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Update on the Cost of Nuclear Power

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We update the cost of nuclear power as calculated in the MIT (2003) Future of Nuclear Power study. Our main focus is on the changing cost of construction of new plants. The MIT (2003) study provided useful data on the cost of then recent builds in Japan and the Republic of Korea. We provide similar data on later builds in Japan and the Republic of Korea as well as a careful analysis of the forecasted costs on some recently proposed plants in the US. Using the updated cost of construction, we calculate a levelized cost of electricity from nuclear power. We also update the cost of electricity from coal- and gas-fired power plants and compare the levelized costs of nuclear, coal and gas. The results show that the cost of constructing a nuclear plant have approximately doubled. The cost of constructing coal-fired plants has also increased, although perhaps just as importantly, the cost of the coal itself spiked dramatically, too. Capital costs are a much smaller fraction of the cost of electricity from gas, so it is the recent spike in the price of natural gas that have contributed to the increased cost of electricity. These results document changing prices leading up to the current economic and financial crisis, and do not incorporate how this crisis may be currently affecting prices.

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INTRODUCTION

One of the contributions in the MIT (2003) Future of Nuclear Power study was an estimate of the levelized cost of electricity generated using a new nuclear power plant, and a comparison against the levelized cost from new coal or gas plants. For nuclear power, the cost of constructing a new plant accounts for the major portion of this levelized cost, and so estimating the overnight cost of construction is key. Since no nuclear plants had recently been built in the US, the MIT (2003) study provided useful data on the cost of recent builds in Japan and the Republic of Korea. This paper updates the calculations in the MIT (2003) study, primarily by adding further data on more recent builds in Japan and Korea, and by a careful analysis of the forecasted costs on some recently proposed plants in the US. We place this data in the context of the recent cost escalations for many commodities and engineering projects, and compare the levelized cost for nuclear against similar calculations for coal and gas plants.

The results show that the overnight cost of building a nuclear power plant has approximately doubled—see Table 1. Where the MIT (2003) study considered a base case overnight cost of $2,000/kW, denominated in 2002 dollars, we find a range of overnight costs around $4,000/kW, denominated in 2007 dollars. The overnight cost of building coal- and gas-fired plants has also increased, although perhaps not quite to the same extent. Where the MIT (2003) study considered a base case overnight cost for a coal-fired plant of $1,300/kW, denominated in 2002 dollars, we find a range of overnight costs centered around $2,300/kW. Where the MIT (2003) study considered a base case overnight cost for a gas-fired plant of $500/kW, denominated in 2002 dollars, we find a range of overnight costs around $850/kW. Although we calculate a 100% increase in the overnight cost for nuclear and only a 77% increase in the overnight cost for coal and 70% for gas, the large range of uncertainty around the estimates for each technology – nuclear, coal and gas – make it arguable whether there has been a relative shift in the capital costs among the alternatives.

Incorporating all cost elements, we find that the levelized cost of electricity from nuclear power is 8.4¢/kWh, denominated in 2007 dollars. The levelized cost of electricity from coal, exclusive of any carbon charge, is 6.2¢/kWh, denominated in 2007 dollars. The levelized cost of electricity from gas, exclusive of any carbon charge, is 6.5¢/kWh, denominated in 2007 dollars. In its base case, the MIT (2003) study had applied a higher cost of capital to nuclear power that it applied to either coal- or gas-fired power. The MIT (2003) study also reported results with this risk premium removed so that a comparable cost of capital was applied to both nuclear and coal-fired power, and we repeat that calculation here: removing this risk premium from our calculations lowers the levelized cost of electricity from nuclear power to 6.6¢/kWh. Adding a \$25/tCO_2 charge to coal- and gas-fired power raises the levelized cost of electricity from coal to 8.3¢/kWh and the levelized cost of electricity from gas to 7.4¢/kWh. These results are summarized in Table 1 and Figure 1.

2. NUCLEAR POWER PLANT CONSTRUCTION COSTS

A Consistent Method for Quoting the Cost of Construction at Different Plants

Published estimates for the cost of constructing a new nuclear plant can vary greatly, sometimes by a factor of two or more. For example, in August 2007, the Reuters news service reported that two 1,350 MW reactors to be built for the company NRG at its

South Texas site would cost between $6 and $7 billion. That translates to between $2,200 and $2,600/kW of capacity. In January 2008, the St. Petersburg Times newspaper reported that two 1,100 MW reactors being planned for Florida Power & Light (FPL) would cost between $12 and $18 billion. That translates to between $5,500 and $8,200/kW of capacity. Based only on these reported figures, it would appear as if the nuclear units planned for Florida were forecasted to cost as much as three times the units planned for Texas! However, this would be an erroneous conclusion. The Texas figure only covers the price NRG would pay to Toshiba for the plant, i.e., it is the price of the engineering, procurement and construction (EPC) contract. It excludes a large number of other costs that NRG would have to cover in order to complete the plant – so called owner's costs. The Florida figure not only includes these owner's costs, but also includes expenditures on transmission system upgrades unrelated to the specific plant being built. Also, the Texas figure is an overnight cost, which is the cost of all the parts and labor required over several years of construction, but denominated in current dollars. The Florida figure includes the effect of inflation on the total dollars spent over the projected construction period. Finally, the Florida figure includes charges made to cover the utility's cost of capital during the period of construction – financing costs – while the Texas figure does not.

Each of the Texas and Florida figures reflects a traditional method for quoting the cost of a nuclear plant, but the quotation methods are so different that a raw comparison of the two figures against one another is worse than useless. When working with publicly reported figures, it is essential to exercise great care to put the figures on the same terms. In fact, as we shall see below, the actual cost estimates for the Texas and Florida nuclear plants do not differ very significantly at all once appropriate care is given to make the figures comparable.

In order to clarify the problem and to help explain some steps that are necessary in order to make differently quoted cost estimates comparable, we have constructed the illustrative example shown in Table 2. The illustration provides cost data on the construction of a hypothetical nuclear power plant, and lays out a few standard, but very different methods for quoting these same costs. The illustration gives a measure of how large a disparity one can expect for the different methods, even when the underlying plant and cost data are the same.

For the hypothetical nuclear plant, construction is planned to occur over a five year period running from 2009 through 2013, so that the plant is ready to begin production at the end of 2013 and the start of 2014. The future owner and operator of the plant orders it from a vendor who will construct the reactor and power generation unit under an EPC contract. Lines [3] and [4] show how the cost is typically quoted by the vendor. The vendor’s total EPC overnight cost quoted in 2007 dollars is $3,333/kW. Assuming that the nuclear plant’s capacity is 1,000 MW, this translates to $3.333 billion. These figures represent the cost of the relevant parts and services were those services to be provided immediately once the EPC contract negotiations are completed, i.e., overnight. In fact, these parts and services will be delivered according to a construction schedule which is shown in Line [3]: 10% of these parts and services will be provided in 2009, 25% in 2010, 31% in 2011, and so on. Line [4] shows the corresponding dollar figures apportioned across these years, but still quoted in 2007 dollars.

Lines [5]-[11] show how the cost for the same plant is typically quoted by a regulated utility as it submits filings seeking approval for the plant. Line [5] is the vendor's EPC cost, but these figures have been adjusted for inflation so that each year's figure reflects the expected nominal expenditure in that year. Line [6] shows the owner's costs, i.e., costs that the utility will have to cover out of its own pocket, in addition to the vendor EPC costs. The figures shown in line [6] are 20% of the figures shown in line [5]. A 20% figure is a reasonable assumption absent specific information for a given plant. Line [7] shows the cost of transmission system upgrades which are scheduled in concert with the construction of the new generation capacity. There is no standard ratio for this item, as it depends significantly on the specific situation within each transmission territory including the regulatory rules in operation, so the figures shown are simply given. Line [8] shows the total of lines [5], [6] and [7]. This total cost, which is exclusive of financing costs, is $4,706/kW. The regulated utility will be allowed to recover this total cost through customer charges. It will also be allowed to recover capital costs or financing charges. These are calculated in line [9], assuming an effective capital charge of 11.5%.[1] Line [10] shows the total costs as expended, inclusive of this capital charge. Line [11] cumulates this total cost, which is a step in calculating the allowed annual capital charge. By the end of 2013, when the plant is complete and ready to start producing power, this total cost, inclusive of capital charges, is $5,837/kW. This is 75% more than the vendor's EPC overnight cost of $3,333/kW, although the difference

[1] What capital or financing charges are recoverable depends entirely on the regulatory rules in place. Financing charges are often denoted using specialized terminology unique to the particular regulatory rules applicable to the particular plant. A common terminology in the U.S. is AFUDC which stands for Allowance for Funds Used During Construction. Different regulatory procedures allow different calculations of what financing charges may be included, so there are multiple ways of calculating line [9], and our hypothetical illustration is just meant to capture the general idea. This same proviso applies to how non-regulated firms record the cost of a plant in their financial statements, although in this case it is accounting standards that govern the calculation.

between the two estimates is purely a question of the method of quotation, i.e., of what is in and what is out and how the dollar expenditures are denominated, whether in 2007 dollars or dollars as expended.

We have boxed a number of the figures shown in the table: line [4F], line [8F], line [10F] and line [14F]. The first three figures reflect the quotation methods most often encountered in published reports. Line [4F] is the total vendor EPC overnight cost quoted in 2007 dollars, and it is the lowest of all the figures. Lines [8F] and [10F] are two alternative figures often reported in utility filings. Both are total costs, inclusive of owner's costs and of transmission costs. The former excludes financing costs and the latter includes them.

Line [14F] represents the standard basis for quoting comparable costs across different plants as described in the MIT (2003) Future of Nuclear Power study. It reflects the "busbar" cost, including only transmission costs related to connecting the plant to the grid, and excluding the costs of expanding the overall transmission network to handle the growing power needs which are independent of the specific plant generating the power. Therefore it excludes the costs from line [7] in our illustration. It is inclusive of owner's costs – line [6] in our illustration. Therefore, we take line [5] + [6] = [8]. Unfortunately, it makes little sense to add up the different annual expenditures in line [8] since these are denominated in dollars for different years, incorporating different amounts of inflation. Therefore, the industry convention is to quote the total expenditures as an "overnight cost" using a single year as the baseline. Lines [14] and [15] show this overnight cost quoted in \$2007 figures, when the plant is being contemplated, and in \$2013 figures, when the plant is scheduled to be completed and ready to start producing power. The terminology and calculations shown in lines [12]-[15] are those used in the MIT (2003) Future of Nuclear Power study Appendix 5, Table A-5.A.2, although the costs have been adjusted upward.

In the hypothetical example shown in Table 2, our overnight cost figure is 20% more than the overnight cost reflecting only vendor EPC costs, 15% less than the utility's total cost as reported in regulatory filings, exclusive of financing charges, and 31% less than the utility's total cost as reported in regulatory filings, inclusive of financing charges. These results help benchmark reported figures that do not provide a complete breakdown of all elements, but which do describe the quotation method. With this analysis of methodology in hand, we are ready to turn to an analysis of new information about the cost of constructing a nuclear power plant.

Recent Japanese and Korea Builds: 2004-2006

The MIT (2003) Future of Nuclear Power study provided useful data on the cost of recent builds of 7 reactor units in Japan and the Republic of Korea completed between 1994 and 2002. Translated into US figures, the costs of these units ranged from \$1,790/kW to \$2,818/kW. Table 3A shows these figures in column [H]. The overnight cost would be slightly lower, excluding as it does the effect of inflation, and this adjustment is made in columns [I] and [J]. This yields a range of overnight costs between \$1,611/kW and \$2,536/kW in 2002 dollars. Of course, for this data to be meaningful today, one needs to escalate these figures to 2007 dollars. For this calculation, we apply a 15% per annum nuclear power capital cost inflation factor to put these figures into 2007 dollars. We discuss the choice of this escalation factor below. Therefore, these costs would range from $3,222/kW to $5,072/kW expressed in 2007 dollars. The average is $4,000/kW, expressed in 2007 dollars.

Since the publication of the MIT (2003) study, over the years 2004-2006, five additional units have been completed in Japan and Korea. Table 3B reports the cost figures for these later builds. Column [F] shows the costs as reported by the respective plant owners in press releases and company annual reports. The Japanese figures are reported in Yen and the Korean figures in Won. Consistent with the MIT (2003) study, in columns [G] and [H] we convert these to US dollar figures applying a purchasing power parity (PPP) conversion factor corresponding to the country and year in which the plant went into commercial operation. The costs shown in column [H] are totaled as expended, and so reflect inflation through time. To arrive at an overnight cost, we apply an adjustment factor as shown in column [I], yielding overnight costs shown in column [J]. These costs are denominated in the various years in which each plant was completed, and so we apply the 15% inflation rate, as shown in column [K], to arrive at an overnight cost denominated in 2007 dollars, as shown in column [L]. The overnight costs on these units range between $2,357/kW and $3,357/kW, expressed in 2007 dollars. The average is just under $3,000/kW, expressed in 2007 dollars. This more recent range is lower than the range for the earlier Japanese and Korean builds, perhaps reflecting continuing improvements in construction or other design factors.

Other Builds Outside the US

Besides these 5 Japanese and Korean units, several other plants have recently been constructed in the world.

Some of these plants have been built in China. An important caution must be applied, however, in considering whether to use construction costs in a country like China that is at a very different level of development as an indication of the possible cost of construction in a country such as the US. Even extrapolating construction costs from Japan and Korea to the US context is fraught with dangers. The use of purchasing power parity conversion ratios is one attempt to cope with these dangers, but a highly imperfect one.[2] Extrapolation from a country such as China, is likely to lead to erroneous conclusions unless great care is given to adjust the figures accordingly. We are not sure whether the results would be worth the effort and be broadly accepted by others. In any case, the task is beyond the aspirations of this paper.

A new plant is still under construction at Olkiluoto in Finland. It is to be the first using Areva's EPR design. The original estimate for the cost was €3.2 billion ($4.5 billion) with a completion date in 2009. This translates to $2,800/kW, which is low when compared to the earlier set of Japanese and Korean builds, but in the range of the more recent Japanese and Korean builds. This is surprising, since one would normally expect the figure to incorporate interest costs and therefore need to be reduced somewhat. However, there is no detail on what is included in this figure, and so it must be handled carefully. In any case, the reactor is now far behind schedule and over budget. The construction schedule has been lengthened to 7 years with a revised completion date of 2012. The revised cost estimate is €4.5 billion ($6.3 billion), which raises the calculated overnight cost to just under $4,000/kW, raw, i.e., without appropriate adjustments for what may have been included or excluded. The delay and cost overruns serve as a

[2] Had we used market exchange rates, the Japanese construction costs would have been much higher and the Korean construction costs much lower.

reminder that some of the other forecasted cost numbers discussed in this paper are optimistic when averaged together with troublesome builds such as this one.

A second EPR is under construction at Flamanville in France, to be operated by EDF. It is to have a capacity of 1,650 MW. Construction began in December 2007 and was scheduled to take 54 months with commercial operation beginning in 2012. Construction and engineering costs, exclusive of owner's costs, were originally forecasted to be €3.3 billion ($4.8 billion) according to EDF. Construction has run into some problems that seem similar to the situation at the Olkiluoto site, but EDF claims it will still be able to meet the 2012 in service target date. The cost estimate has since risen to €4.0 billion, including an adjustment from 2005 € to 2008 €.

Planned Plants in the US

Although no new plants have been built in the US in recent years, several have been proposed. In a couple of instances, detailed estimates have been submitted to state regulatory authorities. In other instances, only summary numbers have been reported, whether in official filings or in press statements. It bears repeating, however, that none of the figures reported for these plants represent actual costs. No concrete has been poured. These are all estimates of what it would cost if construction were to begin. They are not evidence of actual costs as executed. Nevertheless, each of these represents a serious effort to project the costs under the then current situation, and so long as they are taken with an appropriate measure of salt, they provide some useful insights.

The figures for each plant are presented in Table 4. In the paragraphs that follow, we discuss each plant, the source data and how we produced our standardized overnight cost estimate.

The first entry is TVA's cost estimate for construction of an ABWR unit at its Bellefonte site. This estimate was made in 2005 in cooperation with the DOE, Toshiba, GE, Bechtel and others to help advance the general public discussion about new nuclear builds. The estimate was not produced in connection with the actual, imminent construction of a new unit at Bellefonte.[3] The design examined is similar to the design used for a number of the Japanese plants shown in Tables 3A and 3B: the Kashiwazaki Kariwa Unit 6 built for Tokyo Electric Power Corporation (TEPCO), the Hamaoka Unit 5 built for Chubu Electric, and the Shika Unit 2 built for Hokuriku Electric. The cost estimate was published by Tennessee Valley Authority (2005). The published figure of \$1,611/kW, however, is for EPC overnight costs only, and does not include owners' cost. Therefore, we add 20% to the reported figure in order to produce a full overnight cost of \$1,933/kW as reported in 2004 dollars. Escalated to 2007 dollars using our 15% rate, the overnight cost is \$2,930/kW.

The second entry is FPL's cost estimate for construction of two ESBWR units at its Turkey Point site on Biscayne Bay south of Miami. This estimate was made in FPL's petition with the Florida Public Service Commission in October 2007 asking for a determination of need for the units. Construction of the units could begin as early as 2013, with generation starting in 2018 at the earliest for the first unit and 2020 for the

[3] However, in October 2007, TVA did submit an application for a Combined Operating License to the Nuclear Regulatory Commission for two new AP1000 units at Bellefonte, units 3 & 4.

second. FPL's application included two alternative designs: the GE ESBWR with a 1,520 MW capacity for each unit, and the Westinghouse AP1000 with a 1,100 MW capacity for each unit. FPL constructed its cost estimate relying heavily on the estimate produced by TVA for its Bellefonte site using GE's ABWR design. FPL claims that the unit cost estimate from the TVA study is nevertheless informative for both the ESBWR and the AP1000 designs it was considering. The cost estimate included adjustments from the TVA Bellefonte study made to fit the specifics of the FPL proposal and to account for inflation since the TVA estimate was made. The widely cited figure from this filing of $3,800/kW in 2007 dollars includes the cost of transmission upgrades to FPL's regional network. And the widely cited total project figure of $12.1 to $17.8 billion includes capital charges. However, the filings give us sufficient information to back out these components and arrive at a full overnight cost of $3,530/kW in 2007 dollars. The corresponding full project overnight cost would be $10.7 billion for the two units.

The third entry is Progress Energy's cost estimate for construction of two AP1000 units at a new site in Levy County, Florida on the Gulf of Mexico just south of the panhandle. This estimate was also made in a petition for determination of need filed with the Florida Public Service Commission. Progress Energy filed the petition in March 2008 looking to generation starting in 2016 for the first unit and 2017 for the second. Excluding capital and other charges, the total project cost is $9.304 billion for both units expressed in 2007 dollars. This translates to $4,206/kW in 2007 dollars. Progress Energy (2009) recently announced that it had successfully signed an EPC contract with Westinghouse and Shaw for $7.65 billion. The figures in this recent press release appear to match those in the petition filed last year.

The fourth entry is South Carolina Electric & Gas Company's (SCE&G) cost estimate for construction of two AP1000 units at the V.C. Summer Nuclear Station site near Jenkinsville, South Carolina. SCE&G's partner in the project would be Santee-Cooper, with the respective shares being 55% and 45%. The total capacity of the two units is expected to be 2,234 MW. The cost estimate was made in a combined environmental application and petition for a determination of need filed by SCE&G with the Public Service Commission of South Carolina in May 2008. Costs were projected based on construction beginning soon and looking to generation starting in 2016 for the first unit and 2019 for the second. Total project costs of $6.313 billion for SCE&G's 55% share have been reported. This translates to a total project cost of $11.479 billion. However, once again this includes transmission upgrades and capital charges. Other reports have given a $9.8 billion total that excludes the transmission upgrades and capital charges, but this sums together expenditures made in different years including inflation projected over the various horizons. We use the detailed filing to exclude capital and other charges and to denominate the costs in 2007 dollars. We calculate a total project cost of $8.459 billion for both units expressed in 2007 dollars. This translates to $3,787/kW in 2007 dollars.

The fifth entry is Georgia Power's cost estimate for construction of two AP1000 units at its Plant Vogtle site in Burke County, Georgia. These would be Units 3 & 4 at the site. Georgia Power is a subsidiary of Southern Company. The total capacity of 2,200 MW would be shared with Oglethorpe, MEAG and Dalton Utilities, with the shares being 45.7% for Georgia Power and 30%, 22.7% and 1.6%, respectively, for each of the other owners. Georgia Power's cost estimate was produced in its application for certification of the units and its updated integrated resource plan, filed with the Georgia Public Service Commission in August 2008. The two units are proposed to come on-line in 2016 and 2017. The total in service cost is forecasted to be $6.447 billion for Georgia Power's share, or $14.107 billion in total and $6,412/kW. Unfortunately, all detailed information about this cost figure is redacted in Georgia Power's filing, and so it is impossible to exclude transmission and capital charges and also impossible to put the figure into constant 2007 dollars using Georgia Power's assumption. However, if we assume that these components are the same proportion of Georgia Power's filings as they are for SCE&G, then the total project cost should be reduced to 74% of the reported figure, i.e., to an overnight cost of $10.439 billion or $4,745/kW in 2007 dollars. This leaves the Vogtle units with the highest forecasted overnight cost of the four newly planned sets.

The sixth entry is NRG's cost estimate for the two new units at its South Texas Project, units 3 & 4. The units would be GE's ABWR design with a combined capacity of 2,660 MW. The projected construction schedule is six years for the pair. The existing South Texas Project units are co-owned with CPS Energy, San Antonio's municipal power authority, and with Austin Energy, the municipal authority for the city of Austin. In 2006, an NRG press release announced the cost for the two units at $5.2 billion, or $1,900/kW. In August 2007 Reuters reported the value of the contract between NRG and Toshiba for building the units at between $6 and $7 billion, or between $2,200 and $2,600/kW. In September 2007, NRG's CEO, David Crane, in an interview with the Wall Street Journal discussed a cost of between $2,000 and $2,250/kW. In early 2008, the City of Austin chose not to participate in the project, citing the overly optimistic cost estimate and construction schedule. In March, 2008, when NRG announced a partnership with

Toshiba for the development of new nuclear plants in the US, NRG produced a presentation by its CEO displaying its updated cost estimates for construction of the ABWR design. The EPC contract overnight cost was estimated at $2,900/kW. Owner's cost was estimated at $300/kW, approximately 10%, which is surprisingly low. Typically, owner's cost is in the neighborhood of 20%, although it can vary depending upon whether a unit is being built in a greenfield site and other factors. Transmission costs are separate and not included in NRG's figure, as are interest during construction. Adding another 10% for owner's costs, brings the total cost to $3,480/kW, the lowest among the estimates, but very close to the estimate of $3,530 for FPL's Turkey Point units.

The overnight cost of the proposed units – i.e. excluding the TVA estimate as it was not an actual build proposal and was for an earlier year – lie between $3,500 and $4,800/kW, denominated in 2007 dollars. This is still a large range. None of the values in this range represent the actual cost of plants built. All of these assume construction goes on schedule with modest allowances for contingency. They forswear delays and overruns like those that plagued the US industry in an earlier era and that are plaguing the Olkiluoto plant currently under construction in Finland. Based on this data, and in light of the experience of actual builds in Japan and Korea, for the rest of this paper we choose to use $4,000/kW in 2007 dollars as a central value for our comparisons.

Escalating Costs

One of the most important reasons for updating the overnight cost figures from the MIT (2003) study is the sharp escalation in costs experienced in the last few years, especially for major engineering projects. Between 2002 and 2007, the GDP deflator index grew by 15% in total, which averages to a little less than 3% per annum. However, the price of key commodities used in construction of a power plant grew much faster. For example, the price of fabricated structural metal increased by more than 36% over these 5 years, the price of high alloy and stainless steel castings increased by more than 46%, and the price of cement increased by more than 37%. The price of engineering services increased as well. The combined effect has been a dramatic increase in the price of building new electricity generating plants of all kinds. The consulting firm IHS-CERA index of capital costs for power plants shows an increase of 60% for non-nuclear power plant construction between 2002 and 2007 – an annual increase of 9.9% –and an increase of 276% or 22.5% per annum for nuclear power plants.

Using the MIT (2003) estimate of $2,000/kW in 2002 dollars, and a central estimate of $4,000/kW in 2007 dollars, our results suggest an annual rate of increase in overnight costs of approximately 15% during this period. This represents a sizeable premium to the general rate of inflation – the 3% per annum mentioned above for the GDP deflator.

Even as prices were climbing steeply, the difficult task was to understand what fraction of the price increases represented a new, long-lasting change, and what fraction represented the temporary pressures of rapidly escalating demand outstripping the development of new supply capacity. Since mid-2008, commodity prices have reversed themselves and moved sharply downward. The cost of engineering services has probably declined sharply as well. Much of this reversal is due to the faltering levels of economic activity in the US and worldwide. Now the question is how much of this recent decline in prices will be translated into a lastingly lower cost of new construction, and how much represents just a temporary respite from the higher level of costs that had been reached. It is impossible to predict the true impact of these developments at the time of writing this report, and we focus simply on reporting the available data on costs as generated in the last few years. The cost data we report in Table 4 would appear to represent results just at the peak of the recent escalation.

Figure 2 shows the data for the newer Japanese and Korean builds from Table 3B and the data for the planned US plants from Table 4. Also shown is the base case figure from the MIT (2003) study and an extrapolation of this figure at both a 3% rate (i.e., GDP deflator) a 15% escalation rate (actual plant cost escalation rate).

3. LEVELIZED COST OF ELECTRICITY FROM NUCLEAR POWER

Using this revised estimated overnight cost of a new nuclear reactor, we apply the methodology from the MIT (2003) study to calculate a levelized cost of electricity.[4] The assumptions made to calculate a levelized cost of electricity are displayed in Table 5. These are in general the same as those used for the Base Case of the MIT (2003) study: compare our Table 5 to the MIT (2003) study's Table A-5.A.4 "Base Case Input Parameters". Since our primary objective is to update the capital cost used in the MIT (2003) study, we do not revisit every element of the original inputs. We model a plant with a capacity of 1,000 MW, a capacity factor of 85%, and a life of 40 years. The heat rate is 10,400 Btu/kWh. Based on the results of the previous analysis, we assume that this plant has an overnight cost in 2007 dollars of $4,000. We set the incremental capital

[4] The spreadsheet model for calculating levelized costs is available at the website of the MIT Center for Energy and Environmental Policy Research: web.mit.edu/ceepr/www/workingpapers.html.

expenditures to maintain the same ratio of incremental capital cost to overnight cost as was used in the MIT (2003) study, giving us $40/kW/year. We adjust the fixed and variable O&M costs from the MIT (2003) study to reflect the 10% decline in reported O&M costs between 2002 and 2007 documented by the US Energy Information Administration (US EIA), so that our fixed O&M cost is $56/kW/year and our variable O&M cost is 0.42 mills/kWh.

We adjust the fuel cost from the MIT (2003) study to reflect most importantly a higher price for uranium – $80/kgHM – and a higher price for SWUs – $160/SWU – both measured in 2007 dollars. We also assume a price of $6/kgHM for yellow cake conversion and $250/kgHM for fabrication of uranium-oxide fuel. We assume 0.2% loss at each of the stages of conversion, enrichment and fabrication. Using the methodology described in Appendix 5 of the MIT (2003) study, we derive an optimum tails assay of 0.24%, an initial uranium feed of 9.08 kgU and a requirement of 6.99 SWUs. We assume the plant is operated at a burn-up of 50 MWd/kgHM. This yields a fuel cost of 6.97 mil/kWh or $0.67/mmBtu.

For the cost of disposal of the spent fuel waste, we follow the MIT (2003) study and use the statutory fee of 1 mill/kWh currently charged under the Nuclear Waste Policy Act of 1982. The MIT (2003) study had assumed a $350 million cost to decommission the plant at the end of its life. We adjust this to maintain the same ratio of decommissioning cost to overnight cost as was used in the MIT (2003) study, giving us the figure of $700 million, expressed in 2007 dollars. Consistent with the MIT (2003) study, we assume a 3% general inflation rate and that real non-fuel O&M costs escalate at 1% while real fuel costs escalate at 0.5%. The tax rate assumed is 37%.

To be consistent with the MIT (2003) study, we calculate present values using a 50/50 debt/equity ratio, an 8% cost of debt, and a 15% cost of equity. These imply a 10% weighted average cost of capital (WACC) which should be applied to the project's unlevered after-tax cash flows to yield the net present value.[5] It is important to understand that these costs of capital are meant to reflect a "merchant model" in which the nuclear plant delivers power into a competitive wholesale market without any assured rate of return. A nuclear plant built by a regulated utility, with the construction costs approved and passed along to customers with greater certainty could probably be financed at a lower cost of capital. This would reflect the fact that some of the construction, completion, operating and price risks are being shared between the shareholders in the regulated utility and the customers of the regulated utility. The total risks are the same, but in the merchant model the shareholders bear all of the risk. Our calculation also does not include any of the benefits from the production tax credits or loan guarantees provided to the first new builds under the Energy Policy Act of 2005.

The MIT (2003) study applied a lower capital cost to evaluate coal-fired and gas-fired generation, assuming a 60/40 debt/equity ratio, an 8% cost of debt, and a 12% cost of equity, implying a 7.8% weighted average cost of capital (WACC). As a variation on its base case, the MIT (2003) study evaluated the cost of nuclear applying to nuclear this

[5] There is one important difference between our calculations and those of the MIT (2003) study relating to how the cost of capital is employed. The MIT (2003) study applied the cost of debt to the debt cash flows and the cost of equity to equity cash flows. The debt and equity cash flows were calculated assuming a given amortization schedule over the life of the project. Unfortunately, this means that a constant cost of equity capital was applied despite a changing debt-to-equity ratio and therefore a changing level of risk in the debt. Implicitly, this implied an increasing risk premium applied through time for the total nuclear cash flows. This raised the levelized cost of electricity, and accounts for a significant portion of the discrepancy between the levelized cost of electricity calculated in the MIT (2003) study and the cost calculated in other studies—see Osouf (2007). In our calculations, the WACC is applied directly to the unlevered after-tax cash flows, so that the risk premium is effectively held constant through the life of the project. Were all of the inputs held constant, this change in methodology would lower the calculated levelized cost of electricity.

lower cost of capital, and we do so as well here. Also consistent with the MIT (2003) study, we assume the 5-year construction schedule and the 15-year MACRS depreciation schedule as shown in Table 5.

Table 6A shows how these assumptions generate the time profile of itemized pre-tax cost cash flows, as well as depreciation, over the full life of the plant. These values are nominal in the years expended, so that they incorporate the different escalation factors. Table 6B shows the after-tax cash flows. We have summed the cost of construction together with the associated depreciation tax shield. We have summed the incremental capital cost together with the decommissioning cost, and we have calculated the after-tax cost for these items as if they were immediately expensed – i.e., without fully accounting for the time profile of the associated depreciation tax shields. We have summed the cost of fuel together with the waste fee, i.e., the cost of disposing of the fuel, producing a full fuel cycle charge. The final column displays the total of these various after-tax costs. Table 6C shows the present value of each of these after-tax cost items. Consistent with the MIT (2003) study, we have made the year of completion, 2013, date 0 and all present value calculations are made accordingly so that net present values are measured to 2013. It is a trivial matter to recalculate them to 2007 as is done at the bottom of the table for the convenience of the reader. The present value of the total costs is $6,381 million. The 2013 present value of the overnight construction cost net of depreciation tax shields equal $4,603 million, or 72% of the total cost. Adding in the incremental capital cost over the life of the plant, plus the decommissioning cost makes the total after-tax capital cost $5,051 million, or 79% of the total after-tax cost. Non-fuel operating and maintenance costs total $699 million, or just 11% of the total cost. Fuel costs, inclusive of the waste disposal charge, total $631 million, or just 10% of the total cost.

Table 6D calculates the levelized cost of electricity from nuclear power. Setting a price of 8.4¢/kWh in 2007 dollars, column [D] shows the price through time, column [E] shows the after-tax revenue from the sale of electricity expressed in nominal dollars as earned. Column [F] calculates the present value of this revenue. Column [G] shows the present value of the total costs, taken from Table 6C, and column [H] shows the present value of the net cash flow. A price of 8.4¢/kWh yields a present value of after-tax revenues equal to the present value of after-tax costs, and so 8.4¢/kWh is the levelized cost of electricity from nuclear power measured in 2007 dollars. Applying the percentages derived at the bottom of Table 6C, we have that capital costs account for 79% of this levelized cost of electricity, or 6.6¢/kWh, non-fuel O&M costs account for 11%, or 0.9¢/kWh, and fuel costs, inclusive of waste disposal, account for 10%, or 0.8¢/kWh.

As mentioned earlier, we consider a variation on the cost of capital for nuclear, setting the inputs for the cost of capital equal to those for coal. Using this lower cost of capital and repeating the steps shown in Tables 6A-6D lowers the levelized cost of electricity by approximately 1.7¢/kWh, bringing the total cost of nuclear power down to 6.6¢/kWh (¢/kWh figures do not sum due to rounding).

4. COMPARISON TO COAL- AND GAS-FIRED GENERATION COSTS

While the focus of this study is an update of the cost of building nuclear power plants, it is important to see the escalation in the cost of nuclear plants in comparison with the escalation in the cost of other power plants. The MIT (2003) study compared the levelized cost of electricity from nuclear plants against the levelized cost of electricity from pulverized coal plants and from combined cycle gas turbine plants. In this section we develop the revised estimates for the constructing coal- and gas-fired plants, and we calculate the corresponding levelized cost of electricity.

Updated Coal Plant Costs

The MIT (2003) Future of Nuclear Power study estimated a $1,300/kW capital cost, denominated in 2002 dollars, for a 1,000 MW pulverized coal burning power plant. The MIT (2007) Future of Coal study evaluated a broader set of coal-fired designs, including sub-critical pulverized coal, supercritical and ultra-supercritical pulverized coal, as well as circulating fluid-bed, with capital costs ranging from $1,280/kW to $1,360/kW, denominated in 2005 dollars. How have capital costs changed since then? To answer this question, we look to a small sample of proposed plants for which it was possible to obtain a minimal amount of detail on what was included in the cost estimate and in which year's dollars it was denominated. We limit our focus to super- and ultra-supercritical pulverized coal plants. Table 7 shows our estimate of the standardized overnight cost at each plant, denominated in 2007 dollars. In the paragraphs that follow, we discuss each plant, the source data and how we produced our standardized overnight cost estimate.

The reported cost of constructing a coal-fired power plant can suffer from the same ambiguity that we earlier identified for the reported cost of nuclear power plants. Because the construction time for a coal-fired plant is typically shorter than for a nuclear power plant, the impact of inflation and of financing costs results in a smaller discrepancy between some of the quotation methods, but otherwise the problems are the same. Assuming a four-year construction schedule, our overnight cost figure for a coal-fired plant is 20% more than the overnight cost reflecting only vendor costs, 14% less than the utility's total cost as reported in regulatory filings, exclusive of financing charges, and 27% less than the utility's total cost as reported in regulatory filings, inclusive of financing charges.

Shortly before FPL filed for approval of its Turkey Point nuclear units, it had proposed a pair of ultra-supercritical pulverized coal plants to be built at a new Glades Power Park. Although the Florida Public Service Commission ultimately rejected the proposed plant, the cost estimate made is, nevertheless a useful indicator of what the plant was believed to cost at the time the estimate was made. And the fact that FPL's Glades coal plant estimate and its Turkey Point nuclear plant estimate were made at approximately the same time and by the same company gives the coal plant estimate added interest. FPL's Determination of Need filing for the coal units was made in February 2007. Each unit would have a capacity of 980 MW. The units were to be designed to burn bituminous coal, although up to 20% of the fuel supplied could be petroleum coke. The first unit was to be constructed over a 52 month schedule ending with commercial operation in June 2013. As with the Turkey Point nuclear units, the total estimated cost of $5.7 billion includes major transmission network upgrades and financing costs, and the figure is denominated in a combination of 2013 and 2014 dollars. We back out one-half the transmission costs and all of the financing costs, which yields a total cost as expended of $4.424 billion. Backing out the effect of the 3% estimated inflation yields an overnight cost denominated in 2007 of $3,804 billion, or $1,941/kW.

In May 2005, Duke Power announced its intention to build one or two supercritical pulverized coal units of 800 MW capacity each at its Cliffside station in North Carolina. The units were planned for bituminous coal. Construction on the first unit was originally tentatively projected to begin September 2006 with commercial operation starting as soon as 2010, although in updated filings Duke estimated a construction schedule for the first unit of approximately 50 months. Duke Power's original press release estimated the total cost at $2 billion. Ultimately, only one unit was approved and, according to Duke's latest filing in February 2008, the cost for the single unit had climbed to $1.8 billion, exclusive of $550-600 million in financing charges. This figure, too, needs to be adjusted to convert it to an overnight cost denominated in 2007 dollars by backing out inflation, which yields us an estimated overnight cost of $1.548 billion, or $1,935/kW. Construction on this unit began early in 2008.

In October 2005, American Municipal Power-Ohio (AMP-Ohio) had first announced plans to build a new pulverized coal project in Meigs County, Ohio. AMP-Ohio is a non-profit corporation organized to own and operate electric power plants and other facilities on behalf of its members which are public power entities in Ohio, Pennsylvania, Michigan, Virginia, West Virginia and Kentucky. The project is actually composed of two 480 MW units – i.e., a total capacity of 960 MW – operating at an annual capacity factor of 85%. The units are designed to burn a blend of bituminous and sub-bituminous coals. In May 2007, it submitted a detailed application for a certification of need to build the combined plant, including an estimated cost of $2.3 billion. This figure was inclusive of owner's costs and transmission upgrades, but exclusive of financing costs. Financing costs would add an additional $400 million or 17% to the costs. Subsequently, the construction schedule and cost figures were significantly revised. In January 2008, its contractor, R.W. Beck, produced a Project Feasibility Study Update which revised the cost to $2.95 billion. In October 2008, the contractor produced a new Update with a revised construction schedule and cost estimate: the total cost is now estimated at $3.257 billion, exclusive of financing costs. The financing costs are estimated at an additional $683 million or 21% of the costs. This most recent estimate assumes construction begins in October 2009 and the first unit begins commercial operation in March 2014, 54 months later, while the second unit begins commercial operation in September 2014. The estimate is for a supercritical boiler. Although the plant will have the capability to handle both bituminous and sub-bituminous (Powder River Basin) coals, the plant is being optimized for bituminous coals and the cost estimate reflects this. This cost estimate appears to be a total of dollars denominated in the years actually expended, reflecting a forecasted 2.3% inflation rate. A comparable overnight cost denominated in 2007 dollars needs to back out the effect of this inflation in the total cost reported. Also, this cost estimate includes an unknown quantity of transmission system upgrades, some of which are arguably unrelated to the busbar cost. Unfortunately, the actual amount of transmission system costs is not itemized, and it is impossible to determine what fraction should be backed out of the figure. Therefore, we arrive at an estimated total overnight cost in 2007 dollars of $2.866 billion, or $2,986/kW. This is probably a high estimate due to the unknown extra transmission related costs included.

The Southwestern Electric Power Company (SWEPCO) is a unit of American Electric Power Company (AEP) operating in Louisiana, Arkansas and Texas. In late

2006, the company announced its plan to build a 600 MW ultra-supercritical pulverized coal plant in Hempstead County, Arkansas. It would burn Powder River Basin coal, i.e., sub-bituminous. Construction time is estimated at 48 months. The estimated cost of the plant was originally $1.343 billion, although the estimate has since risen to $1.558 billion. These estimates exclude financing charges and include only those transmission expenses necessary for connection. However the dollars summed are denominated in the years expended, and so require an adjustment to be expressed in 2007 dollars. Assuming a 2.3% inflation rate gives us an estimated overnight cost expressed in 2007 dollars of $1.371 billion, or $2,285/kW. The plant has received approvals from the three state utilities commissions, as well as the environmental permits it requires, and SWEPCO is moving forward targeting commercial operation in 2012.

Across the four plants, the overnight cost estimates range from just under $2,000/kW to just over $3,000/kW. This is a large range. As a central value for our comparisons, we choose to use $2,300/kW in 2007 dollars. Compared to the MIT (2003) figure of $1,300/kW in 2002 dollars, this represents an annual inflation rate of 12% in the capital cost for a coal-fired power plant – slightly less than the 15% rate for nuclear capital costs. Figure 3 shows the original MIT (2003) estimate together with an escalation at the 3% per annum that matches the GDP deflator and an escalation at the 15% per annum corresponding to the escalation of nuclear costs. Of the four plants, only one had a cost higher than implied by this 15% escalation. The others lie below this level, but clearly above the cost implied by escalation at the GDP deflator. Even the lowest of our four plant costs is higher than the figure given by the EIA for the overnight cost of a "Scrubbed Coal New" plant, which for 2007 is $1,534/kW in 2006 dollars. Assuming an increase of 12% to bring it to 2007 dollars, the EIA figure would be $1,719/kW. However, our central estimate is very close to the EPRI (2008) figure of $2,450/kW for a conventional supercritical pulverized coal plant.

Updated Cost of Coal

The MIT (2003) Future of Nuclear Power had assumed a $1.20/mmBtu price for coal delivered to the plant, measured in 2002 dollars. Assuming 12,500 Btu coal (e.g., Central Appalachian coal), this translates to $30/short ton. Since 2002, the price of coal has escalated tremendously. Figure 4 shows a graph of the spot price of coal from 1984 through year-end 2008. Between 2002 and 2007, the average annual spot price increased by 59% in total or nearly 10% per annum. The price of coal delivered to electric utilities showed a slightly smaller rise of 46%. This smaller increase probably reflects the fact that much of the coal is delivered under contracts which delay the impact of sharp prices rises, meaning that the full impact of rising fuel cost is yet to be seen in the delivered price data. It may also reflect the fact that the portion of the delivered price attributable to transportation costs did not increase as much. It may also reflect the different rates of price increases for different types of coal that are averaged together in producing this delivered price statistic. In 2008, the average spot price of coal nearly doubled again, exhibiting the same spike and collapse that occurred in the oil, natural gas and other commodity markets.

Clearly the future price of coal is highly uncertain. Global economic growth and competition for supplies probably contributed to the secular run-up in prices over the last few years. The current recession has caused prices to collapse, probably below their long-run level. Reasonable people will differ on their forecast of the future price, although there should be a consensus that the confidence bounds on the forecast should be large. As is often done with natural gas, it is probably wise to analyze how the levelized cost of electricity varies over a broad range of possible future coal prices. As our central estimate for the price of coal, we use the figure of $2.60/mmBtu or $65/short ton of Central Appalachian coal delivered to the plant. This is far below the peak 2008 spot price which was above $130/short ton, but also above the current spot price which has fallen close to $50/ton. We also calculate how the levelized cost of electricity from coal varies with the price of coal.

The Levelized Cost of Electricity from Coal

The assumptions for our calculation of the levelized cost of electricity from coal are displayed in Table 5. We assume the heat rate of 8,870Btu/kW, which is the value assumed in the MIT (2007) Future of Coal study for supercritical pulverized coal plants. This value is near the low end of the range for the plants mentioned in Table 7. It is also at the low end of the EPRI (2008) range for conventional supercritical pulverized coal plants. This heat rate is lower than the 9,300Btu/kW assumed in the MIT (2003) Future of Nuclear study, and so we are recognizing some technical performance improvements associated with the evolving capital costs. We assume that incremental capital expenditures made during the life of the project will total $27/kW/year. This is the same ratio of incremental capital cost to overnight cost as was used in the MIT (2003) study. We adjusted the MIT (2003) study fixed and variable non-fuel O&M costs in the same fashion as we did earlier for the nuclear plant. According to the US EIA, coal plant O&M costs increased between 2002 and 2007 by a little less than 6%. Therefore, we applied this change to the MIT (2003) fixed O&M cost of $23/kW/yr and arrived at a figure of

$24/kW/year, and we applied this change to the MIT (2003) variable O&M cost of 3.38 mills/kWh and arrived at a figure of 3.57 mills/kWh.

To be consistent with the MIT (2003) study, we calculate present values using a 60/40 debt/equity ratio, an 8% cost of debt, and a 12% cost of equity. These imply a 7.8% weighted average cost of capital (WACC) which should be applied to the project's unlevered after-tax cash flows to yield the net present value. Also consistent with the MIT (2003) study, we assume the 4-year construction schedule shown in Table 5. We apply a twenty-year MACRS depreciation schedule.[6]

Tables 8A, 8B, 8C and 8D calculate the levelized cost of electricity from the coal-fired power plant. As shown at the bottom of Table 8C, the 2013 present value of total costs is $6,226 million. The present value of the overnight construction cost net of depreciation tax shields equal $2,446 million, or 39% of the total cost. Adding in the incremental capital cost over the life of the plant makes the total after-tax capital cost $2,804 million, or 45% of the total after-tax cost. Non-fuel operating and maintenance costs total $849 million, or 12% of the total cost. Fuel costs total $2,574 million, or 41% of the total cost.

As shown in Table 8D, these results imply a levelized cost of electricity from coal of 6.2¢/kWh, measured in 2007 dollars. Capital costs account for 45% of this, or 2.8¢/kWh, non-fuel O&M costs account for 14%, or 0.8¢/kWh, and fuel costs account for 41%, or 2.6¢/kWh.

[6] The MIT (2003) study had applied a 15-year schedule to the coal plant. Our understanding is that coal plants are typically depreciated using the longer 20-year schedule.

We also calculate the additional cost for coal-fired electricity in the event that carbon is priced. As shown in Table 5, we assume the coal used has a carbon intensity of 25.8 kg-C/mmBtu, which is identical to what was assumed in the MIT (2003) study. Given our heat rate assumption, this translates to a CO_2 intensity per unit of electricity produced of 0.839 $kgCO_2$/kWh, which is approximately equal to the figure given in the MIT (2007) Future of Coal study for a supercritical pulverized coal plant. As a benchmark we choose a carbon price of $25/$tCO_2$, denominated in 2007 dollars. This translates to a 2.1¢/kWh additional cost to coal-fired electricity, bringing the total cost from 6.2¢/kWh up to 8.3¢/kWh.

Every $1/mmBtu change in the initial fuel price translates into slightly less than a 0.98¢/kWh change in the levelized cost of electricity. This is equivalent to saying every $10/short ton change in the delivered price of coal translates into slightly less than a 0.39¢/kWh change in the levelized cost of electricity. Therefore, if we had assumed a $50/short ton cost of coal, then our total levelized cost of electricity from coal would have been 5.6¢/kWh. If we had assumed an $80/short ton cost of coal, then our total levelized cost of electricity from coal would have been 6.8¢/kWh.

Updated Gas Plant Costs

The MIT (2003) Future of Nuclear Power study estimated a $500/kW capital cost, denominated in 2002 dollars, for a 1,000 MW gas-fired combined cycle (CCGT) power plant with a heat rate of 7,200Btu/kW. Earlier, we estimated that the overnight costs for nuclear had escalated at approximately 15% between 2002 and 2007, and that the overnight costs for coal-fired power plants had escalated at approximately 12% over the same time period. These two escalation rates are approximately equal given the types of errors and uncertainties in such estimates. Were a 12% escalation rate to be applied to the cost of gas, an updated 2007 figure would equal $885/kW.

Since 2002 a number of CCGT plants have been built and a large number have recently been proposed. One might hope that the greater number of data points would make an update of the overnight cost for a gas plant a simpler exercise than for nuclear or for coal, where the data is much sparser. Unfortunately, the range of cost figures produced for these built plants and for recently proposed plants is very large. A number of difficulties arise that make it difficult to reduce the range of these figures. First, many CCGT plants are built as merchant plants, and the detailed information provided in regulatory filings is often missing. Therefore it can be difficult to scrutinize what has been included and what has been excluded from reported figures. It is also difficult to be determine how inflation is factored into the figure. Second, even where regulatory filings are made, quite often the detail provided is much less for a CCGT plant than for the larger scale nuclear and coal plants. Where the plants are purchased under relatively fixed price contracts, the price is considered confidential information and not included in the regulatory filings. Third, and perhaps most importantly, the range of designs is very wide, and significant effort must be put into making all of the estimates comparable with one another.

We reviewed the cost data for the following completed plants: Progress Energy Florida's 461MW Hines Energy Complex Unit 4, which was proposed in 2004 for an in-service date in 2007, the Caithness Energy LLC's 520MW Blythe Energy Project II in California, for which a formal cost estimate was filed in 2005 for an in-service date in 2007, Portland General Electric's 414MW Port Westward plant, which in its final form reported a cost estimate in 2005, for an in-service date of 2007, and Sierra Pacific Power's 514MW Tracy, Nevada unit, for which a formal cost estimate was filed in 2005 for an in-service date in 2008. We also reviewed filings for these proposed plants: PG&E's 660MW Colusa plant in California, for which an application was filed in 2006 for an in-service date of 2010, Reliant Energy's 656MW San Gabriel plant in California, for which an application was filed in 2007 for an in-service date in 2010, Progress Energy Carolina's 570MW Richmond plant, for which filings were made in 2008 for an in-service date in 2011, the Northern California Power Agency's 255MW Lodi plant, for which an application was filed in 2008 for an in-service date in 2012, the Competitive Power Venture's 660MW Vacaville plant in California, for which an application was filed in 2008 for an in-service date in 2013, Macquarie's 600MW Avenal Energy Project in California, for which an application was filed in 2008 for an in-service date in 2012, Sierra Pacific Power's 484MW Harry Allen plant in Nevada, for which filings were made in 2008 for an in-service date in 2012, and Florida Power & Light's 1,219 West County Energy Center Unit 3 plant, for which filings were made in 2008 for an in-service date in 2011.

As mentioned, the designs of these plants vary widely as do the estimated overnight costs. Table 9 lists each plant, with some of the important information about plant design. We calculate a raw overnight cost for each plant, escalated to 2007 dollars. We then make plant specific adjustments for identifiable components that add to the cost – such as duct firing or dry cooling – and some deductions – for example due to collocation of the new unit with existing facilities. Unfortunately, these adjustments only marginally reduce the large disparity in reported costs.

As a central estimate for our comparisons, we have chosen an updated overnight cost for a CCGT plant of $850/kW in 2007 dollars with a heat rate of 6,800. This reflects a slightly lower level of inflation than for the coal-fired power plant discussed earlier – 11% vs. 12% – and recognizes improvements in technological performance. Three of the most recently proposed plants have estimated costs above $1,000/kW: Sierra Pacific's 484MW Harry Allen plant in Nevada with an estimated overnight cost of $1,187/kW, the Northern California Power Agency's 255MW Lodi plant with an estimated overnight cost of $1,069/kW, and Progress Energy Carolina's 570MW Richmond plant with an estimated overnight cost of $1,257/kW. NV Energy's 514MW Tracy plant has an estimated cost of $999/kW. All of the other recently proposed plants have estimated costs below $1,000/kW. Our central estimate is slightly above the $800/kW figure that EPRI (2008) reports for state of the art heavy-duty combustion turbine combined cycle plants, and indeed even above their $820 figure for advanced designs. This is true despite the fact that most of the plants we surveyed would not be using the advanced designs – for example, many of them are based on the GE 7F turbines, and EPRI (2008) categorizes this as the state-of the art unit with the 7H class being the advanced. Our central estimate is almost exactly equal to the $847 figure reported by the California Energy Commission (2007) for comparably designed units. The EIA (2008) reports an overnight cost of $717/kW for a conventional combined cycle gas plant with a heat rate of 7,196Btu/kW, and an overnight cost of $706/kW for an advanced combined cycle gas plant with a heat rate of 6,752Btu/kW, although the document does not clarify the types of units incorporated under these two designations.

The Levelized Cost of Electricity from Gas

The assumptions for our calculation are displayed in Table 5. Many of the assumptions are identical to those made for the nuclear case, and we won't comment any more on these: plant capacity and capacity factor, inflation and real escalation rates, tax rate and depreciation schedule. We assume that incremental capital expenditures made during the life of the project will total $10/kW/year. This is the same ratio of incremental capital cost to overnight cost as was used in the MIT (2003) study. We adjusted the MIT (2003) study fixed and variable non-fuel O&M costs in the same fashion as we did earlier for the nuclear and coal plants. According to the US EIA, gas plant O&M costs decreased between 2002 and 2007 to 79% of their 2002 level. Therefore, we applied this change to the MIT (2003) fixed O&M cost of $16/kW/yr and arrived at a figure of $13/kW/year, and we applied this change to the MIT (2003) variable O&M cost of 0.52 mills/kWh and arrived at a figure of 0.41 mills/kWh.

The price of natural gas fluctuated between 2002 and today, largely in sync with movements in the crude oil price, but also showing its characteristic additional volatility. We updated the MIT (2003) base case from $3.50/mmBtu in 2002 dollars to $7.00/mmBtu in 2007 dollars, which is roughly consistent with what the current level of futures prices suggest. We discuss how changes in the price of natural gas change the levelized cost of electricity so that the reader can make his or her own adjustment to the reported figure according to his or her own views about the future of natural gas prices.

To be consistent with the MIT (2003) study, we calculate present values using a 60/40 debt/equity ratio, an 8% cost of debt, and a 12% cost of equity. These are the same assumptions as for coal, and they imply a 7.8% weighted average cost of capital

(WACC). Also consistent with the MIT (2003) study, we assume the 2-year construction schedule shown in Table 5. We apply a fifteen-year MACRS depreciation schedule.

Tables 10A, 10B, 10C and 10D calculate the levelized cost of electricity from the gas-fired power plant. As shown at the bottom of Table 10C, the present value of total costs at the start of commercial operations at the end of 2013 is $6,482 million. The 2013 present value of the overnight construction cost net of depreciation tax shields equal $822 million, or 13% of the total cost. Adding in the incremental capital cost over the life of the plant makes the total after-tax capital cost $960 million, or 15% of the total after-tax cost. Non-fuel operating and maintenance costs total $211 million, or 3% of the total cost. Fuel costs total $5,312 million, or 82% of the total cost.

As shown in Table 10D, these results imply a levelized cost of electricity from gas of 6.5¢/kWh, measured in 2007 dollars. Capital costs account for 15% of this, or 1.0¢/kWh, non-fuel O&M costs account for 3%, or 0.2¢/kWh, and fuel costs account for 82%, or 5.3¢/kWh.

We also calculate the additional cost for gas-fired electricity in the event that carbon is priced. As shown in Table 5, we assume the natural gas used has a carbon intensity of 14.5 kg-C/mmBtu, which is identical to what was assumed in the MIT (2003) study. Given our heat rate assumption, this translates to a CO_2 intensity per unit of electricity produced of 0.361 kgCO_2/kWh. Using our benchmark carbon price of \$25/tCO_2, denominated in 2007 dollars, this translates to a 0.9¢/kWh additional cost to gas-fired electricity, bringing the total cost from 6.5¢/kWh up to 7.4¢/kWh.

Every $1/mmBtu change in the price of natural gas translates to a 0.76¢/kWh addition to the levelized cost of electricity. So, for example, if we had assumed a price of natural gas of \$8.00/mmBtu, then the levelized cost of electricity from gas would be 7.2¢/kWh.

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Table 1: Summary of Results

		MIT (2003)					Update				
				LCOE					LCOE		
		Overnight Cost	Fuel Cost	Base Case	w/ Carbon Charge $25/tCO2	w/ same cost of capital	Overnight Cost	Fuel Cost	Base Case	w/ Carbon Charge $25/tCO2	w/ same cost of capital
		$2002/kW	$2002/mmBtu	2002¢/kWh	2002¢/kWh	2002¢/kWh	$2007/kW	$2007/mmBtu	2007¢/kWh	2007¢/kWh	2007¢/kWh
		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
[1]	Nuclear	2,000	0.47	6.7		5.5	4,000	0.67	8.4		6.6
[2]	Coal	1,300	1.20	4.3	6.4		2,300	2.60	6.2	8.3	
[3]	Gas	500	3.50	4.1	5.1		850	7.00	6.5	7.4	

Notes:

[A] MIT (2003), Table 5.3, p. 43.

[B] MIT (2003), Table 5.3, p. 43 for coal and gas; for nuclear see Appendix 5, Table A-5.A4.

[C] MIT (2003), Table 5.1, p. 42, Base Case, 40-year. "Gas (moderate)" case is reported here, which was $3.50 escalated at 1.5% real, equilvalent to $4.42 levelized real over 40 years.

[D] MIT (2003), Table 5.1, p. 42, Carbon Tax Cases, 40-year. We translate results quoted in $/tC into results in $/t CO2.

[E] MIT (2003), Table 5.1, p. 42, Reduce Nuclear Costs Cases. The table shows results step-wise for changing 3 assumptions, with the reduction of the cost of capital being the last step. We give the result for just reducing the cost of capital to be equivalent to coal and gas, without the other 2 assumptions being varied.

[F] From results of this study as discussed in the text.

[G] Input selected as discussed in the text. All fuel costs are escalated at 1.5% real through the life of the plant.

[H1] From results of this study, as calculated in Table 6D

[H2] From results of this study, as calculated in Table 8D

[H3] From results of this study, as calculated in Table 10D

[I] From results of this study as discussed in the text.

[J1] From results of this study, by recalculating Tables 6A-6D, setting the assumed debt fraction and the equity rate for nuclear to match coal and gas -- see Table 5, rows [16] and [18].

Table 2: Alternative Cost Quotation Methods for Nuclear Power Plants Illustrated with a Hypothetical Example

		[A]	[B]	[C]	[D]	[E]	[F]
[1]	Project Period (relative to start)	-4	-3	-2	-1	0	
[2]	Year	2009	2010	2011	2012	2013	Total
[3]	Construction Schedule as a Fraction of EPC Cost, $2007	10%	25%	31%	25%	10%	100%
[4]	Vendor EPC Overnight Cost, $2007	318	833	1,030	833	318	3,333
[5]	Vendor EPC Cost, Nominal Dollars as Expended @ 3% Inflation	337	911	1,160	966	380	3,753
[6]	Owner's Costs, Nominal Dollars as Expended	67	182	232	193	76	751
[7]	Transmission System Upgrades, Nominal Dollars as Expended				145	57	202
[8]	Total Cost, excl. Capital Recovery Charge, Nominal Dollars as Expended	405	1,093	1,391	1,304	513	4,706
[9]	Capital Recovery Charge @ 11.5%		47	178	358	549	1,131
[10]	Total Cost, incl. Capital Recovery Charge	405	1,139	1,569	1,662	1,062	5,837
[11]	Total Cost, incl. Capital Recovery Charge, Cumulative	405	1,544	3,113	4,775	5,837	
[12]	Total Outlay, Nominal Dollars as Expended	405	1,093	1,391	1,159	456	4,504
[13]	Total Cost (incl. capital charge), $2013	626	1,515	1,730	1,292	456	5,619
[14]	Overnight Cost, $2007	382	1,000	1,236	1,000	382	4,000
[15]	Overnight Cost, $2013	456	1,194	1,476	1,194	456	4,776

Notes:
All figures in $/kW.
Example assumes a total EPC overnight cost of $3,333, an inflation rate of 3%, a 20% factor for owner's cost and an allowed capital recovery charge of 11.5%.
Columns [A]-[E]
[3] Rate of expenditures is given.
[4] =$3,333*[3].
[5] =[4]*(1.03)^([2]-2007)
[6] =20%*[5]
[7] Transmission expenditures are given.
[8] =[5]+[6]+[7].
[9] [9B]=[11A]*11.5%, and so on.
[10] =[8]+[9]
[11] [11B]=[11A]+[8B]+[9B].
[12] =[5]+[6]
[13] =[12]*(1.115)^(2013-[2])
[14] =[12]*(1.03)^(2007-[2])
[15] =[12]*(1.03)^(2013-[2])

Table 3A: Overnight Costs for Actual Builds in Japan and Korea 1994-2002, per MIT (2003) Future of Nuclear Power Study

	Owner	Name of Plant	Design	Capacity MW	Commercial Operation Date	Total Project Cost: Domestic Currency millions	Total Project Cost: PPP Factor	Total Project Cost: US Equivalent $/kW	Overnight Cost: Overnight Cost Factor	Overnight Cost: US 2002 $/kW	Overnight Cost: Inflation Factor	Overnight Cost: US 2007 $/kW
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]
[1]	Tohoku Electric	Onagawa 3	BWR	825	2002	314	158	2,409	90%	2,168	2.00	4,336
[2]	Kyusyu Electric	Genkai 3	PWR	1,180	1994	525	158	2,818	90%	2,536	2.00	5,072
[3]	Kyusyu Electric	Genkai 4	PWR	1,180	1997	427	158	2,288	90%	2,059	2.00	4,118
[4]	TEPCO	Kashiwazaki-Kariwa 6	ABWR	1,356	1996	433	158	2,020	90%	1,818	2.00	3,636
[5]	TEPCO	Kashiwazaki-Kariwa 7	ABWR	1,356	1997	384	158	1,790	90%	1,611	2.00	3,222
[6]	KHNP	Yonggwang 5&6	PWR	2,000	2001-2002	3,988	867	2,300	78%	1,800	2.00	3,600

Notes:

Data is taken from the MIT Future of Nuclear Power study, Appendix 5.B Nuclear Power Plant Construction Costs, except adjustment to 2007 dollars, columns [K] and [L] and overnight cost factor for Japan, column [I], rows [1]-[5].

[H] =[F]*1,000,000/[D]/[G].

[I] This adjusts for the inflation embedded in total project costs which sum expenditures made in different years. See Table 2 and related discussion. Overnight cost factor for Japan is our estimate as the MIT Future of Nuclear Power study does not provide this. Overnight cost factor for Korea is implicitly provided in the MIT Future of Nuclear Study since both the total cost and the overnight cost are reported: 78%=1,800/2,300.

[J] =[H]*[I].

[K] Inflation factor is approx. 15% per annum, based on results in this paper.

[L] =[J]*[K].

Table 3B: Overnight Costs for Actual Builds in Japan and Korea 2004-2006

	Owner	Name of Plant	Design	Capacity MW	Commercial Operation Date	Total Project Cost: Domestic Currency millions	Total Project Cost: PPP Factor	Total Project Cost: US Equivalent $/kW	Overnight Cost: Overnight Cost Factor	Overnight Cost: US var. yrs. $/kW	Overnight Cost: Inflation Factor	Overnight Cost: US 2007 $/kW
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]
[7]	Chubu Electric	Hamaoka-5	ABWR	1,325	2004	360	134	2,023	90%	1,820	1.52	2,759
[8]	Tohoku Electric	Higashidori-1	BWR	1,067	2005	390	130	2,821	90%	2,539	1.32	3,351
[9]	Hokuriku Electric	Shika-2	ABWR	1,304	2006	370	124	2,280	90%	2,052	1.15	2,357
[10]	KHNP	Ulchin-5	OPR	995	2004	2,236	794	2,830	78%	2,215	1.52	3,357
[11]	KHNP	Ulchin-6	OPR	994	2005	2,234	789	2,849	78%	2,229	1.32	2,942

Notes:

[A]-[F] are assembled from corporate press releases and annual reports as described in the text.

Hamaoka 5 cost figure is taken from Chubu Electric Power website.

Higashidori 1 cost figure is from Kyodo News (2004), which was corroborated against the Tohoku Electric Annual Report for 2006, p. 41, change in account for Nuclear power plant and equipment.

Shika 2 cost figure is from Dow Jones International News (2006), which was corroborated against the Hokoriku Electric Power Company Annual Report for 2006, p. 20, change in account for Nuclear power plant and equipment.

Ulchin 5&6 figures are from press report: Power in Asia (2005). Costs are reported in aggregate for units 5&6 combined (4.47 trillion Won), and we have allocated the costs according to capacity.

[G] PPP factors are from the OECD for the respective countries and the commercial operation dates. See www.oecd.org/std/ppp.

[H] =[F]*1,000,000/[D]/[G].

[I] Overnight cost factors from Table 3A.

[J] =[H]*[I].

[K] Inflation factor is approx. 15% per annum, based on results in this paper.

[L] =[J]*[K].

Table 4: Overnight Costs for Some Proposed Nuclear Plants in the US

	Owner [A]	Name of Plant [B]	Design [C]	Capacity MW [D]	Projected Commercial Operation Date [E]	Overnight Cost in 2007 US $/kW [F]
[1]	TVA study	Bellefonte	ABWR	1,371	N/A	2,930
[2]	FPL	Turkey Point 5 & 6	ESBWR	3,040	2018-2020	3,530
[3]	Progress Energy	Levy County 1 & 2	AP1000	2,212	2016-2017	4,206
[4]	SCEG/Santee-Cooper	V.C. Summer 2 & 3	AP1000	2,234	2016-2019	3,787
[5]	Southern	Plant Vogtle 2 units	AP1000	2,200	2016-2017	4,745
[6]	NRG	South Texas 3 & 4	ABWR	2,700	2014-2015	3,480

Sources for columns [A]-[E]:

[1] Tennessee Valley Authority (2005), pp. 1-6.

[2] Florida Power & Light (2007b), p. 81, Table V.A.5.1.
FPL's proposal leaves open the option of building either 2 AP100s or 2 EBWRs. The overnight cost estimate shown for the two designs is the same. However, the estimate was constructed starting from the TVA study which used the ABWR design, and it was based on adjustments from that design to the ESBWR.

[3] Progress Energy (2008).

[4] SCE&G (2008) Exhibit F, Chart A.

[5] Georgia Power (2008), pp. 14 and 57.

[6] NRG (2008) and NRG fact sheet for South Texas Project Unit 3 & 4 Expansion.

Notes for column [F]:

[1] EPC overnight cost of $1,611denominated in 2004 dollars.
The $1,611 figure is incremented by 20% for owner's cost and for inflation @15% per year: $2,930=$1,611 * (1.2) * (1.52)

[2] The average across cases A-C, exclusive of transmission costs is
$3,530/kW. The figure is an overnight cost denominated in 2007 dollars, so no additional adjustment is made.

[3] Appendix last page, "New Nuclear Plant Modeling Information, Capital Cost Estimate for Strategist Modeling." "Unit Overnight Total Cost" shown is $9,303,579. $4,206=$9,303,579/2,212.
The figure is an overnight cost denominated in 2007 dollars, so no additional adjustment is made.

[4] Anticipated Construction Schedule shows anticipated plants costs as incurred, as well as transmission and financing charges. We take only the plant costs, which total $5,411,067 in nominal dollars inflated as expended. We back out the approx. 2.81% annual inflation to arrive at a an overnight cost in 2007$ of $4,652,551. This represents only SCE&G's 55% share of the total plant cost, so we calculate the total to be $8,459,184. Then, $3,787=$8,459,184/2,234.

[5] Estmated in-service cost of $6,446,564,927. This is the cost for Georgia Power's 45.7% share.
The total cost for the project is therefore $14.107=$6.447/0.457. This is a total cost as incurred which reflects inflation. We back this out assuming the same schedule and inflation assumptions as for SCE&G, and therefore estimate the overnight cost in 2007 dollars as 74% of this total cost as incurred: $10.439=$14.107 * 74%.
Then, $4,745=$10,439,344/2,200.

[6] $3,480=$2,900 * (1.2).

Table 5: Base Case Assumptions and Inputs for the Levelized Cost of Electricity

	Input	Units	Nuclear [A]	Coal [B]	Gas [C]
[1]	Capacity	MW	1,000	1,000	1,000
[2]	Capacity Factor		85%	85%	85%
[3]	Heat rate	Btu/kWh	10,400	8,870	6,800
[4]	Overnight Cost	$/kW	4,000	2,300	850
[5]	Incremental capital costs	$/kW/year	40	27	10
[6]	Fixed O&M Costs	$/kW/year	56	24	13
[7]	Variable O&M Costs	mills/kWh	0.42	3.57	0.41
[8]	Fuel Costs	$/mmBtu	0.67	2.60	7.00
[9]	Waste fee	$/kWh	0.001		
[10]	Decommissioning cost	$ million	700		
[11]	Carbon intensity	kg-C/mmBtu		25.8	14.5
[12]	Inflation Rate		3.0%	3.0%	3.0%
[13]	O&M real escalation		1.0%	1.0%	1.0%
[14]	Fuel real escalation		0.5%	0.5%	0.5%
[15]	Tax Rate		37%	37%	37%
[16]	Debt fraction		50%	60%	60%
[17]	Debt rate		8%	8%	8%
[18]	Equity rate		15%	12%	12%
[19]	WACC (weighted avg cost of capital)		10.0%	7.8%	7.8%
[20]	Construction Schedule				
	Year -5				
	Year -4		10%		
	Year -3		25%	15%	
	Year -2		31%	35%	
	Year -1		25%	35%	50%
	Year 0		10%	15%	50%
[21]	Depreciation Schedule				
	Year 1		5.00%	3.750%	5.000%
	Year 2		9.50%	7.219%	9.500%
	Year 3		8.55%	6.677%	8.550%
	Year 4		7.70%	6.177%	7.700%
	Year 5		6.93%	5.713%	6.930%
	Year 6		6.23%	5.285%	6.230%
	Year 7		5.90%	4.888%	5.900%
	Year 8		5.90%	4.522%	5.900%
	Year 9		5.91%	4.462%	5.910%
	Year 10		5.90%	4.461%	5.900%
	Year 11		5.91%	4.462%	5.910%
	Year 12		5.90%	4.461%	5.900%
	Year 13		5.91%	4.462%	5.910%
	Year 14		5.90%	4.461%	5.900%
	Year 15		5.91%	4.462%	5.910%
	Year 16		2.95%	4.461%	2.950%
	Year 17			4.462%	
	Year 18			4.461%	
	Year 19			4.462%	
	Year 20			4.461%	
	Year 21			2.231%	
[22]	Plant Life		40 years	40 years	40 years

Table 5: Base Case Assumptions and Inputs for the Levelized Cost of Electricity (cont.)

Notes:
Compare to Table A-5.A.4 “Base Case Input Parameters” in the MIT (2003) Future of Nuclear Power study.

[1]	Given as in MIT (2003).
[2]	Given as in MIT (2003).
[3A]	Given as in MIT (2003).
[3B]	Input selected based on results in this paper--see text.
[3C]	Input selected based on results in this paper--see text.
[4]	Input selected based on results in this paper--see text.
[5]	Sets the incremental capital costs to the same ratio with the overnight cost as in the MIT (2003) study.
[5A]	=(20/2,000)*[4A].
[5B]	=(15/1,300)*[4B].
[5C]	=(6/500)*[4C].
[6]	Adjusts the fixed O&M costs from the MIT (2003) study to reflect the general trend in O&M cost between 2002 and 2007 as documented by the US Energy Information Administration.
[6A]	=63*(1.29/1.44).
[6B]	=23*(0.56/0.53).
[6C]	=16*(0.49/0.62).
[7]	Adjusts the variable O&M costs from the MIT (2003) study to reflect the general trend in O&M cost between 2002 and 2007 as documented by the US Energy Information Administration.
[7A]	=0.47*(1.29/1.44).
[7B]	=3.38*(0.56/0.53).
[7C]	=0.52*(0.49/0.62).
[8]	Input selected based on results in this paper--see text.
[9A]	Given as in MIT (2003), consistent with statutory fees.
[10A]	Sets the decommissioning cost to the same ratio with the overnight cost as in the MIT (2003) study. =(350/2,000)*[4A].
[11]	Given as in MIT (2003).
[12]	Given as in MIT (2003).
[13]	Given as in MIT (2003).
[14]	Given as in MIT (2003).
[15]	Given as in MIT (2003).
[16]	Given as in MIT (2003).
[17]	Given as in MIT (2003).
[18]	Given as in MIT (2003).
[19]	=[15]*(1-[14])*[16]+(1-[15])*[17]
[20]	Given as in MIT (2003).
[21]	Modified Accelerated Cost Recovery System, half-year convention as listed in IRS (2007), Table A-1, p. 71
[21A]	15-year schedule.
[21B]	20-year schedule.
[21C]	15-year schedule.
[22]	Given as in MIT (2003).

Table 6A: Cost Cash Flows and Depreciation at a Nuclear Power Plant ($ millions)

	Period [A]	Calendar Year [B]	Construction Costs [C]	Depreciation [D]	Incremental Capital Costs + Decomm. Cost [E]	Non-fuel O&M costs [F]	Fuel Costs [G]	Waste fee [H]
[1]	-4	2009	403					
[2]	-3	2010	1093					
[3]	-2	2011	1396					
[4]	-1	2012	1159					
[5]	0	2013	454					
[6]	1	2014		225	49	74	66	7
[7]	2	2015		428	51	77	68	7
[8]	3	2016		385	52	81	71	7
[9]	4	2017		347	54	84	73	7
[10]	5	2018		312	55	87	76	7
[11]	6	2019		281	57	91	79	7
[12]	7	2020		266	59	94	81	7
[13]	8	2021		266	61	98	84	7
[13]	9	2022		266	62	102	87	7
[14]	10	2023		266	64	106	90	7
[15]	11	2024		266	66	110	93	7
[16]	12	2025		266	68	115	97	7
[17]	13	2026		266	70	120	100	7
[18]	14	2027		266	72	124	104	7
[19]	15	2028		266	74	129	107	7
[20]	16	2029		133	77	135	111	7
[21]	17	2030			79	140	115	7
[22]	18	2031			81	146	119	7
[23]	19	2032			84	152	123	7
[24]	20	2033			86	158	128	7
[25]	21	2034			89	164	132	7
[26]	22	2035			92	171	137	7
[27]	23	2036			94	177	141	7
[28]	24	2037			97	185	146	7
[29]	25	2038			100	192	152	7
[30]	26	2039			103	200	157	7
[31]	27	2040			106	208	162	7
[32]	28	2041			109	216	168	7
[33]	29	2042			113	225	174	7
[34]	30	2043			116	234	180	7
[35]	31	2044			119	243	186	7
[36]	32	2045			123	253	193	7
[37]	33	2046			127	263	200	7
[38]	34	2047			130	274	207	7
[39]	35	2048			134	285	214	7
[40]	36	2049			138	297	222	7
[41]	37	2050			143	309	229	7
[42]	38	2051			147	321	237	7
[43]	39	2052			151	334	246	7
[44]	40	2053			2882	347	254	7

Notes:

[C] =overnight cost * capacity * construction schedule(t) * inflation factor(t).

[D] =sum of [C] * depreciation schedule(t).

[E] =incremental capital cost * capacity * inflation factor(t). In the last year the decommissioning cost * inflation factor is added.

[F] = (fixed O&M cost * capacity + variable O&M cost * output) * inflation factor(t).

[G] = fuel cost * heat rate * output * inflation factor(t).

[H] = waste disposal cost * output. This is not inflated, as the nominal value is fixed by statute.

Table 6B: After-tax Cost Cash Flows at a Nuclear Power Plant ($ millions)

	Period [A]	Calendar Year [B]	Construction Costs Net of Depreciation Tax Shields [C]	Incremental Capital Costs + Decomm. Cost [D]	Non-fuel O&M costs [E]	Fuel Costs + Waste Fee [F]	Net Cash Flow [G]
[1]	-4	2009	403				403
[2]	-3	2010	1,093				1,093
[3]	-2	2011	1,396				1,396
[4]	-1	2012	1,159				1,159
[5]	0	2013	454				454
[6]	1	2014	-83	31	47	46	41
[7]	2	2015	-158	32	49	48	-30
[8]	3	2016	-143	33	51	49	-10
[9]	4	2017	-128	34	53	51	9
[10]	5	2018	-116	35	55	53	27
[11]	6	2019	-104	36	57	54	43
[12]	7	2020	-98	37	59	56	54
[13]	8	2021	-98	38	62	58	59
[13]	9	2022	-99	39	64	60	65
[14]	10	2023	-98	40	67	62	71
[15]	11	2024	-99	42	70	64	76
[16]	12	2025	-98	43	72	66	83
[17]	13	2026	-99	44	75	68	89
[18]	14	2027	-98	46	78	70	96
[19]	15	2028	-99	47	82	72	102
[20]	16	2029	-49	48	85	75	159
[21]	17	2030		50	88	77	215
[22]	18	2031		51	92	80	223
[23]	19	2032		53	95	82	231
[24]	20	2033		54	99	85	239
[25]	21	2034		56	103	88	247
[26]	22	2035		58	107	91	256
[27]	23	2036		59	112	94	265
[28]	24	2037		61	116	97	274
[29]	25	2038		63	121	100	284
[30]	26	2039		65	126	104	294
[31]	27	2040		67	131	107	305
[32]	28	2041		69	136	111	316
[33]	29	2042		71	142	114	327
[34]	30	2043		73	147	118	339
[35]	31	2044		75	153	122	351
[36]	32	2045		77	160	126	363
[37]	33	2046		80	166	131	376
[38]	34	2047		82	173	135	390
[39]	35	2048		85	180	140	404
[40]	36	2049		87	187	144	418
[41]	37	2050		90	194	149	433
[42]	38	2051		93	202	154	449
[43]	39	2052		95	210	160	465
[44]	40	2053		1,816	219	165	2,200

Notes:

[C] = Table 6A column [C](t) - tax rate * Table 6A column [D](t).

[D] = Table 6A column [E](t) * (1-tax rate).

[E] = Table 6A, column [F](t) * (1-tax rate).

[F] = Table 6A, (columns [G]+[H])(t) * (1-tax rate).

[G] = [C]+[D]+[E]+[F].

Table 6C: Valuation of Cost Cash Flows at a Nuclear Power Plant ($ millions)

	Period	Calendar Year	Discount Factor	Construction Costs Net of Depreciation Tax Shields	Incremental Capital Costs + Decomm. Cost	Non-fuel O&M costs	Fuel Costs + Waste Fee	Net Cost Cash Flow
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
[1]	-4	2009	1.465	591				591
[2]	-3	2010	1.332	1,455				1,455
[3]	-2	2011	1.210	1,689				1,689
[4]	-1	2012	1.100	1,275				1,275
[5]	0	2013	1.000	454				454
[6]	1	2014	0.909	-76	28	43	42	37
[7]	2	2015	0.826	-131	26	40	40	-25
[8]	3	2016	0.751	-107	25	38	37	-7
[9]	4	2017	0.683	-88	23	36	35	6
[10]	5	2018	0.620	-72	22	34	33	17
[11]	6	2019	0.564	-59	20	32	31	24
[12]	7	2020	0.513	-50	19	30	29	28
[13]	8	2021	0.466	-46	18	29	27	28
[13]	9	2022	0.423	-42	17	27	25	27
[14]	10	2023	0.385	-38	16	26	24	27
[15]	11	2024	0.350	-34	15	24	22	27
[16]	12	2025	0.318	-31	14	23	21	26
[17]	13	2026	0.289	-28	13	22	20	26
[18]	14	2027	0.263	-26	12	21	18	25
[19]	15	2028	0.239	-24	11	19	17	24
[20]	16	2029	0.217	-11	10	18	16	34
[21]	17	2030	0.197		10	17	15	42
[22]	18	2031	0.179		9	16	14	40
[23]	19	2032	0.163		9	16	13	38
[24]	20	2033	0.148		8	15	13	35
[25]	21	2034	0.135		8	14	12	33
[26]	22	2035	0.122		7	13	11	31
[27]	23	2036	0.111		7	12	10	29
[28]	24	2037	0.101		6	12	10	28
[29]	25	2038	0.092		6	11	9	26
[30]	26	2039	0.084		5	11	9	25
[31]	27	2040	0.076		5	10	8	23
[32]	28	2041	0.069		5	9	8	22
[33]	29	2042	0.063		4	9	7	21
[34]	30	2043	0.057		4	8	7	19
[35]	31	2044	0.052		4	8	6	18
[36]	32	2045	0.047		4	8	6	17
[37]	33	2046	0.043		3	7	6	16
[38]	34	2047	0.039		3	7	5	15
[39]	35	2048	0.035		3	6	5	14
[40]	36	2049	0.032		3	6	5	13
[41]	37	2050	0.029		3	6	4	13
[42]	38	2051	0.027		2	5	4	12
[43]	39	2052	0.024		2	5	4	11
[44]	40	2053	0.022		40	5	4	48
[45]	Total NPV (t=2013)			4,603	448	699	631	6,381
[46]	Item total as % of Project Total			72%	7%	11%	10%	
[47]	Total NPV (t=2007)			2,595	252	394	356	3,598

Notes:

[C] = 1/(1+WACC)^[A]. WACC is given in Table 5.

[D] = Table 6B column [C] * this Table column [C].

[E] = Table 6B column [D] * this Table column [C].

[F] = Table 6B column [E] * this Table column [C].

[G] = Table 6B column [F] * this Table column [C].

[H] = [D]+[E]+[F]+[G].

[45] = sum [1]-[44].

[46D] = [45D]/[45H], and so on.

[47] = [45]*1/(1+WACC)^(2013-2007). WACC is given in Table 5.

Table 6D: The Levelized Cost of Electricity for a Nuclear Power Plant

						Present Value ($ millions)		
							Net Cost	
	Period	Calendar Year	Discount Factor	Price ($/MW)	After-Tax Revenue ($ millions)	After-Tax Revenue	After-Tax Cash Flow	Net Cash Flow
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
[0]	-6	2007	1.773	84				
[1]	-4	2009	1.465	89			591	-591
[2]	-3	2010	1.332	91			1,455	-1,455
[3]	-2	2011	1.210	94			1,689	-1,689
[4]	-1	2012	1.100	97			1,275	-1,275
[5]	0	2013	1.000	100			454	-454
[6]	1	2014	0.909	103	482	438	37	401
[7]	2	2015	0.826	106	497	411	-25	435
[8]	3	2016	0.751	109	512	384	-7	391
[9]	4	2017	0.683	112	527	360	6	353
[10]	5	2018	0.620	116	543	337	17	320
[11]	6	2019	0.564	119	559	315	24	291
[12]	7	2020	0.513	123	576	295	28	268
[13]	8	2021	0.466	126	593	276	28	249
[13]	9	2022	0.423	130	611	259	27	231
[14]	10	2023	0.385	134	629	242	27	215
[15]	11	2024	0.350	138	648	227	27	200
[16]	12	2025	0.318	142	668	212	26	186
[17]	13	2026	0.289	147	688	199	26	173
[18]	14	2027	0.263	151	708	186	25	161
[19]	15	2028	0.239	155	730	174	24	150
[20]	16	2029	0.217	160	752	163	34	129
[21]	17	2030	0.197	165	774	153	42	110
[22]	18	2031	0.179	170	797	143	40	103
[23]	19	2032	0.163	175	821	134	38	96
[24]	20	2033	0.148	180	846	125	35	90
[25]	21	2034	0.135	186	871	117	33	84
[26]	22	2035	0.122	191	897	110	31	78
[27]	23	2036	0.111	197	924	103	29	73
[28]	24	2037	0.101	203	952	96	28	69
[29]	25	2038	0.092	209	981	90	26	64
[30]	26	2039	0.084	215	1,010	84	25	60
[31]	27	2040	0.076	222	1,040	79	23	56
[32]	28	2041	0.069	228	1,072	74	22	52
[33]	29	2042	0.063	235	1,104	69	21	49
[34]	30	2043	0.057	242	1,137	65	19	45
[35]	31	2044	0.052	249	1,171	61	18	42
[36]	32	2045	0.047	257	1,206	57	17	40
[37]	33	2046	0.043	265	1,242	53	16	37
[38]	34	2047	0.039	273	1,280	50	15	35
[39]	35	2048	0.035	281	1,318	47	14	32
[40]	36	2049	0.032	289	1,357	44	13	30
[41]	37	2050	0.029	298	1,398	41	13	28
[42]	38	2051	0.027	307	1,440	38	12	26
[43]	39	2052	0.024	316	1,483	36	11	25
[44]	40	2053	0.022	325	1,528 0	34	48	-15
[45]	Total NPV (t=2013)					6,381	6,381	0

Notes:

Row [0] column [D] is chosen to set row [45] column [H] equal to zero.

[D] = row [0] column [D] * inflation factor(t).

[E] = price(t) * output * inflation factor(t) * (1-tax rate).

[F] = [C]*[E].

[G] = from Table 6C column [H].

[H] = [F]+[G].

[45] = sum [1]-[44].

Table 7: Overnight Costs for Some Planned Coal Plants in the US

	Owner [A]	Name of Plant [B]	Design [C]	Fuel [D]	Capacity MW [E]	Cost at Completion million $ [F]	Projected Commercial Operation Date [G]	Overnight Cost in 2007 US $/kW [H]
[1]	Florida Power & Light	Glades	USC PC	bituminous	1,960	4,424	2013-2014	1,941
[2]	Duke Energy	Cliffside	SC PC	bituminous	800	1,800	2012	1,935
[3]	AMP Ohio	Meigs Co.	SC PC	blend	960	3,257	2014	2,986
[4]	AEP Swepco	John W. Turk Jr.	USC PC	sub-bituminous	600	1,558	2012	2,285

Sources for columns [A]-[G]:

[1] Florida Power & Light (2007a), p. 37, Table III.F.1. .

[2] Duke Power (2005a), (2005b) and (2008).

[3] American Municipal Power-Ohio, Inc. (2007); R.W. Beck (2008a) and (2008b).

[4] Southwestern Electric Power Company (2006a); (2006b); and (2008), p. 20.

Definitions for column [C]:

[1]-[4] USC - ultra-supercritical, SC - supercritical, PC - pulverized coal combustion

Notes for column [H]:

[1] We start by summing the reported power plant costs (incl. land) and 1/2 of transmission costs, which equals $4.424 billion.
To back out the effect of inflation, we multiply by 86%, which is the ratio of this total cost as expended to the overnight cost in 2007 dollars given a 3% inflation rate.
The 3% rate is what FPL used in constructing its estimate, and the 86% figure is derived from the calculations shown in Table 2, with appropriate adjustments made for the construction schedule of a coal plant.
Therefore the total overnight cost in billions 2007 $ is 3.804=4.424 * 86%. Per kW we have: $1,941/kW=$3,804,210/1,960kW.

[2] Starting with the reported $1.8 billion cost, we apply the same 86% ratio as used in [1] to back out inflation. $1.548=$1.800 * 86%. Then, $1,935=$1,548,000/800.

[3] We start with the reported cost of $3.257 billion. To back out the effect of inflation, we multiply by approx. 88%, which is the ratio of this total cost as expended to the overnight cost in 2007 dollars given the 2.3% inflation rate used in the RW Beck study and calculated using a version of Table 2.
The result is: 2,866,160=3,257,000 * 88%. Then, $3,081=$2,866,160/960.
Although the unit is being designed for a blend of bituminous and sub-bituminous coals, the R.W.Beck study, when estimating operating and maintenance costs, that bituminous coals are used.

[4] Starting with the reported cost of $1.558 billion, we apply an approx. 88% ratio to back out inflation: $1,371,040=$1,558,000 * 88%. Then, $2,352=$1,371,040/600.

Table 8A: Cost Cash Flows and Depreciation at a Coal-Fired Power Plant ($ millions)

	Period	Calendar Year	Construction Costs	Depreciation	Incremental Capital Costs	Non-fuel O&M costs	Fuel Costs
	[A]	[B]	[C]	[D]	[E]	[F]	[G]
[1]	-4	2009					
[2]	-3	2010	367				
[3]	-2	2011	916				
[4]	-1	2012	944				
[5]	0	2013	401				
[6]	1	2014		99	33	67	219
[7]	2	2015		190	34	70	227
[8]	3	2016		175	35	73	235
[9]	4	2017		162	36	76	243
[10]	5	2018		150	37	79	251
[11]	6	2019		139	38	82	260
[12]	7	2020		128	39	85	269
[13]	8	2021		119	40	89	279
[13]	9	2022		117	41	92	289
[14]	10	2023		117	43	96	299
[15]	11	2024		117	44	100	309
[16]	12	2025		117	45	104	320
[17]	13	2026		117	47	108	331
[18]	14	2027		117	48	112	343
[19]	15	2028		117	49	117	355
[20]	16	2029		117	51	121	367
[21]	17	2030		117	52	126	380
[22]	18	2031		117	54	131	394
[23]	19	2032		117	56	137	408
[24]	20	2033		117	57	142	422
[25]	21	2034		59	59	148	437
[26]	22	2035			61	154	452
[27]	23	2036			63	160	468
[28]	24	2037			64	167	484
[29]	25	2038			66	173	501
[30]	26	2039			68	180	519
[31]	27	2040			70	188	537
[32]	28	2041			73	195	556
[33]	29	2042			75	203	576
[34]	30	2043			77	211	596
[35]	31	2044			79	220	617
[36]	32	2045			82	228	639
[37]	33	2046			84	238	661
[38]	34	2047			87	247	684
[39]	35	2048			89	257	708
[40]	36	2049			92	268	733
[41]	37	2050			95	278	759
[42]	38	2051			97	290	786
[43]	39	2052			100	301	813
[44]	40	2053			103	313	842

Notes:

[C] =overnight cost * capacity * construction schedule(t) * inflation factor(t).

[D] =sum of [C] * depreciation schedule(t).

[E] =incremental capital cost * capacity * inflation factor(t).

[F] = (fixed O&M cost * capacity + variable O&M cost * output) * inflation factor(t).

[G] = fuel cost * heat rate * output * inflation factor(t).

Table 8B: After-tax Cost Cash Flows at a Coal-Fired Power Plant

	Period [A]	Calendar Year [B]	Construction Costs Net of Depreciation Tax Shields [C]	Incremental Capital Costs [D]	Non-fuel O&M costs [E]	Fuel Costs [F]	Net Cash Flow [G]
[1]	-4	2009					
[2]	-3	2010	367				367
[3]	-2	2011	916				916
[4]	-1	2012	944				944
[5]	0	2013	401				401
[6]	1	2014	-36	21	42	138	164
[7]	2	2015	-70	21	44	143	138
[8]	3	2016	-65	22	46	148	150
[9]	4	2017	-60	22	48	153	163
[10]	5	2018	-56	23	50	158	175
[11]	6	2019	-51	24	52	164	188
[12]	7	2020	-48	25	54	170	200
[13]	8	2021	-44	25	56	176	213
[13]	9	2022	-43	26	58	182	222
[14]	10	2023	-43	27	60	188	232
[15]	11	2024	-43	28	63	195	242
[16]	12	2025	-43	28	65	202	252
[17]	13	2026	-43	29	68	209	263
[18]	14	2027	-43	30	71	216	274
[19]	15	2028	-43	31	74	224	285
[20]	16	2029	-43	32	76	231	297
[21]	17	2030	-43	33	80	240	309
[22]	18	2031	-43	34	83	248	321
[23]	19	2032	-43	35	86	257	335
[24]	20	2033	-43	36	90	266	348
[25]	21	2034	-22	37	93	275	384
[26]	22	2035		38	97	285	420
[27]	23	2036		39	101	295	435
[28]	24	2037		41	105	305	451
[29]	25	2038		42	109	316	467
[30]	26	2039		43	114	327	484
[31]	27	2040		44	118	339	501
[32]	28	2041		46	123	350	519
[33]	29	2042		47	128	363	538
[34]	30	2043		48	133	375	557
[35]	31	2044		50	138	389	577
[36]	32	2045		51	144	402	598
[37]	33	2046		53	150	416	619
[38]	34	2047		55	156	431	641
[39]	35	2048		56	162	446	664
[40]	36	2049		58	169	462	688
[41]	37	2050		60	175	478	713
[42]	38	2051		61	182	495	739
[43]	39	2052		63	190	512	765
[44]	40	2053		65	197	530	793

Notes:

[C] = Table 8A column [C](t) - tax rate * Table 8A column [D](t).

[D] = Table 8A column [E](t) * (1-tax rate).

[E] = Table 8A, column [F](t) * (1-tax rate).

[F] = Table 8A, (columns [G]+[H])(t) * (1-tax rate).

[G] = [C]+[D]+[E]+[F].

Table 8C: Valuation of Cost Cash Flows at a Coal-Fired Power Plant

	Period	Calendar Year	Discount Factor	Construction Costs Net of Depreciation Tax Shields	Incremental Capital Costs	Non-fuel O&M costs	Fuel Costs	Net Cost Cash Flow
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
[1]	-4	2009	1.352					
[2]	-3	2010	1.254	460				460
[3]	-2	2011	1.163	1,065				1,065
[4]	-1	2012	1.078	1,018				1,018
[5]	0	2013	1.000	401				401
[6]	1	2014	0.927	-34	19	39	128	152
[7]	2	2015	0.860	-60	18	38	123	118
[8]	3	2016	0.798	-52	17	37	118	120
[9]	4	2017	0.740	-44	17	35	113	121
[10]	5	2018	0.686	-38	16	34	109	120
[11]	6	2019	0.636	-33	15	33	104	120
[12]	7	2020	0.590	-28	14	32	100	118
[13]	8	2021	0.547	-24	14	31	96	116
[13]	9	2022	0.508	-22	13	29	92	113
[14]	10	2023	0.471	-20	13	28	89	109
[15]	11	2024	0.437	-19	12	27	85	106
[16]	12	2025	0.405	-18	12	26	82	102
[17]	13	2026	0.376	-16	11	26	78	99
[18]	14	2027	0.348	-15	11	25	75	95
[19]	15	2028	0.323	-14	10	24	72	92
[20]	16	2029	0.300	-13	10	23	69	89
[21]	17	2030	0.278	-12	9	22	67	86
[22]	18	2031	0.258	-11	9	21	64	83
[23]	19	2032	0.239	-10	8	21	61	80
[24]	20	2033	0.222	-10	8	20	59	77
[25]	21	2034	0.206	-4	8	19	57	79
[26]	22	2035	0.191		7	18	54	80
[27]	23	2036	0.177		7	18	52	77
[28]	24	2037	0.164		7	17	50	74
[29]	25	2038	0.152		6	17	48	71
[30]	26	2039	0.141		6	16	46	68
[31]	27	2040	0.131		6	15	44	66
[32]	28	2041	0.121		6	15	43	63
[33]	29	2042	0.113		5	14	41	60
[34]	30	2043	0.104		5	14	39	58
[35]	31	2044	0.097		5	13	38	56
[36]	32	2045	0.090		5	13	36	54
[37]	33	2046	0.083		4	12	35	52
[38]	34	2047	0.077		4	12	33	50
[39]	35	2048	0.072		4	12	32	48
[40]	36	2049	0.066		4	11	31	46
[41]	37	2050	0.062		4	11	29	44
[42]	38	2051	0.057		4	10	28	42
[43]	39	2052	0.053		3	10	27	41
[44]	40	2053	0.049		3	10	26	39
[45]	Total NPV (t=2013)			2,446	358	849	2,574	6,226
[46]	Item total as % of Project Total			39%	6%	14%	41%	
[47]	Total NPV (t=2007)			1,556	228	540	1,638	3,962

Notes:

[C] = 1/(1+WACC)^[A]. WACC is given in Table 5.
[D] = Table 8B column [C] * this Table column [C].
[E] = Table 8B column [D] * this Table column [C].
[F] = Table 8B column [E] * this Table column [C].
[G] = Table 8B column [F] * this Table column [C].
[H] = [D]+[E]+[F]+[G].
[45] = sum [1]-[44].
[46D] = [45D]/[45H], and so on.
[47] = [45]*1/(1+WACC)^(2013-2007). WACC is given in Table 5.

Table 8D: The Levelized Cost of Electricity for a Coal-Fired Power Plant

						Present Value		
	Period	Calendar Year	Discount Factor	Price	After-Tax Revenue	After-Tax Revenue	Net Cost After-Tax Cash Flow	Net Cash Flow
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
[0]	-6	2007	1.571	62				
[1]	-4	2009	1.352	66				
[2]	-3	2010	1.254	68			460	-460
[3]	-2	2011	1.163	70			1,065	-1,065
[4]	-1	2012	1.078	72			1,018	-1,018
[5]	0	2013	1.000	74			401	-401
[6]	1	2014	0.927	76	358	332	152	179
[7]	2	2015	0.860	78	368	317	118	198
[8]	3	2016	0.798	81	379	303	120	183
[9]	4	2017	0.740	83	391	289	121	169
[10]	5	2018	0.686	86	403	276	120	156
[11]	6	2019	0.636	88	415	264	120	144
[12]	7	2020	0.590	91	427	252	118	134
[13]	8	2021	0.547	94	440	241	116	124
[13]	9	2022	0.508	97	453	230	113	117
[14]	10	2023	0.471	99	467	220	109	111
[15]	11	2024	0.437	102	481	210	106	104
[16]	12	2025	0.405	105	495	200	102	98
[17]	13	2026	0.376	109	510	192	99	93
[18]	14	2027	0.348	112	525	183	95	88
[19]	15	2028	0.323	115	541	175	92	83
[20]	16	2029	0.300	119	557	167	89	78
[21]	17	2030	0.278	122	574	159	86	74
[22]	18	2031	0.258	126	591	152	83	70
[23]	19	2032	0.239	130	609	146	80	66
[24]	20	2033	0.222	134	627	139	77	62
[25]	21	2034	0.206	138	646	133	79	54
[26]	22	2035	0.191	142	665	127	80	47
[27]	23	2036	0.177	146	685	121	77	44
[28]	24	2037	0.164	150	706	116	74	42
[29]	25	2038	0.152	155	727	111	71	40
[30]	26	2039	0.141	160	749	106	68	37
[31]	27	2040	0.131	164	771	101	66	35
[32]	28	2041	0.121	169	794	96	63	33
[33]	29	2042	0.113	174	818	92	60	32
[34]	30	2043	0.104	180	843	88	58	30
[35]	31	2044	0.097	185	868	84	56	28
[36]	32	2045	0.090	190	894	80	54	27
[37]	33	2046	0.083	196	921	77	52	25
[38]	34	2047	0.077	202	949	73	50	24
[39]	35	2048	0.072	208	977	70	48	22
[40]	36	2049	0.066	214	1,006	67	46	21
[41]	37	2050	0.062	221	1,037	64	44	20
[42]	38	2051	0.057	227	1,068	61	42	19
[43]	39	2052	0.053	234	1,100	58	41	18
[44]	40	2053	0.049	241	1,133	56	39	17
[45]	Total NPV (t=2013)					6,226	6,226	0

Notes:

Row [0] column [D] is chosen to set row [45] column [H] equal to zero.

[D] = row [0] column [D] * inflation factor(t).

[E] = price(t) * output * inflation factor(t) * (1-tax rate).

[F] = [C]*[E].

[G] = from Table 8C column [H].

[H] = [F]+[G].

[45] = sum [1]-[44].

Table 9: Overnight Costs for Some Completed or Planned Gas Plants (CCGT) in the US

	Owner	Name of Plant	Design	Cost adders	Capacity	Heat rate (HHV)	Cost Est. Date	Commercial Operation Date		Overnight Cost $Year Est.		Overnight Cost $2007	Value of cost adders	Overnight cost without adders
					MW	BTU/kWh				million $	$/kW	$/kW	$/kW	$/kW
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]		[I]	[J]	[K]	[L]	[M]
[1]	Progress Energy (Florida)	Hines Energy Complex 4	2-on-1	co-location, GE 7FA turbine	461	7,079	2004	2007	*	222	480	652	-43	695
[2]	Caithness Energy	Blythe Energy Project II	2-on-1	co-location, Siemens V84.3a turbine, chillers, duct firing	520	6,763	2005	2007	*	250	481	589	-11	600
[3]	Portland General Electric	Port Westward	1-on-1	Mitsubishi M501G1 turbine, evaporative chillers, 25MW duct firing	414	6,700	2005	2007	*	285	689	844	32	812
[4]	NV Energy (Sierra Pacific Power)	Tracy	2-on-1	co-location, GE 7FA turbine, dry cooling	514		2005	2008	*	421	819	1,004	5	999
[5]	PG&E	Colusa	2-on-1	GE 7FA turbine, dry cooling, evaporative chillers, duct firing	660	6,846	2006	2010		475	720	797	80	717
[6]	Reliant Energy	San Gabriel	2-on-1	brownfield site, co-location, Siemens 5000F turbine, dry cooling, evaporative chillers, duct firing	656	7,062	2007	2010		520	793	793	48	745
[7]	Progress Energy (Carolinas)	Richmond	2-on-1	co-location, duct firing	570		2008	2011		725	1,272	1,235	-22	1,257
[8]	Northern California Power Agency	Lodi	1-on-1	co-location, GE 7FA turbine, reclaimed water cooling, 25 MW peak duct firing	255	6,797	2008	2012		275	1,078	1,047	-22	1,069
[9]	Competitive Power Ventures	Vaca Station	2-on-1	reclaimed water cooling (mechanical draft), evaporative chillers, duct firing	660	6,885	2008	2013		475	720	699	32	667
[10]	Macquarie (Federal Power)	Avenal Energy Project	2-on-1	GE 7FA turbine, dry cooling, mechanical chillers, duct firing	600	6,941	2008	2012		530	883	858	80	778
[11]	NV Energy (Nevada Power)	Harry Allen	2-on-1	co-location, dry cooling	500		2008	2012		614	1,228	1,192	5	1,187
[12]	Florida Power & Light	West County Energy Center 3	3-on-1	co-location, reclaimed water cooling	1,219	6,582	2011	2011		736	604	536	-43	579

* denotes completed facility as of January 2009

Sources for columns [A]-[K]:
[1] Progress Energy (2008), ch. 3, p. 8; State of Florida Siting Board (2005).
[2] California Energy Commission (2005), section 3
[3] King (2008), pp. 7-8; Mody (2007), p. 2.
[4] Peltier (2008); NV Energy (2007), p. 23.
[5] E&L Westcoast (2006), section 3.
[6] Reliant Energy (2007), section 2.
[7] Progress Energy Carolinas (2008).
[8] Northern California Power Agency (2008), section 2.
[9] Competitive Power Ventures (2008), section 2.
[10] Avenal Energy [Federal Power] (2008), section 2.
[11] NV Energy (2008), p. 13.
[12] Florida Power & Light (2008), section V.52, p. 19.

Notes for column [K]:
For cost estimates reported for years after 2007, overnight costs in 2007 are adjusted based on 3% inflation. Overnight costs in 2007 for completed plants are adjusted based on 10.7% annual cost escalation.
[1] Progress Energy cited a value of zero dollars for cost escalation from base year 2006.
[3] Overnight cost figure is raw cost as reported by King.

Notes for columns [L] and [M]:
See 'Ancillary Calculations' for documentation of cost adders, reported in Klein (2007), pp. 42-44.

Table 10A: Cost Cash Flows and Depreciation at a Gas-Fired Power Plant

	Period [A]	Calendar Year [B]	Construction Costs [C]	Depreciation [D]	Incremental Capital Costs [E]	Non-fuel O&M costs [F]	Fuel Costs [G]
[1]	-4	2009					
[2]	-3	2010					
[3]	-2	2011					
[4]	-1	2012	493				
[5]	0	2013	507				
[6]	1	2014		50	13	17	452
[7]	2	2015		95	13	17	468
[8]	3	2016		86	13	18	484
[9]	4	2017		77	14	19	501
[10]	5	2018		69	14	20	519
[11]	6	2019		62	15	20	537
[12]	7	2020		59	15	21	556
[13]	8	2021		59	15	22	575
[13]	9	2022		59	16	23	595
[14]	10	2023		59	16	24	616
[15]	11	2024		59	17	25	638
[16]	12	2025		59	17	26	661
[17]	13	2026		59	18	27	684
[18]	14	2027		59	18	28	708
[19]	15	2028		59	19	29	733
[20]	16	2029		30	20	30	758
[21]	17	2030			20	31	785
[22]	18	2031			21	33	813
[23]	19	2032			21	34	841
[24]	20	2033			22	35	871
[25]	21	2034			23	37	901
[26]	22	2035			23	38	933
[27]	23	2036			24	40	966
[28]	24	2037			25	41	1000
[29]	25	2038			26	43	1035
[30]	26	2039			26	45	1071
[31]	27	2040			27	47	1109
[32]	28	2041			28	48	1148
[33]	29	2042			29	50	1188
[34]	30	2043			30	52	1230
[35]	31	2044			30	55	1273
[36]	32	2045			31	57	1318
[37]	33	2046			32	59	1364
[38]	34	2047			33	61	1412
[39]	35	2048			34	64	1462
[40]	36	2049			35	66	1513
[41]	37	2050			36	69	1567
[42]	38	2051			37	72	1622
[43]	39	2052			39	75	1679
[44]	40	2053			40	78	1738

Notes:

[C] =overnight cost * capacity * construction schedule(t) * inflation factor(t).

[D] =sum of [C] * depreciation schedule(t).

[E] =incremental capital cost * capacity * inflation factor(t).

[F] = (fixed O&M cost * capacity + variable O&M cost * output) * inflation factor(t).

[G] = fuel cost * heat rate * output * inflation factor(t).

Table10B: After-tax Cost Cash Flows at a Gas-Fired Power Plant

	Period [A]	Calendar Year [B]	Construction Costs Net of Depreciation Tax Shields [C]	Incremental Capital Costs [D]	Non-fuel O&M costs [E]	Fuel Costs [F]	Net Cash Flow [G]
[1]	-4	2009					
[2]	-3	2010					
[3]	-2	2011					
[4]	-1	2012	493				493
[5]	0	2013	507				507
[6]	1	2014	-19	8	11	285	284
[7]	2	2015	-35	8	11	295	278
[8]	3	2016	-32	8	11	305	293
[9]	4	2017	-28	9	12	316	308
[10]	5	2018	-26	9	12	327	322
[11]	6	2019	-23	9	13	338	337
[12]	7	2020	-22	9	13	350	351
[13]	8	2021	-22	10	14	362	364
[13]	9	2022	-22	10	14	375	378
[14]	10	2023	-22	10	15	388	392
[15]	11	2024	-22	11	16	402	406
[16]	12	2025	-22	11	16	416	421
[17]	13	2026	-22	11	17	431	437
[18]	14	2027	-22	12	18	446	453
[19]	15	2028	-22	12	18	462	470
[20]	16	2029	-11	12	19	478	498
[21]	17	2030		13	20	495	527
[22]	18	2031		13	21	512	546
[23]	19	2032		13	21	530	565
[24]	20	2033		14	22	549	585
[25]	21	2034		14	23	568	605
[26]	22	2035		15	24	588	627
[27]	23	2036		15	25	609	649
[28]	24	2037		16	26	630	672
[29]	25	2038		16	27	652	695
[30]	26	2039		17	28	675	720
[31]	27	2040		17	29	699	745
[32]	28	2041		18	31	723	771
[33]	29	2042		18	32	749	799
[34]	30	2043		19	33	775	827
[35]	31	2044		19	34	802	856
[36]	32	2045		20	36	830	886
[37]	33	2046		20	37	860	917
[38]	34	2047		21	39	890	949
[39]	35	2048		22	40	921	983
[40]	36	2049		22	42	953	1,018
[41]	37	2050		23	44	987	1,053
[42]	38	2051		24	45	1,022	1,091
[43]	39	2052		24	47	1,058	1,129
[44]	40	2053		25	49	1,095	1,169

Notes:

[C] = Table 10A column [C](t) - tax rate * Table 10A column [D](t).

[D] = Table 10A column [E](t) * (1-tax rate).

[E] = Table 10A, column [F](t) * (1-tax rate).

[F] = Table 10A, (columns [G]+[H])(t) * (1-tax rate).

[G] = [C]+[D]+[E]+[F].

Table 10C: Valuation of Cost Cash Flows at a Gas-Fired Power Plant

	Period [A]	Calendar Year [B]	Discount Factor [C]	Construction Costs Net of Depreciation Tax Shields [D]	Incremental Capital Costs [E]	Non-fuel O&M costs [F]	Fuel Costs [G]	Net Cost Cash Flow [H]
[1]	-4	2009	1.352					
[2]	-3	2010	1.254					
[3]	-2	2011	1.163					
[4]	-1	2012	1.078	531				531
[5]	0	2013	1.000	507				507
[6]	1	2014	0.927	-17	7	10	264	264
[7]	2	2015	0.860	-30	7	9	253	240
[8]	3	2016	0.798	-25	7	9	243	234
[9]	4	2017	0.740	-21	6	9	234	228
[10]	5	2018	0.686	-18	6	8	224	221
[11]	6	2019	0.636	-15	6	8	215	215
[12]	7	2020	0.590	-13	6	8	207	207
[13]	8	2021	0.547	-12	5	8	198	199
[13]	9	2022	0.508	-11	5	7	190	192
[14]	10	2023	0.471	-10	5	7	183	184
[15]	11	2024	0.437	-10	5	7	176	177
[16]	12	2025	0.405	-9	4	7	169	171
[17]	13	2026	0.376	-8	4	6	162	164
[18]	14	2027	0.348	-8	4	6	155	158
[19]	15	2028	0.323	-7	4	6	149	152
[20]	16	2029	0.300	-3	4	6	143	149
[21]	17	2030	0.278	0	4	5	137	146
[22]	18	2031	0.258	0	3	5	132	141
[23]	19	2032	0.239	0	3	5	127	135
[24]	20	2033	0.222	0	3	5	122	130
[25]	21	2034	0.206	0	3	5	117	124
[26]	22	2035	0.191		3	5	112	119
[27]	23	2036	0.177		3	4	108	115
[28]	24	2037	0.164		3	4	103	110
[29]	25	2038	0.152		2	4	99	106
[30]	26	2039	0.141		2	4	95	102
[31]	27	2040	0.131		2	4	91	97
[32]	28	2041	0.121		2	4	88	94
[33]	29	2042	0.113		2	4	84	90
[34]	30	2043	0.104		2	3	81	86
[35]	31	2044	0.097		2	3	78	83
[36]	32	2045	0.090		2	3	75	80
[37]	33	2046	0.083		2	3	72	76
[38]	34	2047	0.077		2	3	69	73
[39]	35	2048	0.072		2	3	66	70
[40]	36	2049	0.066		1	3	63	68
[41]	37	2050	0.062		1	3	61	65
[42]	38	2051	0.057		1	3	58	62
[43]	39	2052	0.053		1	2	56	60
[44]	40	2053	0.049		1	2	54	57
[45]	Total NPV (t=2013)			822	138	211	5,312	6,482
[46]	Item total as % of Project Total			13%	2%	3%	82%	
[47]	Total NPV (t=2007)			523	88	134	3,380	4,125

Notes:

[C] = 1/(1+WACC)^[A]. WACC is given in Table 5.
[D] = Table 10B column [C] * this Table column [C].
[E] = Table 10B column [D] * this Table column [C].
[F] = Table 10B column [E] * this Table column [C].
[G] = Table 10B column [F] * this Table column [C].
[H] = [D]+[E]+[F]+[G].
[45] = sum [1]-[44].
[46D] = [45D]/[45H], and so on.
[47] = [45]*1/(1+WACC)^(2013-2007). WACC is given in Table 5.

Table 10D: The Levelized Cost of Electricity for a Gas-Fired Power Plant

	Period	Calendar Year	Discount Factor	Price	After-Tax Revenue	Present Value After-Tax Revenue	Present Value Net Cost After-Tax Cash Flow	Present Value Net Cash Flow
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
[0]	-6	2007	1.571	65				
[1]	-4	2009	1.352	68				
[2]	-3	2010	1.254	70				
[3]	-2	2011	1.163	73				
[4]	-1	2012	1.078	75			531	-531
[5]	0	2013	1.000	77			507	-507
[6]	1	2014	0.927	79	372	345	264	82
[7]	2	2015	0.860	82	384	330	240	90
[8]	3	2016	0.798	84	395	315	234	81
[9]	4	2017	0.740	87	407	301	228	73
[10]	5	2018	0.686	89	419	288	221	66
[11]	6	2019	0.636	92	432	275	215	60
[12]	7	2020	0.590	95	445	262	207	55
[13]	8	2021	0.547	98	458	251	199	51
[13]	9	2022	0.508	100	472	239	192	48
[14]	10	2023	0.471	104	486	229	184	44
[15]	11	2024	0.437	107	500	219	177	41
[16]	12	2025	0.405	110	515	209	171	38
[17]	13	2026	0.376	113	531	199	164	35
[18]	14	2027	0.348	116	547	190	158	33
[19]	15	2028	0.323	120	563	182	152	30
[20]	16	2029	0.300	124	580	174	149	25
[21]	17	2030	0.278	127	598	166	146	20
[22]	18	2031	0.258	131	616	159	141	18
[23]	19	2032	0.239	135	634	152	135	17
[24]	20	2033	0.222	139	653	145	130	15
[25]	21	2034	0.206	143	673	138	124	14
[26]	22	2035	0.191	148	693	132	119	13
[27]	23	2036	0.177	152	714	126	115	11
[28]	24	2037	0.164	157	735	121	110	10
[29]	25	2038	0.152	161	757	115	106	9
[30]	26	2039	0.141	166	780	110	102	8
[31]	27	2040	0.131	171	803	105	97	8
[32]	28	2041	0.121	176	827	100	94	7
[33]	29	2042	0.113	182	852	96	90	6
[34]	30	2043	0.104	187	878	92	86	5
[35]	31	2044	0.097	193	904	87	83	5
[36]	32	2045	0.090	198	931	84	80	4
[37]	33	2046	0.083	204	959	80	76	3
[38]	34	2047	0.077	210	988	76	73	3
[39]	35	2048	0.072	217	1,017	73	70	2
[40]	36	2049	0.066	223	1,048	70	68	2
[41]	37	2050	0.062	230	1,079	66	65	2
[42]	38	2051	0.057	237	1,112	64	62	1
[43]	39	2052	0.053	244	1,145	61	60	1
[44]	40	2053	0.049	251	1,179	58	57	1
[45]	Total NPV (t=2013)					6,482	6,482	0

Notes:

Row [0] column [D] is chosen to set row [45] column [H] equal to zero.

[D] = row [0] column [D] * inflation factor(t).

[E] = price(t) * output * inflation factor(t) * (1-tax rate).

[F] = [C]*[E].

[G] = from Table 10C column [H].

[H] = [F]+[G].

[45] = sum [1]-[44].

Figure 1: Summary Results for the Levelized Cost of Electricity from Alternative Sources

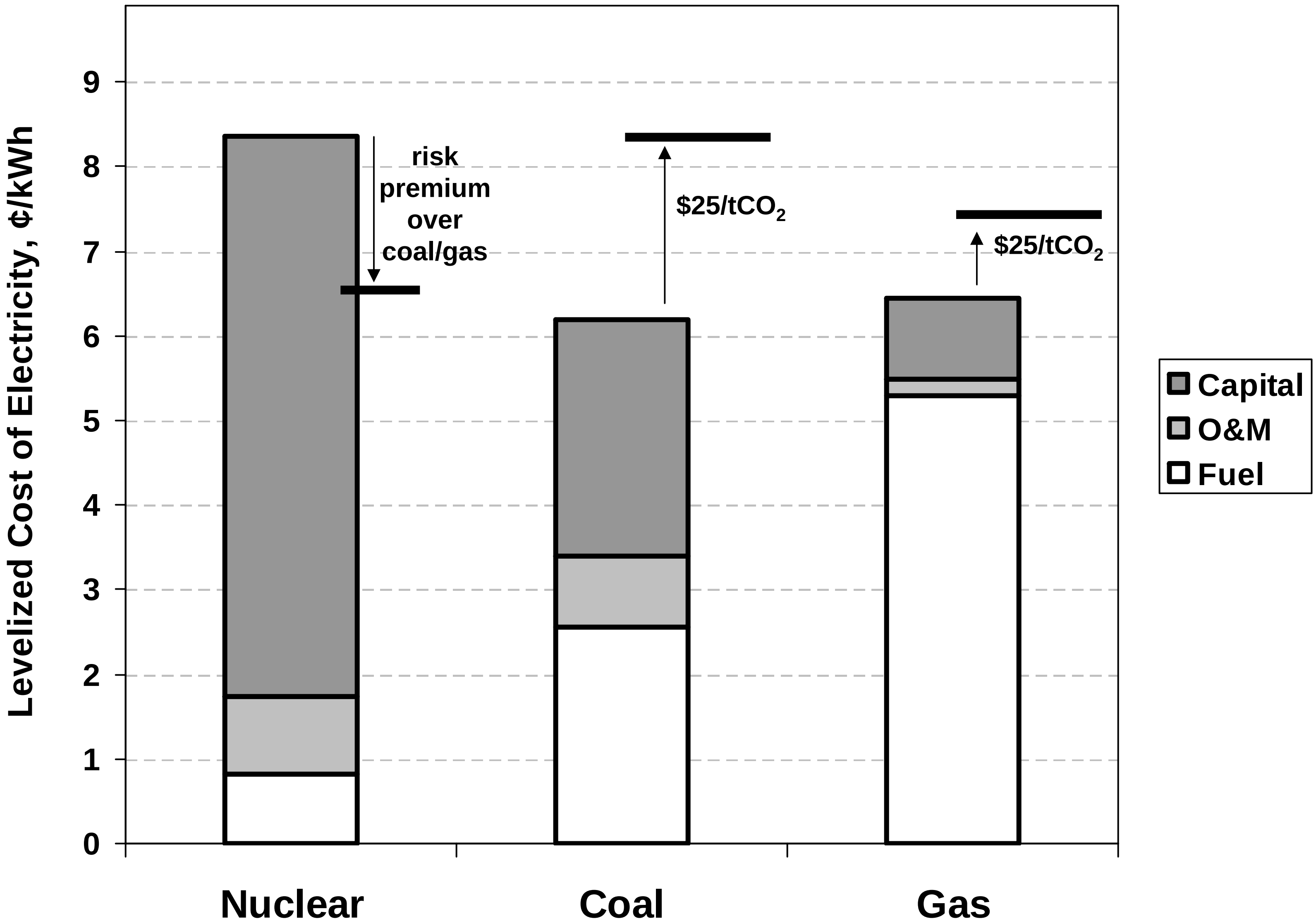

Figure 2: Summary of Evolving Overnight Cost of Nuclear

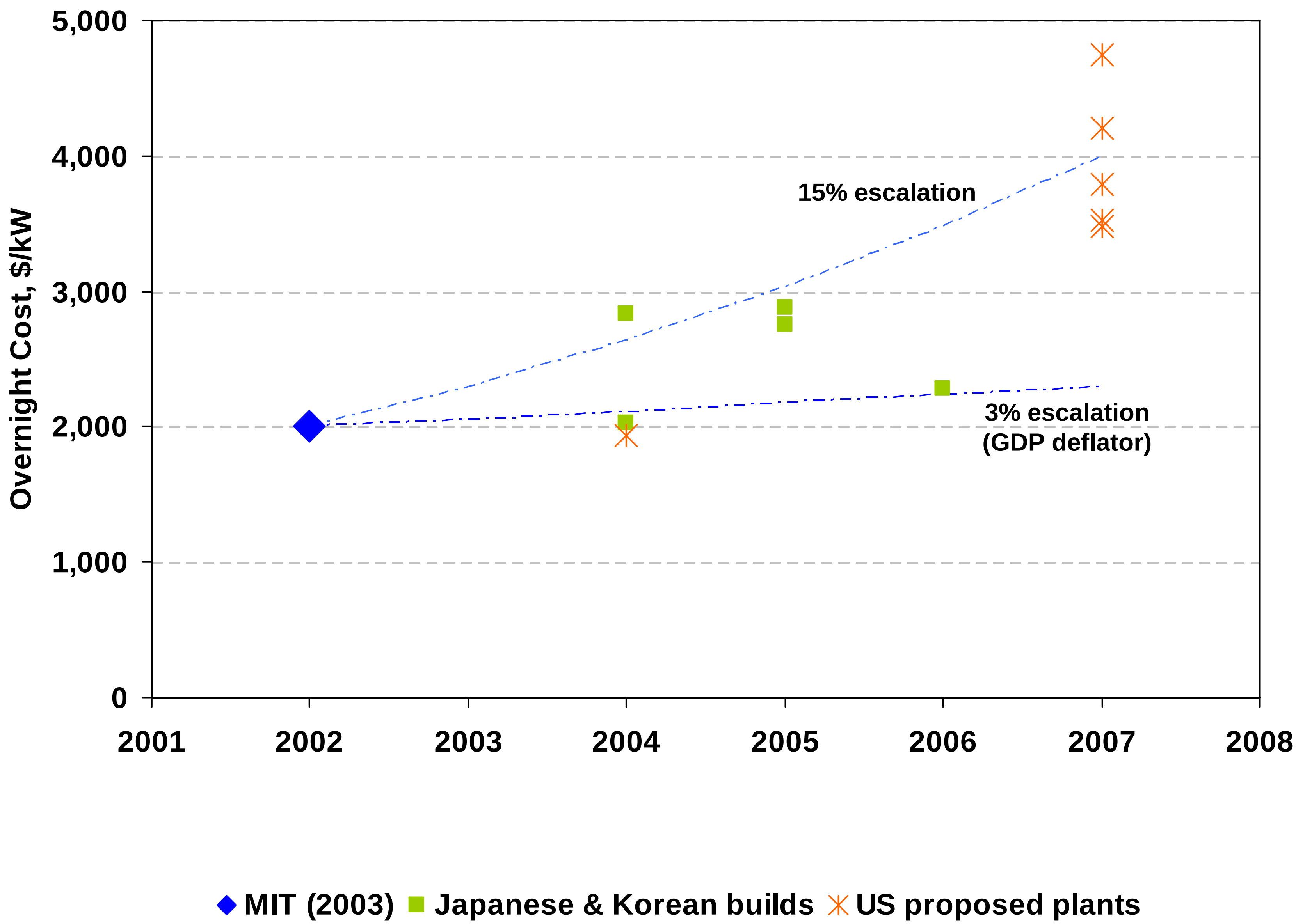

Figure 3: Summary of Evolving Overnight Cost of Coal

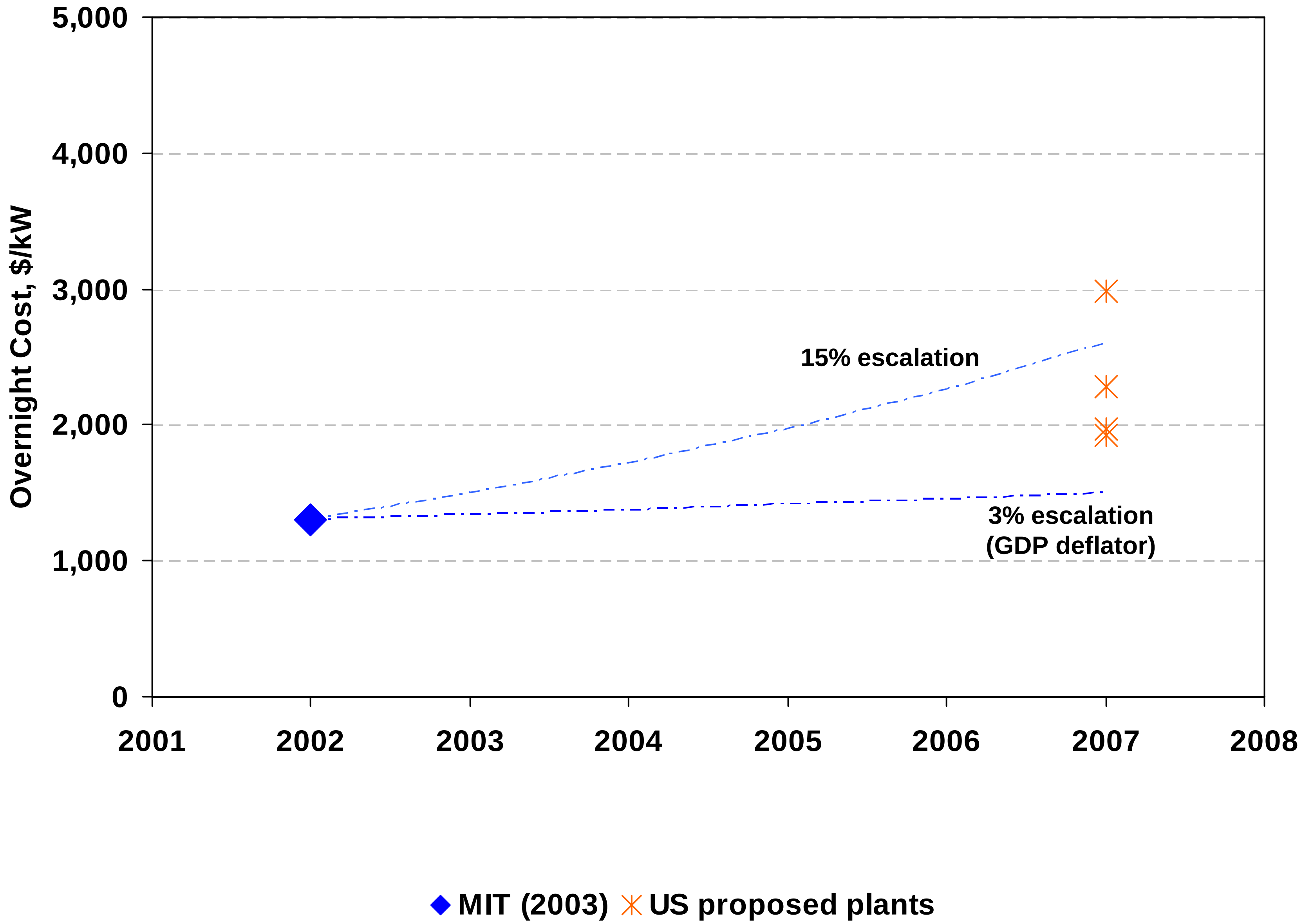

Figure 4: Spot Price of Central Appalachian Coal, 1984-2008