price.

In recent years, there has been increasing commercial interest in PHES [3]. Developers are actively pursuing new PHES projects around the world. An additional 76 GW PHES capacity worldwide is expected by 2014 [1]. In the United States, the Federal Energy Regulatory Commission (FERC) has granted 32 preliminary permits (as of April 5, 2010) to 25 licensees who are interested in developing new PHES facilities [4]. The total capacity of these proposed PHES facilities is 28.6 GW, more than the existing PHES capacity in the United States. Nevertheless, based on historical and economic considerations, a number of these proposed projects are unlikely to be built. A brief review of the history of PHES development in the United States reveals the many challenges and barriers that exist today.

2. Historical PHES development in the United States

Connecticut Light & Power's Rocky River Station, completed in 1929, is the oldest pumped-hydro storage facility in the United States. The development of PHES remained relatively slow until the 1960s [5,6], when utilities began to consider the possibility of a dominant role for nuclear power [7]. Fig. 1 shows the cumulative installed PHES capacity in the United States.

Because the output of nuclear power cannot be ramped up and down quickly to meet fluctuating demands, pumped storage was perceived as an important complement to nuclear power for providing peaking power [8]. When nuclear development in the United States came to a standstill in the 1980s, PHES development also slowed dramatically. From 1986 to 2005, FERC issued 45 preliminary permits to study the feasibility of pumped storage projects. Only seven of the projects filed for licenses. Six of the seven projects were eventually abandoned (see Table 1) [9], and only one project from that period is still being studied through another preliminary permit.

Market uncertainties were a primary cause of termination of these projects. Beginning in the 1990s, electricity regulators in the United States started restructuring the power sector, transitioning to competitive wholesale markets that often separated power generation and transmission [10]. Electricity storage, unfortunately, sits in the gray area between generation and transmission [11]. A PHES facility does not qualify as a power-generating facility

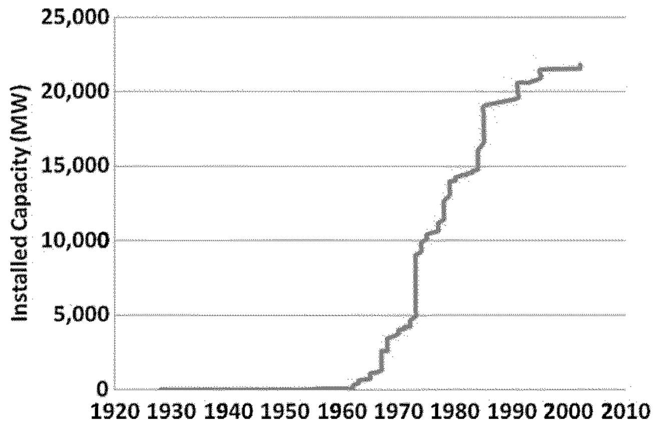

Fig. 1. Installed PHES capacity in the United States by date.

because its net power output is negative (i.e., a typical project recaptures only 70 or 80% of the power inputs). In the restructured wholesale power market, reserve capacity and ancillary services are typically fulfilled by peaking power generators. In the earlier stages of restructuring, it was unclear how or whether non-generating resources such as PHES could participate in these restructured markets. This regulatory uncertainty remained a serious deterrent to investment in energy storage until 2007. In that year, FERC issued Order 890 "Preventing Undue Discrimination and Preference in Transmission Service." The order required that non-generation resources (including energy storage and demand response) be evaluated on a comparable basis to services provided by generation resources in meeting mandatory reliability standards, providing ancillary services, and planning the expansion of the transmission grid. Since the issuance of this order, organizations responsible for transmission have been amending rules to allow energy storage to have greater market access.

Although PHES provides crucial load-balancing and ancillary services to the grid and reduces the needs for transmission upgrades, PHES facilities do not typically qualify as transmission infrastructure. For instance, the Lake Elsinore Advanced Pumped Storage project applied to be operated and/or managed by the California Independent System Operator (ISO), allowing it to be categorized as a transmission facility for purposes of rate recovery. However, FERC denied this request [12].

The benefits of bulk electricity storage are potentially useful to many sectors of society, including power generators, system operators, distribution companies, and end users. When regulators partially unbundled the power sector in the 1990s, they broke up PHES's potential revenues into pieces in different market sectors. Utilities generally recognize the value of PHES in the overall power system. However, operators were unsure if and how the PHES owners would be paid for their services after the restructuring.

Relatively low natural gas prices in the late 1980s and 1990s increased the use of natural gas in the U.S. power sector (see Fig. 2)

Table 1
Abandoned projects from 1986 to 2006.

Project name	Utility	Location	Duration	Stated cause of termination
Dry Fork	Little Horn Energy Wyoming, Inc.	Wyoming	1989–2000	Market uncertainty
Crystal Creek	Creamer & Noble Energy	California	1993–2000	Failure to obtain approval from California water quality board
River Mountain	JDJ Energy Co.	Arkansas	1994–2003	Market uncertainty, financial instability, inability to secure purchase agreement
Summit	Summit Energy Storage, Inc.	Ohio	1991–2001	Market uncertainty
Blue Diamond	Blue Diamond South Pumped Storage Power Company, Inc.	Nevada	1997–2005	Nevada electricity restructuring was taking longer than expected
Mt. Hope	Mt. Hope Waterpower Project, LLP	New Jersey	1992–2005	Market uncertainty

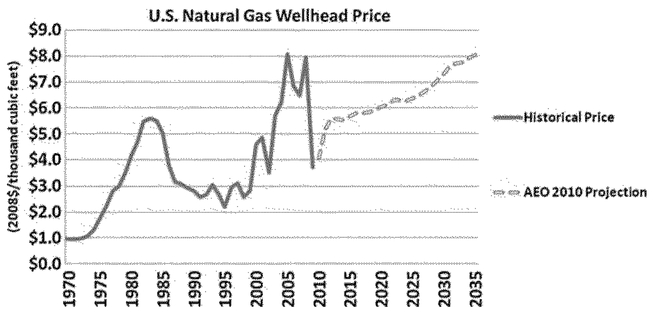

Fig. 2. U.S. natural gas wellhead price.

[13]. In the 1990s, almost all of the new electrical generation capacity was gas-fired [14]. Because PHES is essentially a peak-load technology, which competes directly with gas-fired power, low natural gas prices also help to explain the hiatus in PHES development in the late 1980s and 1990s along with the slow-down in new nuclear-power capacity.

Siting difficulties and environmental impacts were additional constraints on the development of PHES during this time. For example, the Department of Energy and the Electric Power Research Institute's handbook on energy storage concluded that "the addition of pumped hydro facilities is very limited, due to the scarcity of further cost-effective and environmentally acceptable sites in the U.S." [15]. Since the 1960s, there were many cases where proposed PHES projects were opposed by environmental groups. Some projects were eventually abandoned, while others were completed. The following five case studies from 1963 to 2006 illustrate some prominent cases relevant for understanding the potential development of PHES in the future.

2.1. Storm King

In 1963, Consolidated Edison (Con Ed) proposed to build a PHES facility at Storm King Mountain to help address the rapid growth of power demand in New York City. Had it been built, the project would have been the world's largest PHES facility at that time. Some local stakeholders objected to the potential damage the plant would cause to the environment of the Hudson Highlands and founded several environmental groups to block construction of the facility on the grounds that it posed a threat to the local water supply, Hudson River fisheries, and the scenic beauty and historic significance of Storm King Mountain [16]. Some researchers have even argued that Storm King helped start a new era of environmental advocacy in the United States that combined legal action with media outreach, public relations, and government lobbying [17].

In March 1964, FERC rejected the opponents' petitions and granted Con Ed a license. Opponents continued to challenge the FERC decision in court over the course of a 17-year legal battle [18]. Con Ed eventually terminated the Storming King project in 1981 and surrendered its Storm King license to FERC.

2.2. Richard B. Russell

The Richard B. Russell dam and conventional hydropower station in South Carolina offers a contrasting example where extensive cooperation with stakeholders and analysis of environmental impacts led to eventual project approval, despite early objections from environmental interests. The Russell hydropower station was completed and began operation in 1986. The Army Corps of Engineers, which owns the Richard B. Russell project, proceeded to add pump-hydro units to this facility. In 1988 the South Carolina Department of Wildlife and Marine Resources, joined by the South Carolina, Georgia, and National Wildlife Federations, filed an injunction to stop installation of the pump units. In 1992, the Army Corps developed a testing and monitoring plan in conjunction with opponents to evaluate the environmental impacts of PHES operation [19]. The assessment was divided into three phases. In phase I, lasting from July 1992 to August 1993, only short-duration pumping was allowed for purposes of collecting data for mechanical and electrical certifications of the four pump-back units. Phase II (August 1993 and August 1994) allowed only two unit pumping operations for collecting data for environmental impact assessments. Phase III (April 1996 and October 1996) simulated commercial operation for further assessment of environmental impacts. During this assessment, fish deterrent systems were installed and the pumping schedule was adjusted to minimize fish entrapment. An oxygen injection system was also installed to offset the potential oxygen loss due to warming of the water because of pumping. With these extensive modifications and preventive measures, the three-phase environmental assessment concluded that there were no significant impacts from the pump unit operation [20]. In 2002 the Federal District Court in Charleston, South Carolina lifted the injunction and the four pump units began commercial operation.

2.3. Bear Lake/Hook Canyon

In 2006, a private developer, Symbiotics LLC, applied for a preliminary permit for a proposed Hook Canyon Pump Storage Project. FERC granted the permit later that year. The PHES facility proposed to use an existing lake (Bear Lake in Utah) as the lower reservoir and an upper reservoir to be built on elevated dry land in Hook Canyon, Utah. The proposed upper reservoir was on public lands that belong to Utah Division of State Parks. In December 2007, the Utah Division of State Parks issued a letter stating that it was willing to enter into negotiations with Symbiotics to supply a lease across State Parks property for the Hook Canyon project.

Local environmental groups' concerns included the perceived profitability of the project and the objection to the concept of energy storage itself. They called this project a "perpetual money machine" [21] and made statements such as "This project is NOT renewable energy." and "This is power arbitrage, not power generation." [22]. The opponents were also concerned with environmental impacts such as those on water quality and aquatic habitats. As the confrontation continued, in April 2009 the Utah Governor's Office directed the Division of State Parks to cease negotiations on the leasing of State Parks property for this project. Subsequently, the developer withdrew its license application the following month.

2.4. Lake Elsinore advance pumped storage (LEAPS)

The Elsinore Valley Municipal Water District (EVMWD) in California originally conceived the Lake Elsinore PHES project in 1987. A primary purpose of the project was to stabilize water levels and maintain water quality in Lake Elsinore. The lake was vulnerable to drought conditions that caused water and oxygen levels to drop dramatically on many occasions, causing excessive algal growth, fish kills, and violations of water quality standards. When this occurred, EVMWD was forced to purchase reclaimed water to replenish the lake in order to comply with water quality standards. A PHES facility was expected to increase aeration and improve circulation, preventing algal growth and fish kills, and also to generate income to help defer costs of the purchased water [23].

The EVMWD completed preliminary feasibility studies in 1997, and a private company was formed in 1997 to manage the project. EVMWD and the company completed the environmental impact statement and filed for a license in 2007. FERC has not yet decided whether to grant the license.

Economic viability appears to be a primary cause of delays in this project. Three economic assessment reports all point out that, without revenues from ancillary service, the revenues from power arbitrage alone would not justify the cost of this project. In fact, one of the reports anticipates ancillary service to be the primary source of income for this project [24]. Because the California ISO is still in the process of amending its participation rule to allow non-generator resources in ancillary service markets [25], the economic viability of this project through provision of ancillary services is still uncertain.

2.5. Olivenhain–Hodges

The Olivenhain–Hodges PHES facility is a byproduct of the San Diego County Water Authority's Emergency Storage Project, which is an interconnected system of reservoirs with pipelines and pumping stations designed to make water available to the San Diego region in the event of an interruption in regular water supplies. In the plan, the Olivenhain reservoir and Lake Hodges would be connected with a pipeline and a pump station. Because there is a 196-m difference in the elevation between the Olivenhain reservoir and Lake Hodges, the pump station could function as a PHES facility by using a reversible pump [26]. Because this 40-MW project qualifies as small hydro, FERC approved its license exemption and no environmental impact assessment was required. This project is currently under construction (90% completed) and is expected to start operation in 2010 [27].

The aforementioned case studies reveal a great diversity in the nature of PHES projects and the challenges they faced then and are likely to face in the future. Some were abandoned or delayed due to concerns over environmental impacts, while one was initiated as a means to improve water quality. The Bear Lake/Hook Canyon project was opposed at least partly for concerns over using state parklands for profit, while the LEAPS is delayed because of questionable profitability. The Olivenhain–Hodges and LEAPS cases indicate that PHES could be designed to serve multiple purposes (energy storage, water resource management, water quality protection, etc.). In the Bear Lake case, the environmental groups' objection to energy storage suggests that the value of energy storage in integrating renewable energy is not commonly understood or accepted. Overall, the lack of public awareness of the benefits of bulk electricity storage is a considerable barrier for PHES development.

3. Current developments and new approaches

As of April 5, 2010, FERC had issued 32 preliminary permits in the United States for new PHES facilities and listed 4 applications for preliminary permits pending approval. In examining the designs of these proposals, we found that the proposed projects differ significantly from those of conventional PHES facilities, for which reservoirs were created mostly by damming rivers. Of the 36 proposed PHES projects, 29 are of close-loop/off-stream design. Roughly a quarter of the proposed capacities plan to use underground caverns as lower reservoirs. Some plan to use abandoned quarries or mine pits as upper reservoirs. Less than a quarter of them proposed to dam a river.

As shown in Figs. 3 and 4, these new approaches, including off-stream systems, and those using underground reservoirs, groundwater system and abandoned quarries and mines, signal a substantive change in the direction of pump-hydro storage that addresses many of the historical difficulties in development reviewed in the case studies above. Off-stream designs do not dam rivers and pose fewer problems for aquatic ecosystems. Utilizing abandoned quarries, mines, and underground caverns avoid some impacts to existing water bodies, although the hydrological and environmental interactions still need considerable evaluation for each project. Utilizing groundwater instead of surface water also reduces or eliminates the impacts to fish populations in most situations.

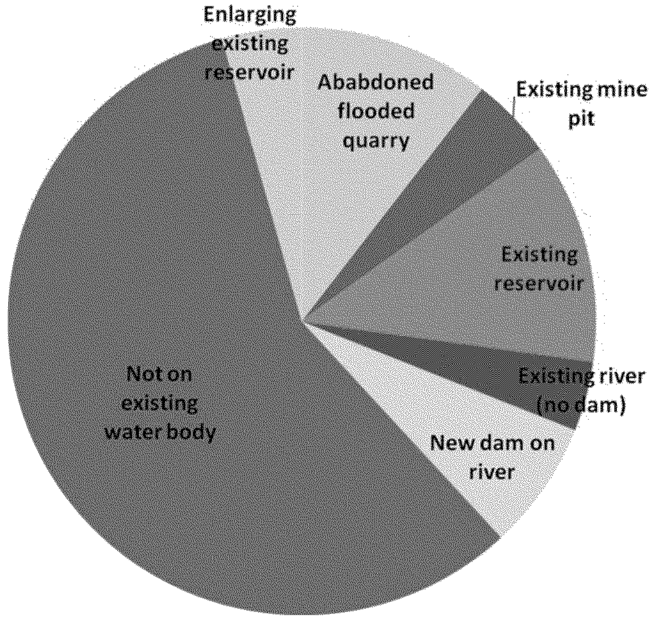

Fig. 3. Upper reservoir design of proposed projects.

One of the new proposed projects, Mulqueeney Ranch in California, is particularly interesting. This project proposes to use recycled wastewater as the water resource for an off-stream PHES system. This innovative approach may have several advantages. Not only would the use of wastewater alleviate concerns for fish populations, but the PHES operation may actually improve the quality of the water it uses to operate. The pumping operation can

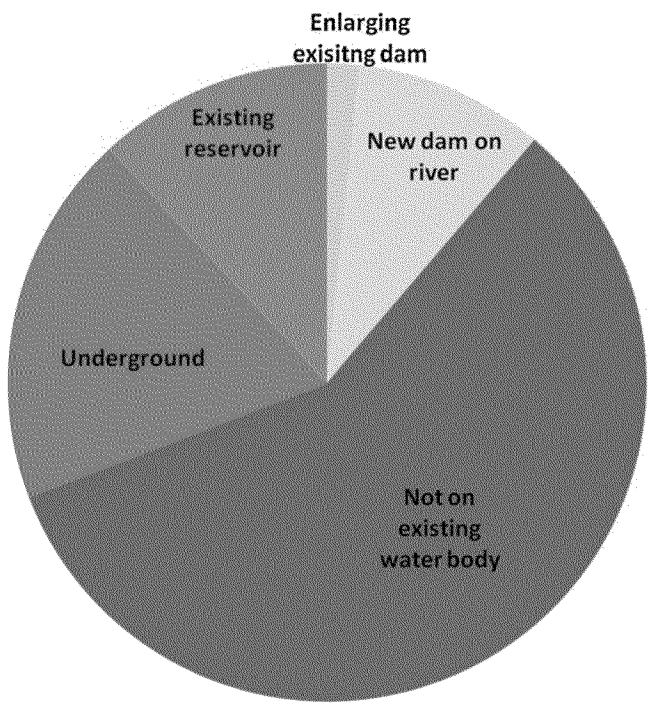

Fig. 4. Lower reservoir design of proposed projects.

be designed to aerate the water, and storage could become an extended aerobic biological treatment. In addition, wastewater treatment plants (WWTPs) are typically located near major population centers, which are demand centers for electricity. Storing electricity nearby would reduce the need for transmission upgrades.

Because such novel wastewater PHES projects may be applicable to other parts of the United States, we briefly examine the design of the Mulqueeney Ranch project as a benchmark for the required minimum WWTP flow rate for PHES.

The 280-MW Mulqueeney Ranch project proposes to divert 500 acre-feet of recycled wastewater per year from the Tracy City WWTP. Five hundred acre-feet per year is equivalent to 0.446 million gallons per day (MGD). According to the U.S. Environmental Protection Agency's Clean Watershed Survey 2004 data, there are 6135 WWTPs in the United States with output flows of more than 0.45 MGD. Certainly, suitable terrains for PHES reservoirs will not always be available near WWTPs. Nevertheless, among the thousands of WWTPs, it is likely that some of them may find suitable PHES opportunities nearby.

4. Future prospects

Perceptions about the potential for adding PHES capacity in the United States have gone through an interesting cycle. The most comprehensive assessment of PHES opportunities conducted in the Unites States was by the Army Corps of Engineers in 1982 [28]. According to that assessment, the United States is endowed with potential PHES sites capable of handling >1000 GW of power. To our knowledge, no comprehensive assessment of PHES potentials has been conducted in the United States since that report. After the development of PHES slowed in the late 1980s, a misconception arose that the United States had run out of feasible PHES sites, a perception that was fairly prevalent [29,30,31,32]. PHES has since largely disappeared from U.S. energy policy. The recent surge of proposed projects indicates renewed interest and increased needs for bulk electricity storage. Today, it is still premature to judge how many of the dozens of proposed projects will ultimately be successful.

Many factors contribute to the uncertain outlook of PHES development in the United States. In recent years, natural gas production from shale formations has been expanding quickly [33]. Increased supply of unconventional natural gas (shale gas) may significantly lower natural gas prices again and render PHES uncompetitive compared to gas for use in peaking power supply. On the other hand, the prospect of a legislated price or cap on carbon dioxide emissions is likely to strengthen the economic outlook of PHES. As intermittent renewable power gains market share, the need for bulk electricity storage will increase, potentially increasing the development of PHES.

Our case studies reveal diversity in the design, and in the environmental and institutional contexts of PHES projects. It is difficult to reach a categorical conclusion about PHES technology overall, in part because each PHES project is unique and must be evaluated on a case-by-case basis. Our review of recently proposed projects in the United States indicates that PHES developers are adapting and responding to the historical drawbacks of PHES and adopting new approaches to reduce environmental impacts. Some of these new approaches include the use of wastewater in PHES systems and the use of off-stream systems to minimize effects on water quality and biodiversity. It is premature to judge whether these new approaches will be sufficient to make PHES more socially acceptable. If properly deployed, however, PHES could play an important role in a low-carbon electricity system in the United States. Policymakers should reconsider and reassess the potential of PHES in the United States, particularly for coupling with intermittent renewable energy sources such as wind and solar power.

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ATTACHMENT 18

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Estimating the value of electricity storage in PJM: Arbitrage and some welfare effects☆

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abstract

Significant increases in prices and price volatility of natural gas and electricity have raised interest in the potential economic opportunities for electricity storage. In this paper, we analyze the arbitrage value of a price-taking storage device in PJM during the six-year period from 2002 to 2007, to understand the impact of fuel prices, transmission constraints, efficiency, storage capacity, and fuel mix. The impact of load-shifting for larger amounts of storage, where reductions in arbitrage are offset by shifts in consumer and producer surplus as well as increases in social welfare from a variety of sources, is also considered.

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1. Introduction

The emergence of wholesale electricity markets in many regions of the United States, together with significant increases in prices and price volatility of natural gas and electricity, have raised the interest in and potential economic opportunities for electricity storage plants. Storage can take advantage of the differences in hourly off- and on-peak electricity prices by buying and storing electricity at times when prices are low, and then selling it back to the grid when the price of energy is greater. Storage also can provide capacity and ancillary services (such as spinning and non-spinning reserves or frequency regulation) as an alternative or complement to energy arbitrage. Large-scale deployment of energy storage, which smoothes the load pattern by lowering on-peak and increasing off-peak loads, will result in a similar smoothing of the price pattern and reduce arbitrage opportunities. Despite its effect of reducing the value of arbitrage, this load smoothing by larger-scale storage can have significant external welfare effects.

In this paper, we analyze four aspects of the economic value of electricity storage deployed in the PJM region.[1] First, in Section 2 we examine the basic relationship among storage efficiency, storage energy capacity, and the arbitrage value of energy storage. Second, in Section 3 we evaluate the accuracy of theoretical energy storage dispatch and the value of arbitrage using perfect foresight compared to a 'real' value capture that considers the uncertainty of future electricity prices. Third, in Section 4 we evaluate the regional and temporal variation in the value of energy arbitrage, examining the impact of transmission constraints, natural gas price variations, and fuel mixes on energy storage economics. Finally, in Section 5 we consider the impact of larger storage devices, examining how the use of energy storage can decrease on-peak and increase off-peak hourly prices diminishing the value of arbitrage, while generating welfare effects for consumers and generators. We also examine the potential for energy storage to help insulate consumers from energy price spikes. While the focus of this work is related to energy arbitrage, energy storage can provide additional societal benefits including improved use of existing generation and transmission and distribution (T&D) assets, benefits from deferred investment in new generation

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[1] Parts of the work in this paper extend some of the analysis and ideas in Jenkin and Weiss (2005).

capacity and T&D, and helping to integrate renewable energy resources into the power system.

2. Arbitrage value of small amounts of electricity storage in PJM: the impact of hours of storage and efficiency

One of the best-understood and studied applications of energy storage is the use of 'small device' energy arbitrage—the ability to buy low and sell high, where the device is assumed to be small enough that its charges and discharges do not affect the price of electricity. This type of 'price-taker' analysis often assumes perfect optimization of small devices facing known prices. Examples of this type of analysis that have been applied to wholesale electricity markets include Graves et al. (1999), Walawalkar et al. (2007), and Figueiredo et al. (2006). Other recent studies of electricity storage that cover a broader range of applications include Eyer et al. (2004) and EPRI (2003).

A storage device captures arbitrage value by storing low-cost energy and then reselling that energy during higher-priced hours. A storage device is typically characterized by its power capacity (MW), its energy capacity (MWh), and roundtrip efficiency. The energy capacity of a storage device may also be rated by the number of hours of full power output, which is the convention used in this paper. Some storage devices have energy capacities of less than an hour, such as flywheels and batteries designed primarily for ancillary services such as frequency regulation or spinning reserves. Larger devices used for energy arbitrage, such as pumped hydroelectric storage (PHS), compressed-air energy storage, or certain large batteries, may store enough energy to accommodate a full day's peak demand period of 8 h; and, in some cases, have been built with more than 20 h of discharge capacity.[2]

We first estimated the historical annual value of arbitrage for a small storage device in PJM from 2002 to 2007. The PJM Interconnection is a regional transmission organization serving about 51 million people in the eastern U.S. with a 2007 peak demand of about 139 GW. PJM operates a series of centralized multi-settlement markets for energy, ancillary services, and capacity on a day-ahead and real-time basis. For each year, the operation of the storage device was optimized to maximize arbitrage profits against hourly load-weighted average marginal energy price data obtained from PJM. The optimization was conducted two weeks at a time, assuming perfect foresight of future hourly electricity prices during each two-week period. This use of a two-week optimization horizon allows for both intra- and inter-day arbitrage opportunities, including greater charging during weekends, because hourly electricity prices often tend to be lower than during the week. Optimizing over a two-week period also reflects the fact that a storage operator would not be realistically expected to make dispatch decisions in anticipation of prices many weeks in the future. To ensure energy stored in the device at the end of each two-week period has 'carryover value', each optimization was done with a 15-day planning horizon to determine the dispatch of each two-week period. Otherwise, the operator would fully discharge the device by the end of each two-week period, which would not reflect actual device operation. Because of the price-taking assumption, the model is a linear program which we formulate in GAMS 21.7 and solve using CPLEX 9.0. Appendix A discusses the formulation of our model in greater detail.

We assumed for these initial calculations an 80% roundtrip efficiency, which is at the upper range of actual storage devices currently available (such as the Bath County PHS plant in PJM, which has an 80.3% efficiency ASCE (1993)). We discuss the sensitivity of our results to storage efficiency in more detail later in this section. As a result 10 h of charging is required for each 8 h of discharging.[3] The value of arbitrage for each two-week period was then summed over the year to provide annual values for the value of arbitrage on a $/kW-year basis. Fig. 1 shows hourly energy prices during a sample one-week period in 2006 and the optimal hourly operation of a 12-hour storage device.[4] As expected, the dispatch pattern follows the prices with energy stored when prices are low and sold when prices are higher. For a price-taking device, if the device is dispatched to charge or discharge in a given hour, it is optimal to dispatch it to the lesser of its power or available energy capacity. It is important to note that hourly charge and discharge patterns in different days are similar but not the same, showing that inter-day and weekend effects matter.[5] Fig. 2 shows the historical value of storage as a function of hours of storage. The value of arbitrage in PJM has varied significantly during this time period ranging from about $60/kW-year in 2002 (for a 12-hour device) to more than $110/kW-year in 2005. We discuss the reasons for these observed changes in value in section 4.

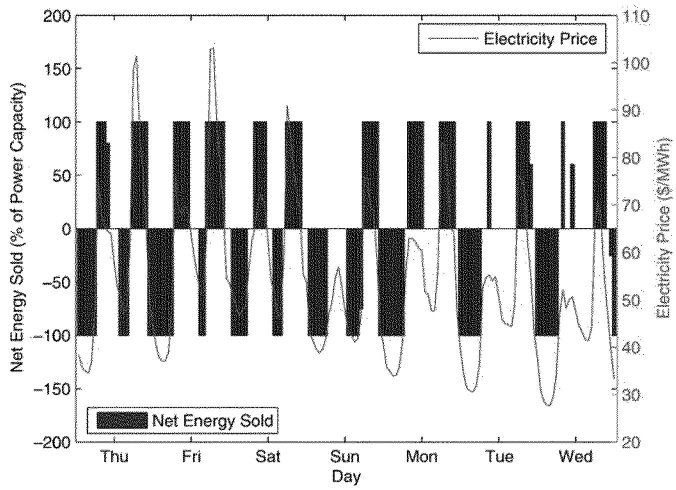

Fig. 1. Electricity prices and the optimal hourly dispatch of storage device during one week in 2006.

Figs. 3 and 4 provide additional insight into the relationship between storage value and size. Fig. 3 illustrates that most of the arbitrage value in storage comes from intra-day arbitrage, with more than 50% of the total capturable value derived from the first 4 h of storage.[6] Additional value is provided by longer-term storage, including the ability to perform inter-day arbitrage as well as charge more during the weekend and discharge during the following week; 8 h of storage captures about 85% of the potential value, while 20 h of storage captures about 95% of potential value.[7] Fig. 4 illustrates the marginal value of each additional hour of storage, which falls roughly linearly to about 8 h, with additional storage providing relatively little incremental arbitrage opportunity.

The data in Figs. 2–4 can be used to evaluate the optimal size of a storage device for each technology, which will depend on the fixed and variable cost characteristics of the device, as well as efficiency. There is no universal optimal size of storage, because it will depend on the technology and planned applications. Even if only arbitrage is considered, the marginal cost of the next incremental hour of storage can be expected to vary widely by technology, although technology costs and cost structure are not addressed in this paper.[8]

[2] See Denholm and Kulcinski (2004) for further discussion of this topic.

[3] We assume throughout our analysis that storage devices have the same input and output power capacity.

[4] For reasons of clarity Fig. 1 only shows prices and dispatch for one week, although the optimization is done with a two-week horizon as described above.

[5] Graves, Jenkin and Murphy (1999) observed similar operational behavior.

[6] In all cases the optimization horizon remains 15 days.

[7] See also Graves, Jenkin, and Murphy (1999).

[8] To illustrate this idea, consider PHS, which often has more than 20 h of storage. Part of the reason for the large capacity is that the marginal cost of increasing the size of the reservoir may be small relative to the overall capital costs. Any planned applications beyond arbitrage, such as backup capacity, also may be important.

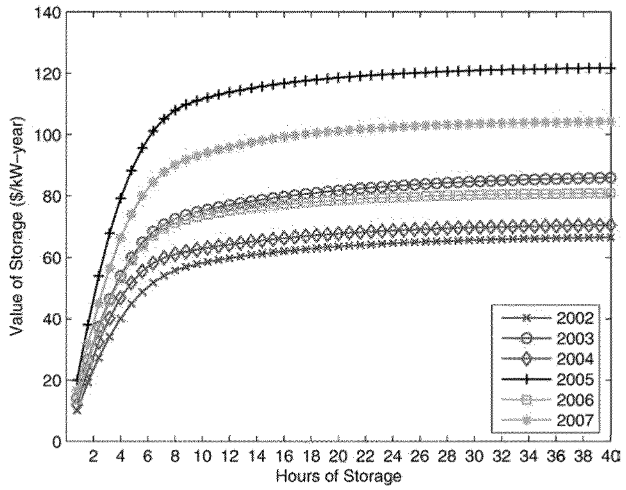

Fig. 2. Annual arbitrage value of a price-taking storage device as a function of hours of storage.

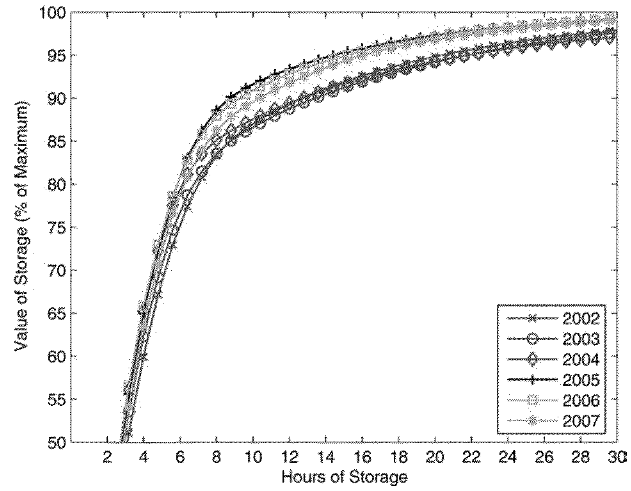

Fig. 3. Potential annual arbitrage value captured, as a percentage of maximum theoretical value.

As noted earlier, the storage efficiency of 80% assumed in Figs. 2–4 is at the upper range of actual storage devices currently available. The efficiency of a modern PHS device is in the range of 65–85%, while large batteries (such as sodium-sulfur and vanadium redox) have efficiencies of about 65–75%, as discussed by ASCE (1993) and Denholm and Kulcinski (2004). Fig. 5 illustrates the relationship between storage capacity[9] and storage value for systems with a range of efficiencies using average hourly PJM prices in 2006. Efficiency can have a significant impact on the arbitrage value of storage. For example, increasing the efficiency of a 20-hour device from 70% to 80% results in a more than 30% increase in arbitrage value from $60/kW-year to $80/kW-year. The reason for this multiplier effect is that a more inefficient device not only needs to charge more hours (for a given number of hours discharged), but these added hours are typically more expensive.[10] Fig. 5 also shows the number of hours of storage for each efficiency level at which 90% of the potential maximum value can be captured, showing that between 9 and 10 h of storage is sufficient for the range of efficiencies examined.

3. Impact of imperfect forecasting on energy arbitrage value

One of the limitations of basic arbitrage analysis using historical price data is that it often assumes, as we did in Section 2, the optimal operation of the storage device with perfect foresight of hourly energy prices. This approach provides an upper bound on the value of storage. An important question is how close a real operator might come to capturing the theoretical value obtained by perfect foresight. We evaluated the difference between an optimal hourly dispatch and a more realistic approach that does not include any foresight—just knowledge of recent past prices, which is then used to 'guess' the hourly dispatch for the near future. Specifically, we optimized the device in any given two-week period using hourly price data for the two previous weeks (which would, of course, be known at that point). Although hourly charge and discharge operations were made using the previous two weeks' price data, the arbitrage value was then estimated using actual hourly prices for the two-week period being optimized. In other words, this method 'backcasts' an optimal dispatch for the previous two weeks and applies that to the current two-week period. Each of these two-week estimates was then

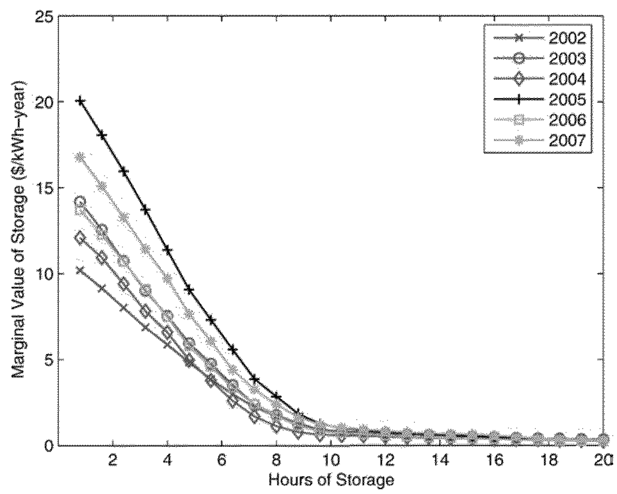

Fig. 4. Annual marginal arbitrage value of energy capacity of a storage device.

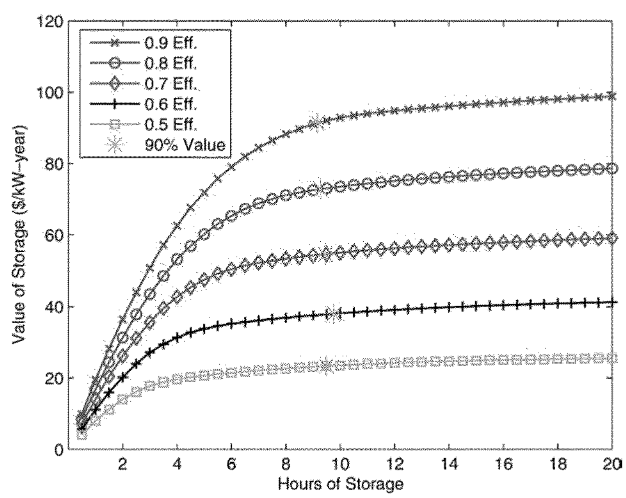

Fig. 5. Annual arbitrage value of a storage device with different roundtrip efficiencies in 2006.

[9] Because the roundtrip efficiency of the storage device is changed, it is important to note the distinction between storage and discharge hours. As an example, in our simulations, a 50%-efficient device requires two hours of storage for one hour of discharge, whereas an 80%-efficient device requires 1.25 h of storage for 1 h of discharge. As such, all figures use discharge hours on the horizontal axis.

[10] This result does depend on our assumption that a storage device has the same power capacity for charging and discharging. If the charge power capacity is increased, then a more a inefficient device would not need to increase the number of hours it charged for a given discharge.

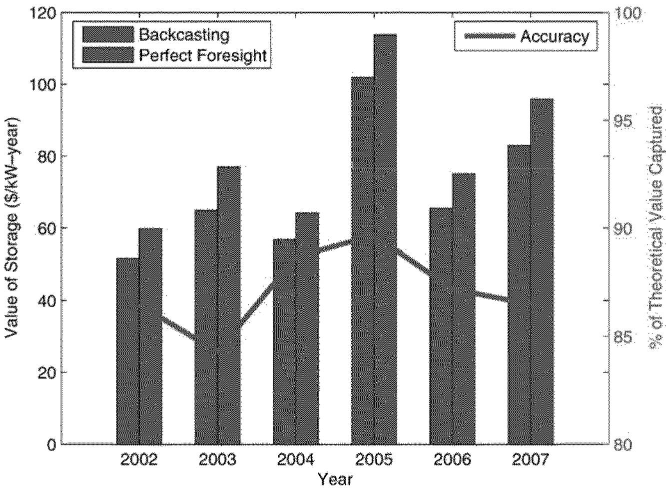

Fig. 6. Annual arbitrage value captured by using two-week backcasted dispatch rule versus perfect foresight.

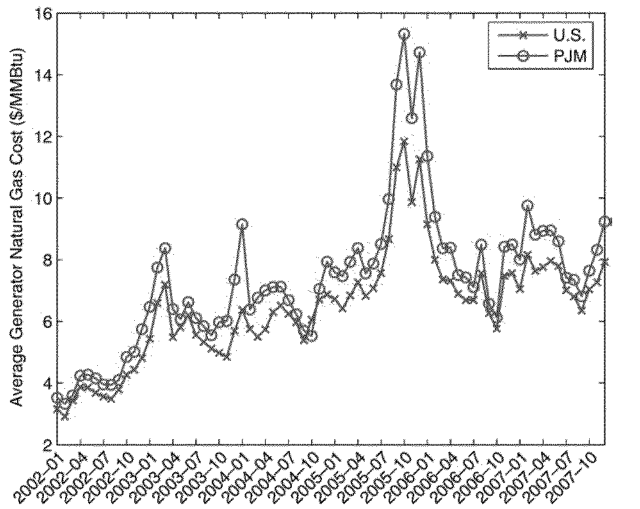

Fig. 7. Average monthly price of natural gas paid by electricity generators in the U.S. and in PJM.

aggregated to provide estimates for the entire year, and these annual values were compared to the theoretical maximum with perfect foresight of prices.

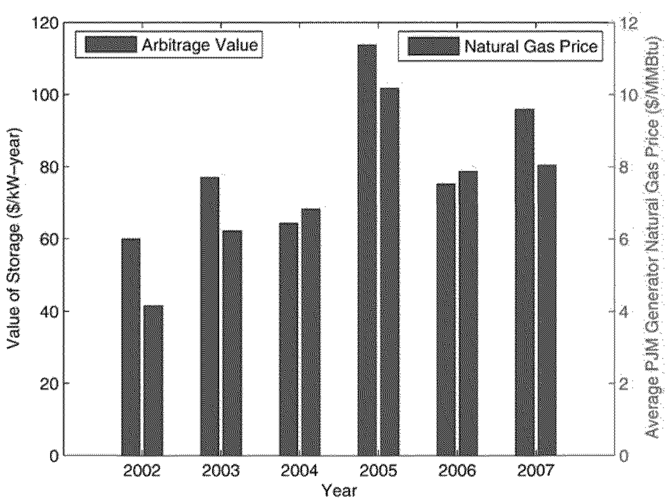

Fig. 8. Annual value of arbitrage and annual average price of natural gas paid by generators in PJM.

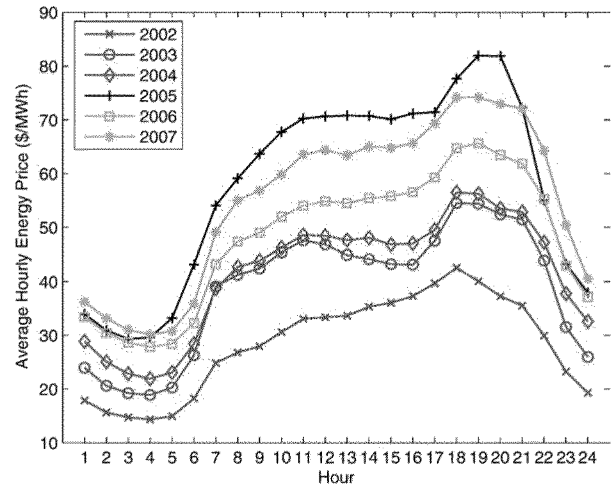

Fig. 9. Annual average hourly price of electricity.

Fig. 6 illustrates the difference between the perfect foresight dispatch and the two-week backcasting approach for a device with 12 h of storage. In each of the six years evaluated, the backcasting approach captured about 85% or more of the potential arbitrage value. This approach is successful because the hourly operation and value of energy storage is strongly based on historical price and load patterns over a variety of different time-frames, which are to a large extent predictable. The relevant patterns are: (i) the diurnal (or daily) price/load pattern, with fairly predictable hourly off- and on-peak periods, and (ii) the weekday/weekend relationship, with weekends tending to have somewhat lower energy prices. Although the diurnal hourly price patterns differ significantly on a seasonal basis, such differences are largely captured because our backcasting approach only uses a two-week lag.

The simulated two-week backcasting approach does not capture changes in prices that result from nearer-term changes in weather and other short-term load and supply effects, such as generator availability. We would expect it would be relatively straightforward to refine this type of backcasting to substantively increase the value captured e.g., through the use of near-term weather forecasting and the more refined dispatch rules. An example of this is the fact that hourly day-ahead load forecasts are typically within 5% of actual real-time loads—made possible by using historical load patterns and weather forecasting (see a discussion of this fact in PJM (2005)). Such hourly load estimates can, in turn, be used to provide price estimates.

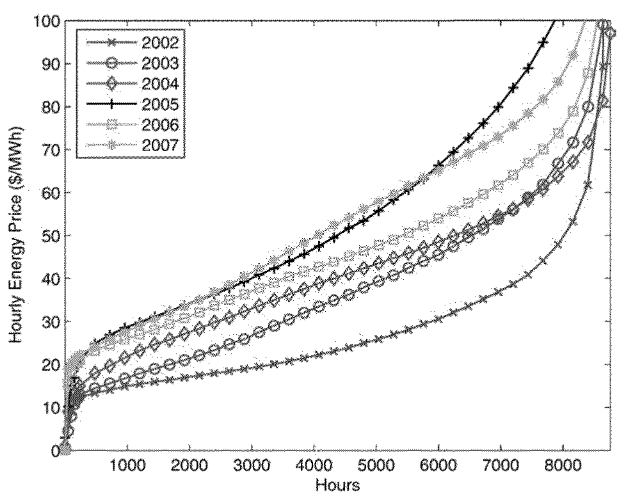

Fig. 10. Hourly electricity price duration curve.

We provide this example partly to justify the value of a perfect foresight optimization in obtaining a reasonable estimate of storage value in the price-taking device analysis presented here, and in the large device analysis discussed in Section 5. As mentioned above, the no-foresight backcasting approach used here represents a lower bound of value capture that will almost certainly be enhanced by basic forecasting.

4. Variation in the arbitrage value of storage in PJM: the impact of temporal and regional variation in fuel and electricity prices

As illustrated in the previous sections, the value of storage varies from year to year. In this section we demonstrate that these differences are due partly to variations in fuel price, marginal hourly fuel mix[11], and transmission constraints. Evaluation of these factors provides an explanation of historical variation in storage value, and can help determine the potential variation in storage value in the future.

Because hourly on-peak electricity prices are often set by natural gas generation, it can be expected that increases in natural gas prices should lead to increases in both hourly on-peak electricity prices and the value of storage. Fig. 7 shows the historical monthly price of natural gas sold to electric utilities in the PJM area and the U.S. between 2002 and 2007, based on data from the U.S. Department of Energy's Energy Information Administration.[12] Prices of natural gas have increased from about \$3–\$4/MMBtu in 2002 to about \$6–\$8/MMBtu, or more during the past few years. It is important to note that data for 2005 is slightly aberrant—both for the price of natural gas and the value of electricity storage—due partly to the impact of hurricanes on natural gas supplies in the U.S.[13]

Fig. 8 illustrates the historical relationship between natural gas fuel prices and arbitrage value. The arbitrage value is derived from Fig. 2, assuming a 12-hour device. It is evident that the average value of arbitrage for storage in PJM has increased significantly with increased gas prices, from about \$60/kW-year in 2002 to about \$80–\$100/kW-year, or more in recent years. This 30% to 60% increase in the arbitrage value of storage compared to 2002 is substantive, though significantly less than the more than 100% increase in natural gas prices during the same period. The small increase in the value of storage (relative to the increase in the price of natural gas) can be explained, in large part, by other changes in the PJM market that affected energy prices. The actual value of arbitrage depends on the relationship between off- and on-peak prices, which will depend on the underlying fuel mix of the supply curve and the hourly off- and on-peak loads. In general, storage will be more valuable in regions where nuclear, hydroelectric, and coal are available for off-peak electricity generation.[14]

The relationship between arbitrage values and off- and on-peak price differentials can be observed in Figs. 9 and 10. The increase in off-peak prices between 2002 and 2005 partially reflects the increase in coal prices, which nearly doubled during this period. Between 2003 and 2004 the arbitrage value decreases despite a small increase in gas prices, due partly to these significant increases in off-peak prices. In contrast, from 2006 to 2007, the on-peak hourly prices and arbitrage value increase despite nearly flat natural gas prices. Explanation of this requires an examination of the actual fuel mix providing off- and on-peak energy.

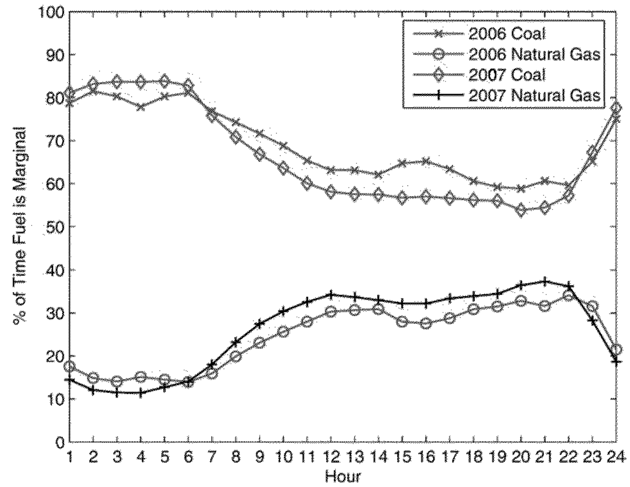

Fig. 11. Percent of time in which coal and natural gas were marginal fuel in each hour for 2006 and 2007.

Fig. 11 illustrates the fraction of the marginal fuel mix provided by coal and natural gas during each hour of the year in 2006 and 2007. During this time period, the fraction of the marginal fuel mix derived from coal decreases during on-peak hours with an increase in the percentage of time natural gas sets the margin, resulting in higher on-peak prices. This occurs even with no significant change in the price of natural gas, because natural gas is significantly more expensive than coal.[15]

It is important to note that all previous arbitrage estimates have used load-weighted average hourly PJM prices. Within PJM, the value of arbitrage can be expected to vary by location due to transmission constraints and losses; and, accordingly, the value of arbitrage may be considerably higher at different locations than the arbitrage values calculated using load-weighted average prices. Fig. 12 illustrates the variation in annual arbitrage value for different bus locations within PJM in 2006, assuming a device with 80% efficiency and 16 h of storage capacity. While the average value of arbitrage in PJM for 2006 was \$77/kW-year, the value at individual buses can be as high as \$105/kW-year, corresponding to an almost \$30/kW-year premium.[16]

The analysis presented in these sections represents a 'static' valuation of energy storage arbitrage. Increased transmission capacity potentially can decrease the regional differences in value, while load growth in congested areas (without corresponding increases in transmission capacity or local generation) will tend to increase arbitrage opportunities. Storage may also potentially provide an alternative or complement to transmission to relieve congestion, although the economic evaluation of this application is extremely site-specific.[17]

5. Impacts of large-scale storage

As the amount of storage in a system increases, the arbitrage value on a \$/kW-year basis will decrease as increasing amounts of on-peak load is shifted to off-peak periods, resulting in lower on-peak prices and higher off-peak prices, thereby reducing the arbitrage value of

[11] The marginal hourly fuel mix will depend, primarily, on where the supply curve and load intersect.

[12] The natural gas prices for PJM are actually the cost of natural gas sold to electric generators averaged over New Jersey, Maryland, and Pennsylvania.

[13] While hurricanes Katrina and Rita did have a significant effect on natural gas supplies and the price of natural gas, these prices were high absent these events, with average prices at more than \$8/MMBtu for more than six months in 2005.

[14] It is of interest to note that while off-peak prices are largely set by coal, it is never set by lower-cost nuclear power—despite the fact that more than 33% of total generation in PJM in 2007 came from nuclear generation.

[15] It should be noted that other more expensive fuels, such as oil, also contribute to setting the margin during peak periods (primarily in the summer), and increases in the price of oil also drove the increase in on-peak electricity prices.

[16] This corresponds to the Bedington bus in PJM (the darkest red point on the map). Similarly, in 2007, while the arbitrage value based on average PJM prices was \$99/kW-year, the arbitrage value at the same bus is \$137/kW-year—giving a larger premium.

[17] One interesting idea discussed by Eyer et al. (2005) is that storage valuation should account for the fact that a relocatable modular storage device might be moved to various locations during its asset life.

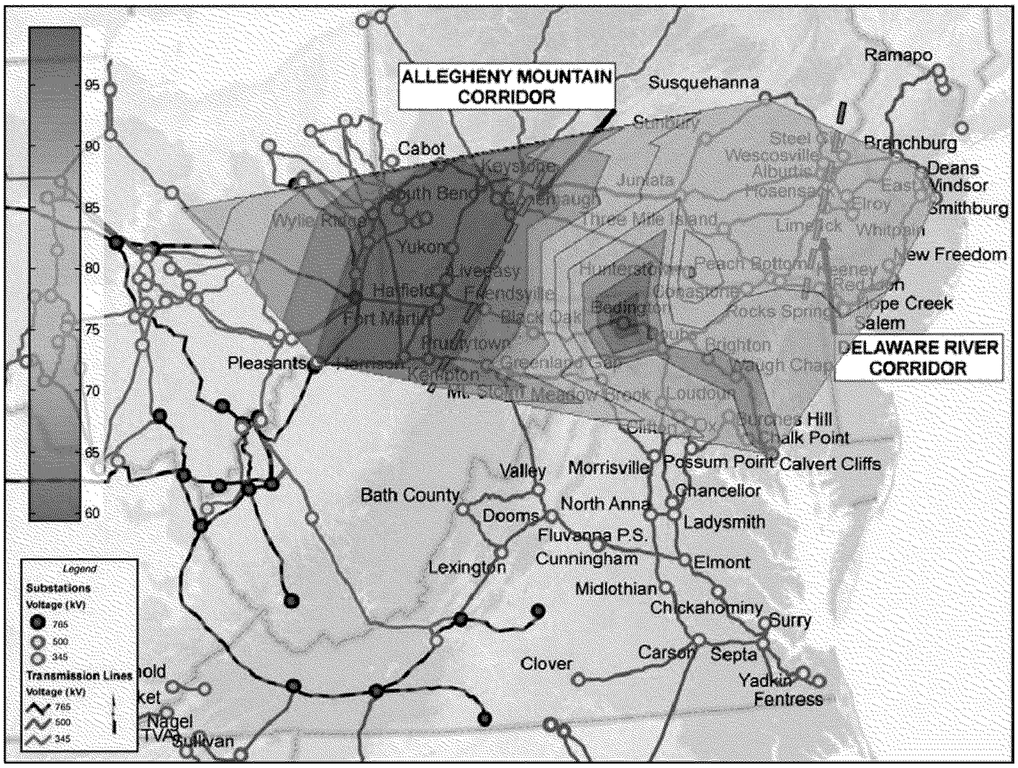

Fig. 12. Annual arbitrage value at 47 bus locations within PJM in 2006.

storage. Fig. 13 provides an example of actual hourly price/load data for a single month (June 2006) and an ordinary least squares (OLS) estimate of a linear relationship between price and load, which shows a strong fit. The price/load relationship is driven by where the inelastic load intersects the generation supply curve, and as such the price/load points 'map out' the supply function. The net result of large amounts of storage will be a flattening of the diurnal generation-load profile[18] and a corresponding flattening of prices. Theoretically, entry by storage devices should occur until all profitable opportunities to buy inexpensive energy off-peak and sell expensive energy on-peak are arbitraged away.

5.1. Impacts of large-scale storage on arbitrage value

We analyze the effects of large-scale storage by modeling the operation of a large storage device[19], which accounts for the effect that its charging and discharging has on the price of energy. We assume that there is a non-decreasing linear relationship between the price of energy and generating load, such as the one shown in Fig. 13. Because of seasonal differences in fuel costs, generation mix, and loads we assume that each month has a different linear price–load relationship, and estimate the parameters of the function for each month by restricted least-squares[20] using the actual price and load data from that month. We model the storage device's hourly operations by maximizing arbitrage value using the same two-week optimization horizon discussed in Section 2, and further assume that the storage operator knows the parameters of the price relationship and load for each two-week period with perfect foresight.

Thus, our analysis assumes that the storage operator perfectly anticipates hourly electricity prices and the effect that hourly charging or discharging would have on those prices. Because the price-load relationship is assumed to be linear non-decreasing, the resulting optimization is a convex quadratic program, and first-order necessary conditions are sufficient for a global optimum. The model was formulated in GAMS 21.7 and solved using MINOS 5.5. Appendix A gives the explicit formulation of our model and discusses it in more detail.

The operation of the storage device with prices varying in response to generating loads will be largely similar to that with prices fixed, with the storage device charging when prices are low and discharging when prices are high. Fig. 14 contrasts electricity prices and the differences in the operation of a 1 GW device with 12 h of storage over a sample week-long period in 2006, with varying and fixed prices.[21,22] The prices show the expected smoothing behavior with lower prices on-peak and higher prices off-peak due to changes in the generating load resulting from operation of the storage device. The operation of the storage device also shows changes. We saw in Fig. 1 that with fixed prices the device is always operated at the lesser of its energy and power capacity when discharging or charging. With varying prices, charges and discharges are sometimes curtailed when the price impacts reduce the marginal arbitrage value to zero. In other cases, such as on Friday morning, the device does not operate at all with varying prices, even though it would with fixed prices. While 1 GW is a large amount of storage, it is worth noting that a number of PHS facilities in the U.S. are 1 GW or greater, for example the Tennessee Valley Authority's Raccoon Mountain PHS plant can continuously discharge at 1.6 GW for 22 h.

Fig. 15 summarizes the value of 1 GW of storage, showing the percentage of potential value that can be captured if prices respond to generating loads, compared to assuming the prices are fixed but

[18] It should be noted that absent time-variant retail rates such as real-time pricing or time-of-use rates, the load profile will remain the same because demand does not respond to the use of storage. The generation profile will, however, change in response to charging and discharging of the storage device.

[19] This analysis can be generalized to multiple storage devices that collusively act to maximize total arbitrage value.

[20] The constraint on the OLS estimate, which is always non-binding, is that the price-load relationship be non-decreasing.

[21] Although Fig. 14 only shows prices and dispatch for one week, the optimization was done using two-week planning horizons.

[22] To make the two cases comparable, the fixed prices were derived from the price-load relationship using the actual system load.

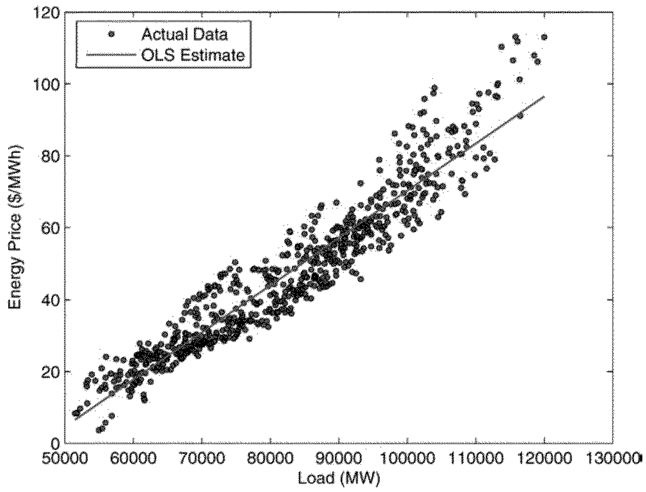

Fig. 13. Hourly price–load relationship in June 2006.

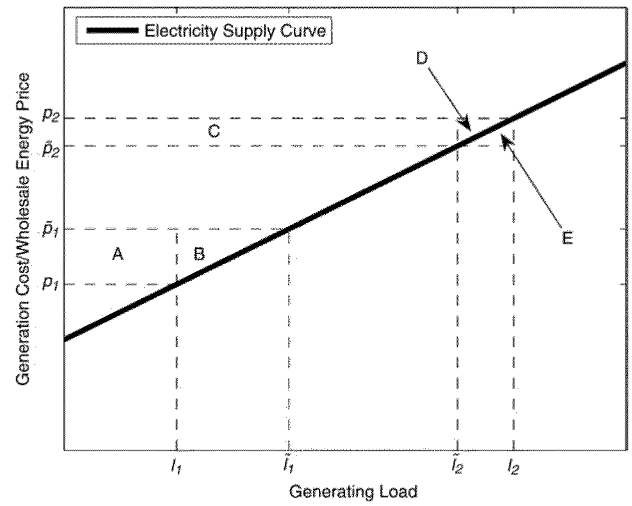

Fig. 16. Linear price–load relationship.

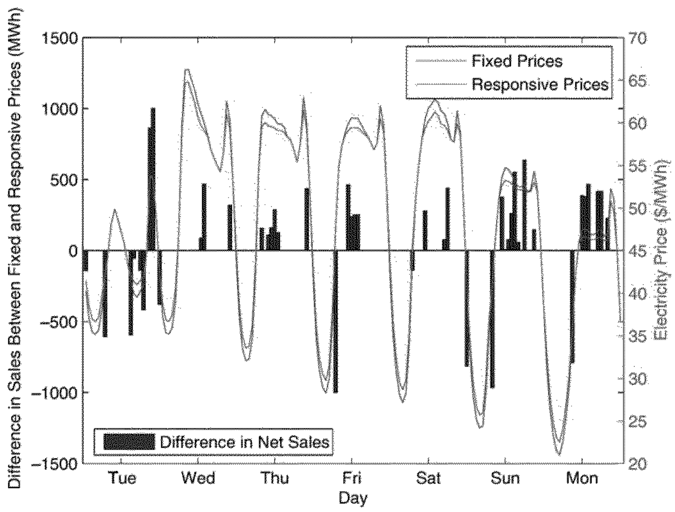

Fig. 14. Electricity prices and difference in net sales with fixed and responsive prices for one week in 2006.

follow the same linear price–load relationship. Our analysis shows that the value of storage would have been diminished relative to a price taker—by approximately 10% during the past three years, but

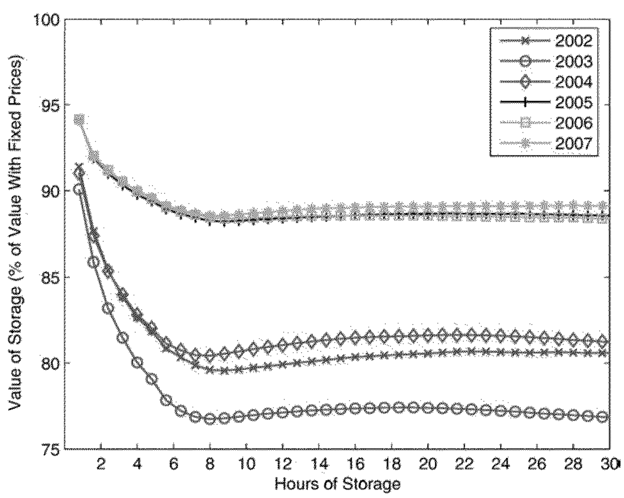

Fig. 15. Arbitrage value captured with price responsiveness, as a percentage of value with fixed prices.

more than 20% for some earlier years. The reason for the differences across the years stems from the fact that PJM grew between 2002 and 2007 by adding adjacent control areas. As such, a 1-GW device represents a smaller device relative to the size of the system in 2007 as opposed to 2002. In 2002, for instance, the peak load was 63,761 MW with an average load of 35,470 MW, whereas in 2007 these values were more than doubled to 139,427 MW and 82,667 MW, respectively. Because the off- and on-peak price difference did not change in proportion to the size of the load, a 1-GW device would have a much larger price-shifting effect in 2002 than in 2007. This is reflected in the fact that the value of a large storage device is diminished much more in the earlier years compared to the later ones.

5.2. External welfare effects of large-scale storage

In addition to the arbitrage value captured by the storage device owner, consumers and generators will also benefit and lose from the use of energy storage. Reduced on-peak and increased off-peak prices to consumers can result in consumer surplus gains, stemming from lower energy costs to consumers. Because of the relationship between energy prices and generation, an increase in generation off-peak (due to energy storage) with an offsetting decrease in generation on-peak (due to meeting some load with energy discharged from the storage device) will result in increases and decreases in prices off- and on-peak. However, because consumer demand tends to be significantly lower off-peak, the decrease in consumer surplus from the higher price that is paid off-peak will be more than offset by an increase in consumer surplus on-peak due to decreased generation needs and a corresponding drop in the price of energy. Conversely, generators will generally see their profits decrease from use of a storage device, because the increase in profits off-peak will be offset by the drop in profits on-peak.

Fig. 16 demonstrates this effect for a single paired hourly charge/discharge cycle of a storage device. The line represents the marginal cost of electricity generation as a function of generation, which we assume sets the wholesale price of electricity. Without any charging or discharging, the load and energy generated off- and on-peak are given

Table 1
Social value of storage device with 4 h of storage ($ million)

Year	Arbitrage value	ΔCS	ΔPS
2002	26.8	16.8	-14.3
2007	47.3	22.7	-20.2

Table 2
Social value of storage device with 8 h of storage ($ million)

Year	Arbitrage value	ΔCS	ΔPS
2002	37.0	21.5	-17.3
2007	64.9	27.3	-23.4

Table 3
Social value of storage device with 16 h of storage ($ million)

Year	Arbitrage value	ΔCS	ΔPS
2002	42.1	26.3	-21.7
2007	73.7	34.6	-30.3

by l_1 and l_2, respectively, and the price of energy would be p_1 and p_2 off- and on-peak, respectively. When the storage device charges off-peak and discharges on-peak, consumer demand remains the same, but the generating load increases to l_1 off-peak and decreases to l_2 on-peak, with commensurate changes in the energy price off- and on-peak to p_1 and p_2, respectively. As a result of these changes in prices and generation quantities, there will be changes in consumer and producer surplus. Consumer surplus decreases by the rectangle labeled A off-peak due to the higher price of energy, but increases by the sum of the areas labeled C, D, and E on-peak due to the lower on-peak price of energy. Producer surplus increases by the sum of the areas labeled A and B off-peak due to higher generating loads and an increase in the energy price, and decreases by the areas labeled C and D on-peak. Adding these terms, the effect of the charge/discharge cycle is that the sum of consumer and producer surplus increase by the sum of the areas labeled B and E.

We analyze the welfare effects of using a large storage device, assuming the same linear relationship between prices and generating loads and that the storage device is operated to maximize arbitrage value (i.e., the storage operator does not consider external welfare effects). The surplus calculations are based on the changes in prices and generation shown in Fig. 16. In computing producer surplus changes we assume that generators behave competitively and prices reflect the actual marginal cost of generation. Tables 1–3 summarize these welfare effects for a 1-GW storage device with 4, 8, and 16 h of storage with 80% efficiency in 2002 and 2007. Our results show that the external welfare effects for consumers and producers are on the same relative scale as the arbitrage value. Moreover, although there are large wealth transfers from generators to consumers, the fact that the increase in consumer surplus is greater than producer surplus losses shows that there are net social welfare gains stemming from the load-shifting effects of large-scale storage.

5.3. Impacts of large-scale storage on reducing consumer impacts of electricity price shocks

Large-scale storage can also potentially help mitigate the impact of price volatility resulting from supply disruptions, such as that which occurred with hurricanes Katrina and Rita in 2005. While natural gas prices were high that year in general, supply disruptions resulted in transient jumps in natural gas and electricity prices. Fig. 17 shows price and load data for two days before and after Hurricane Katrina landed, which are one week apart (August 25 and September 1, with the

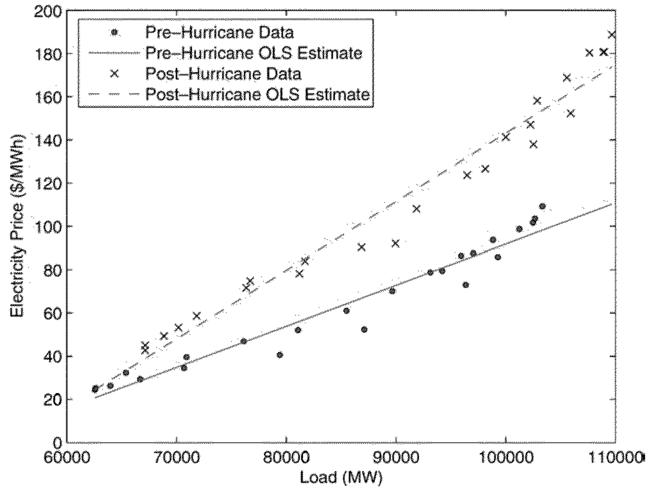

Fig. 17. Hourly price–load data and OLS estimate of relationship before and after Hurricane Katrina.

hurricane hitting New Orleans on August 29). While the load pattern was similar for both days, it is clear that the price–load relationship has changed, in that there is a much greater off- and on-peak price difference, with a corresponding increase in the slope of the price–load relationship after the hurricane. As such, one effect of the hurricane was to increase electricity costs for consumers in PJM (as well as other parts of the US in which natural gas-fired generation had set the margin). One potential impact of the load-shifting effect of large-scale storage is that it could help to mitigate the effect of these price shocks by reducing the increase in on-peak electricity prices. While there would be a corresponding increase in off-peak prices when the storage device is charged, there would likely be large net increases in consumer surplus because this price increase is applied to a smaller load than the on-peak price. Moreover, because of the steeper price-load relationship post-hurricane, the changes in off- and on-peak prices after the hurricane will be larger than they would have before.

We examined this potential benefit of large-scale storage by using the price–load relationship for each of the two days, simulating the operation of a 1-GW storage device with 8 h of storage. The simulation was done for each day separately, and only optimized over the one day. As before, the storage device is assumed to be a profit-maximizer (i.e., it does not consider consumer or producer surplus changes). Table 4 summarizes the arbitrage value and consumer and producer surplus changes before and after the hurricane. Our results show a more than 70% increase in arbitrage value after the hurricane, stemming from the larger off- and on-peak price difference. The analysis also shows an increase in the consumer surplus change of about 70%, due to the increased price-shifting ability of a large storage device and its ability to partially insulate consumers from higher on-peak prices.

Our analysis of the load-shifting effects associated with large-scale storage is illustrative to the extent that we have used a linear price–load relationship. This assumption of a linear relationship yields a convex quadratic programming problem, which makes the analysis tractable. Figs. 13 and 17 demonstrate that using short time frames of a month or less to fit the linear relationship can provide a good fit to the data.

Table 4
Arbitrage value and changes in consumer and producer surplus before and after hurricane ($)

Day	Arbitrage value	ΔCS	ΔPS
Pre-hurricane	345,000	188,000	-172,000
Post-hurricane	590,000	320,000	-295,000

6. Discussion and conclusions

Wholesale electricity markets in many regions make it possible to evaluate the potential arbitrage value of energy storage in many parts of the country and around the world. Our analysis shows that there are a number of drivers behind the value of arbitrage including location, fuel price, fuel mix, efficiency, and device size, as well as the hourly load profile. In the case evaluated here, the annual value of arbitrage for a price-taking storage device in PJM with an 80% roundtrip efficiency and a storage time of 12 h was found to have increased from about $60/kW-year to $110/kW-year or more in recent years. These estimates of arbitrage value based on average PJM prices undervalues the actual potential regional value of arbitrage, with our analysis showing that certain buses within PJM have an additional premium of $20/kW-year to $30/kW-year or more due to transmission congestion and losses.

As expected, the marginal arbitrage value (on a $/kW basis) of the next hour of storage drops sharply as a function of energy capacity, with the knee of the curve at about 8 h. There is no one optimal number of hours of capacity for a storage device, rather, it will vary by technology and applications. Even if only arbitrage is considered, different technologies may have different fixed and variable costs (for both energy and power capacity) and efficiencies.

Capturing value through energy arbitrage requires short-term forecasting of hourly electricity prices to appropriately charge and discharge to maximize price differentials. Perfect foresight of energy prices appears to be a reasonable approximation of actual value capture, based on our simple two-week backcasting-based dispatch capturing about 85% or more of the theoretical value. Moreover, this value would be expected to improve significantly if simple forecasting techniques are added.

The observed annual variation and general increase in arbitrage value between 2002 and 2007 is driven by the difference in hourly off- and on-peak electricity prices, which themselves are driven by the underlying cost of fuel and the fuel mix, which in turn will depend on the load. The increase in natural gas prices is the main driver, though changes in the amount of time natural gas provides the marginal generation fuel on-peak and changes in coal and oil prices also will be important.

In PJM and other energy and capacity markets a storage device may also be eligible for capacity payments in addition to the energy arbitrage value estimated above. Such payments are designed to encourage additional capacity where price caps limit energy prices. The value of such payments is highly uncertain, and so we have chosen to mention them here as a potential adder rather than estimate them, although they may be substantial.[23] Another source of value from storage can come from co-optimizing between different markets, such as energy arbitrage and ancillary services (e.g., frequency regulation and spinning reserves)—though these have not been considered in this paper.

The introduction of energy storage on a large scale has the potential to increase off-peak prices and decrease on-peak prices, thereby decreasing the value of energy arbitrage. Arbitrage is not, however, the only important source of value, especially for devices that can shift load and prices. Specifically, despite this decrease in arbitrage value, large-scale storage can potentially provide other social welfare improvements, including improved utilization of the electricity infrastructure, deferred need to build generation and T&D assets, and the ability to reduce congestion. The value of these benefits can be significant, though are extremely site-specific and some of these benefits are hard to quantify. We demonstrated that there can be large shifts in consumer and producer surplus, associated with increases in prices to consumers when the device is charged and decreases in prices when discharged. Because the on-peak load is greater than off-peak load the use of large amounts of storage can lead to significant net increases in consumer surplus, and associated decreases in costs to end users. We also showed that this welfare-shifting effect can provide a partial risk mitigation tool against supply disruptions and dampen increases in consumer energy costs.

Because these external welfare benefits will not necessarily be captured by a private-sector investor who relies on arbitrage, such an investor may have a reduced incentive to invest in energy storage due to the diminished value of arbitrage. This raises questions regarding the best ownership structure for large amounts of storage, because it will impact both investment and operational decisions. In contrast to the decreasing benefits seen by a private owner, a transmission owner or regulated entity may have better incentives to invest in energy storage due to its valuing the external social benefits. A transmission owner, for example, may also benefit from decreased congestion costs and benefits associated with better use of infrastructure assets.[24] As a result, a regulated storage owner may view load shifting—and its many attributes beyond arbitrage—as a benefit to society, while this may not be the case for a merchant operator.[25]

In summary, the recent increases in the price of natural gas suggest a growing potential role for storage in some electric power systems. However, any analysis of energy storage that considers only one or a few attributes (such as energy arbitrage) and neglects the interplay among various sources of value is likely to significantly underestimate the value and social benefits of energy storage. The ability to realize the inherent value of storage will vary markedly with ownership, contract, and market structure. All of these factors need to be considered with cost and other potential alternatives when making any real investment decision.

Appendix A. Supplementary data

Supplementary data associated with this article can be found, in the online version, at doi:10.1016/j.eneco.2008.10.005

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[23] As an example, Felder and Newell (2007) recognize the difficulties that arise in using historical capacity market prices to estimate the value of capacity payments, due to market structure problems. Instead, they use the levelized cost of new entry, which they estimate at $58/kW-year, as a proxy value.

[24] Some of these ideas are explored in Jenkin and Weiss (2005).

[25] The question of ownership is more complicated than covered here. For example, many of the issues facing a merchant storage operator might be mitigated if, for example, the merchant owner is compensated for the benefits associated with load shifting, such as congestion relief. At the same time some real benefits associated with storage, such as better system utilization, may be difficult to quantify or specify in a contract.