*Technical Paper*

# Investing in MegaProjects:
## A Comparison of Costs and Risks

*By*

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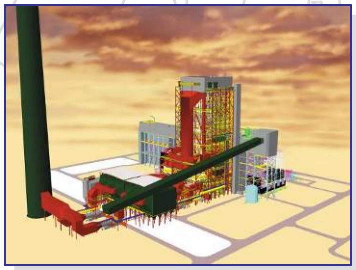

*Presented at*

**POWER-GEN 2005**
**Las Vegas, Nevada**

*December 6, 2005*

Shaw® Stone & Webster Management Consultants, Inc.

# Investing in MegaProjects:
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In response to the growing interest in planning, financing, and implementing new large-scale coal and nuclear power plant projects, Stone & Webster Management Consultants has prepared life-cycle cost calculations for subcritical and supercritical pulverized coal, circulating fluidized bed, integrated gasification combined cycle, and new nuclear projects. Each of these plant types has different costs, lead-times, performance, and risk profiles that must be considered as a result of the variations in technology, environmental requirements, and regulation.

This paper presents a consistent comparison of the economics and risks of representative designs that are being considered in the power marketplace for large new projects requiring investments approaching $1B or larger, termed "MegaProjects". Major plant design and performance features are presented, along with estimates of permitting and construction lead times, construction cost, heat rates, forced and scheduled outage projections, operating and maintenance costs, and the impact of possible changes in environmental regulation. Major risk profiles are also identified, including the relative magnitude of technology risk, implementation risk, and performance risk. Conclusions are presented that suggest which key risk issues will need to be addressed to support successful MegaProjects.

### Why New Coal-Fired MegaProjects?

There are over 150 new coal-fired plants being considered by various developers and regulated power generators for a variety of reasons, including:

- Recent increases in oil and gas prices have pushed the fuel and variable operating costs of many existing plants well beyond what is required to build and operate new coal units, supporting projections that revenues from new coal projects will exceed costs and required return on investment.
- Need for new capacity is growing as a result of load growth and the projected retirement of older units, partly due to increasing costs of environmental compliance.

- New coal technologies provide the opportunity for more cost effective environmental compliance than retrofitting some of the older, smaller units. State of the art control technologies can reduce air emissions to levels approaching oil and gas fired units.
- Coal as a fuel has positive social, security and planning benefits, including more stable long-term power generation costs, reliability of fuel supply, diversity of fuel supply and domestic sourcing which benefits local economies.
- Many advanced coal technologies, especially supercritical pulverized coal and new circulating fluid bed boiler designs, are recognized by the financial community to have acceptable technical risk to support confidence in project completion, performance, cost projections and plant availability.
- Some advanced coal technologies support $CO_2$ capture and sequestration, which target longer term environmental goals but incur severe cost and performance penalties.

## Why New Nuclear MegaProjects?

There are over 20 advanced design nuclear units in the planning or permitting stage, driven by the same economic and environmental forces that are opening the market for new coal plants.

In addition, the Energy Policy Act of 2005 provides substantial support for first-of-a-kind costs, implementation of a new regulatory process, mitigation of construction delay risk, loan guarantees, and a performance tax credit. The magnitude of these incentives should be sufficient to make the first few units competitive in local power markets. These incentives have now created competition and a race among developers to take advantage of the larger incentives for the first units.

The recent history of the U.S. nuclear fleet has demonstrated dramatic improvements in safety, plant availability, operating economics, and overall profitability. Consolidation of existing plants is expected to continue to allow improved fleet economics and better optimization of technical support, regulatory compliance and maintenance costs.

New nuclear units provide the largest improvement in emissions, including short term regulated stack emissions as well as long term major reductions in $CO_2$ emissions. The value of these displaced emissions is likely to grow, further enhancing the projected value of new nuclear units.

Substantial increases in public support for new nuclear reactors have been measured in several polls and are increasingly evident in the media and public forums. Many states have been aggressively competing for the first few nuclear projects and have offered substantial incentives to take advantage of socioeconomic benefits provided by these projects.

Major improvements in nuclear power generating technology provide cost reductions, simplification in designs, shorter construction periods, reduced susceptibility to operator error, higher availability (shorter refueling outages), and dramatically higher safety margins. Commercial demonstration of advanced gas cooled reactor technology should provide the option for smaller plant modules and eliminate public safety concerns regarding reactor accidents.

Expected completion of the national high level nuclear waste repository in Nevada over the next decade should reduce and ultimately eliminate concerns regarding disposition and liabilities associated with spent fuel.

## Candidate Technology Profiles

Several designs were selected to illustrate the emerging competitive economics of new coal and nuclear units with conventional gas fired combined cycle plants. Unless otherwise indicated, plant designs were derived from numerous planning studies performed for various clients by Stone & Webster Management Consultants. For coal technologies, plant sizes on the order of 500 MW were considered to facilitate comparisons.

**Subcritical Pulverized Coal** -- New subcritical pulverized coal units are being considered for applications that involve smaller application sizes and low fuel costs, and for owners that are more comfortable with this boiler technology. Subcritical coal boiler technology has enjoyed a long successful history in the U.S. market with strong performance and reliability. A single 500 MW unit is considered, with one boiler, one steam turbine-generator, evaporative mechanical cooling towers, and state of the art emission control technology.

**Supercritical Pulverized Coal** – New supercritical pulverized coal units are planned for applications that involve larger boilers and more expensive fuels, where the lower heat rates offered by a supercritical steam cycle are most beneficial. A single 500 MW unit is considered, with one boiler, one steam turbine-generator, evaporative mechanical cooling towers, and state of the art emission control technology.

**Subcritical Circulating Fluid Bed Coal** – New CFBs are often planned for applications utilizing lower quality coals or opportunity fuels, where limestone costs are low and spent bed material can be beneficially used or cheaply disposed. In some cases, CFBs are considered for mainstream coal power applications and can compete with pulverized coal units. Two 250 MW CFB boilers are considered each powering a steam turbine-generator, with evaporative mechanical draft cooling towers and state-of-the-art emission control technology. Larger size CFB boilers approaching 500 MW are now being offered commercially, but the smaller boiler sizes are used to represent proven technology.

**Integrated Gasification Combined Cycle** – New IGCC plants are being considered to take advantage of higher power cycle efficiency and lower emissions. This technology is also being considered for demonstration by DOE to provide the opportunity to remove $CO_2$ at lower cost and performance penalties. A range of gasification technologies is being considered for various project applications. This paper considers an oxygen blown high temperature entrained gasifier with full heat recovery, powering two combustion turbines. Waste heat from the gas turbines is recovered in a single steam turbine-generator with evaporative mechanical draft cooling towers and state-of-the-art emission control technology, providing a total plant net capability of about 540 MW.

**Advanced Light Water Reactors** – Most of the currently planned U.S. nuclear projects utilize advanced boiling water reactor designs offered by GE (GE Advanced Boiling Water Reactor “ABWR” and GE Economically Simplified Boiling Water Reactor “ESBWR”), and advanced pressurized water reactor designs by Westinghouse (AP1000) and Areva (EPR). Since engineering for many of these designs is still underway and public information on their economics is very limited, the 1371 MW GE ABWR was included in this evaluation based on a recent published study by TVA. This design is based on a two unit application with some shared benefits from common facilities and site work. (Reference "ABWR Cost/Schedule/COL Project at TVA's Bellefonte Site," TVA, August 2005, DOE Report DE-AI07-04ID14620)

**High Temperature Gas Cooled Reactors –** Although not yet certified in the U.S., a 168 MW PBMR (Pebble Bed Modular Reactor) demonstration project is underway in South Africa scheduled for commercial operation in 2011. Current plans by PBMR include certification in the U.S. for power and process heat applications for projects that could achieve commercial operation in the U.S. by about 2016. One module of a four-module plant design is considered, where the four modules share the benefits of common facilities and site work. Planning assumptions for this design were obtained directly from PBMR based on expected volume of projected commercial orders.

**Gas Fired Combined Cycles –** Several new gas fired combined cycle plants are still being implemented despite high gas prices, driven by their short implementation times and low capital costs. A 500 MW configuration is considered using two combustion turbines, a single steam turbine-generator, backup distillate oil firing capability, and an evaporative mechanical draft cooling system.

## Cost and Economic Assumptions

The following cost and economic assumptions were used to perform the analysis:

- Capital and operating costs were calculated on a consistent basis for all technologies in order to provide, based on the authors' judgment, a consistent but only indicative comparison for the purposes of this paper. It should be noted that the recent surge in demand for new plants may result in significant increases in major equipment pricing beyond the costs assumed for this paper.
- Commercial operation in January 2006 is assumed to minimize the impact of escalation assumptions that add uncertainty to the comparison.
- Construction interest rate is assumed at 8%.
- EPC contracts have firm cost and schedule provisions.
- PBMR design and cost assumptions are somewhat speculative pending completion of the demonstration project in South Africa and U.S. technology certification.
- Owner's costs include project development, environmental permitting and COL (combined NRC construction and operating license), financing costs, project management. The cost of technology certification and first-of-a-kind engineering costs are not included. Land cost is not included since a lot of projects are being planned at existing power plant sites.
- An owner's contingency allowance of 5% of the total EPC and owner's costs is included. This can vary widely depending on the level of confidence in project implementation risk management.

- Transmission system reinforcements are charged at $100/kW for the 500MW and larger units.
- Capital cost recovery is assumed to be 13%/year, consistent with public utility financing costs and low perceived project risks.
- A discount rate of 10% is assumed consistent with current interest rates and public utility financing assumptions.
- O&M cost growth is assumed to be 2.5%/yr.
- Fuel cost growth is assumed to be 3.5%/yr for coal and nuclear, 5%/yr for natural gas.
- Coal fuel costs are assumed to be $1.50 per MMBtu; nuclear fuel cost is assumed to be equivalent to $5/MWh; natural gas price is assumed at $7/MMBtu and $11/MMBtu to represent a range of possibilities.
- A 30 year economic life is assumed consistent with public utility financing assumptions.
- General inflation of 1-2% is included in the above cost growth assumptions.
- No Energy Policy Act supports or credits are included in the analysis directly.

These assumptions can vary widely between projects and financing approaches and were selected only to prove a consistent indicative basis for comparison.

## Capital Requirements

A comparison of total capital investment required for each plant in $2006 dollars is shown in Figure 1. Figure 2 presents these values based on $/net kW.

**Figure 1 – Total Capital Investment**

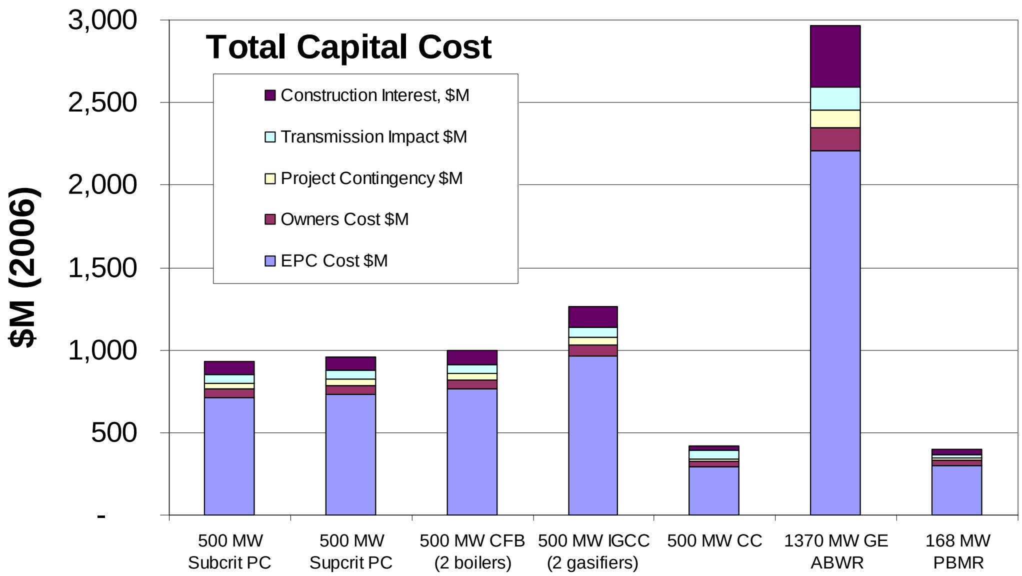
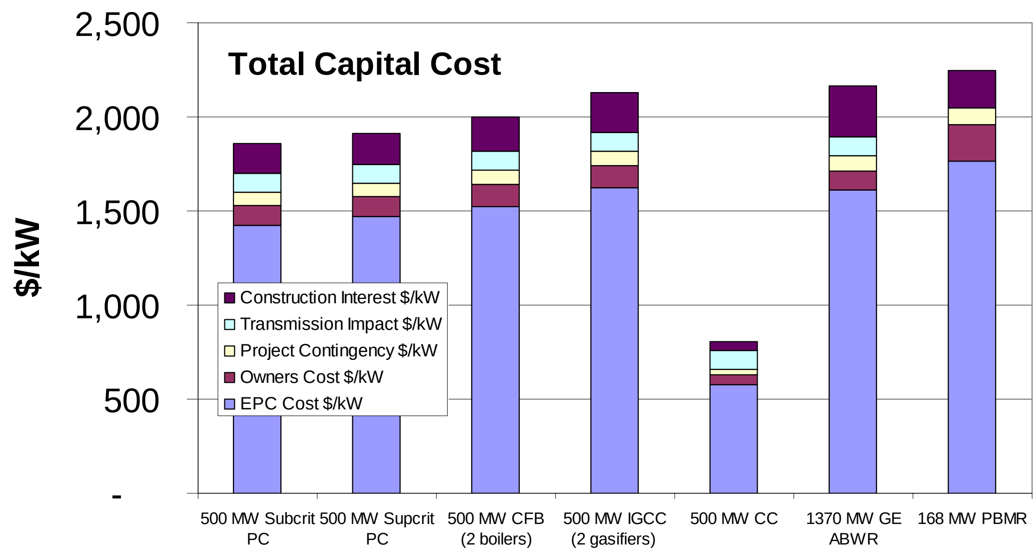


**Figure 2 – Total Capital Investment per kW**




The magnitude of these capital requirements is significant. The conventional 500 MW coal projects require on the order of $1B in financing (note that the CFB has two units that could be staged each with about a $0.5B investment). The 1371 MW nuclear unit requires a total investment of over $3B. A 500 MW combined cyele, and a 168 MW PBMR nuclear module each require only $0.4B.

## Annual Production Costs

Annual first year production costs (2006$) for each plant are shown in Figure 3. Levelized costs in $/MWh are shown in Figure 4.

**Figure 3 – First Year Production Costs**

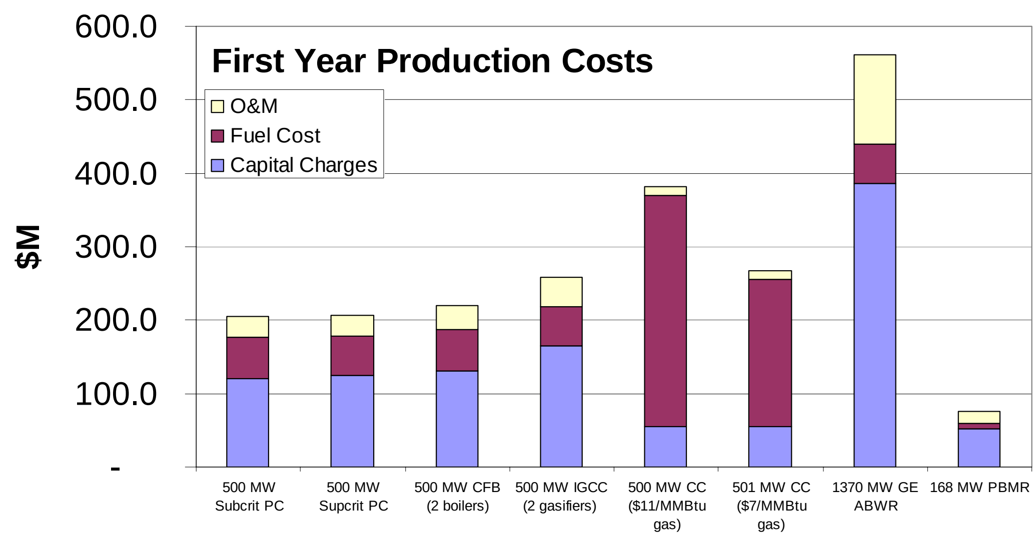
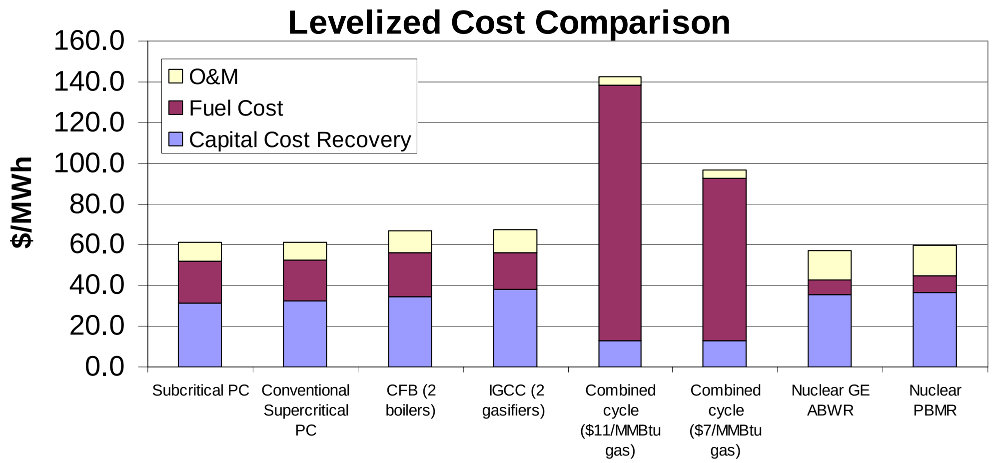


**Figure 4 – Levelized Production Costs**




It is significant to note that the annual cash flows for these projects range from $200M/yr for conventional coal units to $550M/yr for the ABWR. The small 168 MW PBMR module may see a smaller cash flow of less than $100M/yr and a single 250 MW CFB unit would see cash flows slightly higher. The overall levelized costs based on the assumptions in this analysis show that all of the coal and nuclear options are generally competitive on a busbar cost basis. This is due in part to the assumptions used, in that 500MW represents a breakeven point between supercritical and subcritical pulverized coal designs at $1.50/MMBtu coal fuel cost; also this coal price is close to a breakeven value with the nuclear units.

## Economics of $CO_2$ Sequestration

A number of studies have been completed that establish design concepts and preliminary economics for $CO_2$ capture and sequestration that result in a considerable range of costs. The authors have assumed a representative combination of additional capital cost and loss of output resulting in the capital costs shown in Figure 5 and the levelized costs shown in Figure 6. Note that these values are very speculative and are intended only to provide an indication of the relative economics for $CO_2$ capture within various coal plant applications.

**Figure 5 – Capital Costs for PC & IGCC Units Equipped for $CO_2$ Removal & Sequestration**

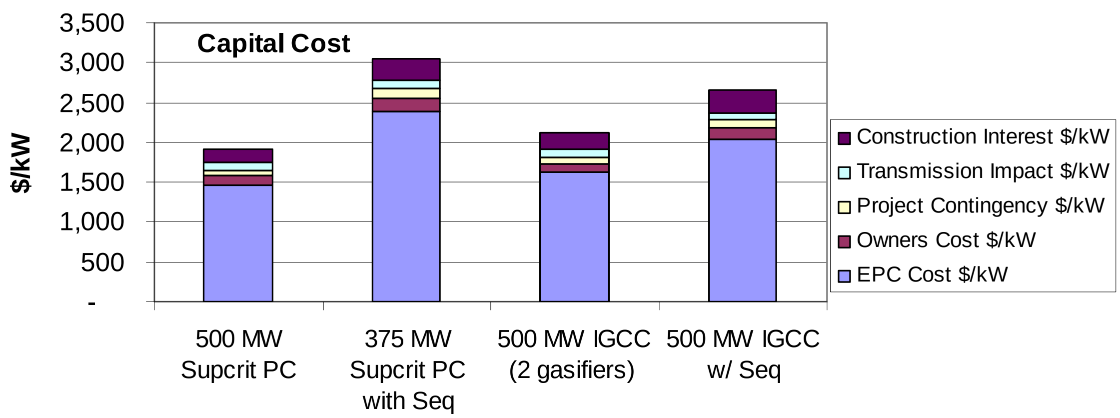
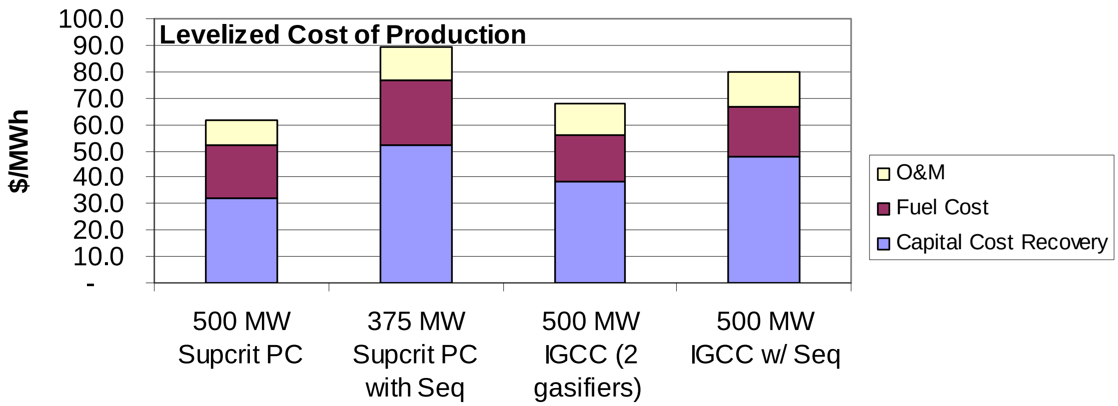


**Figure 6 – Levelized Costs for PC & IGCC Units Equipped for $CO_2$ Removal & Sequestration**




## Changing Risk Profiles

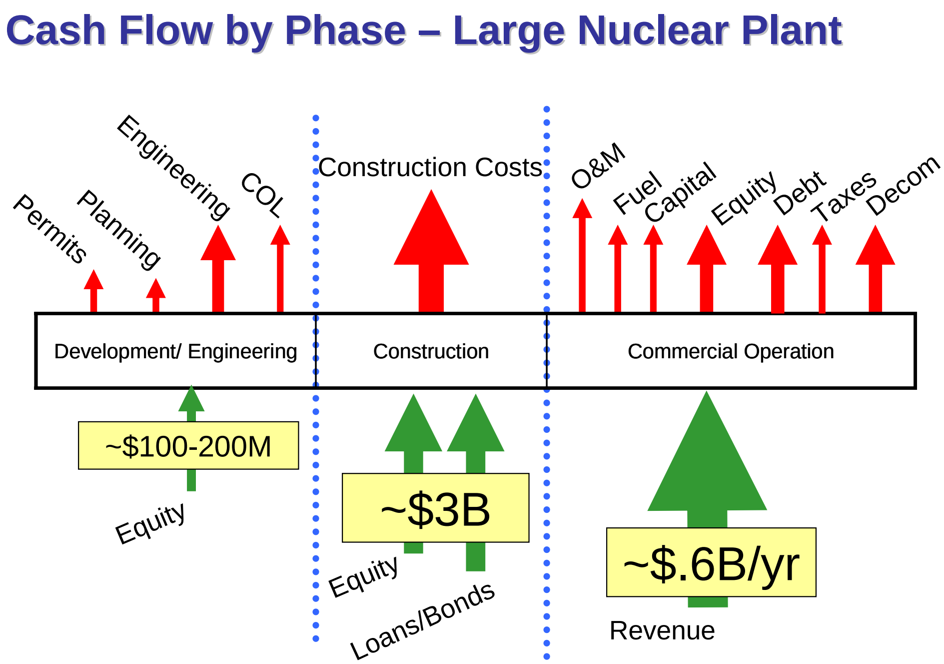
Developers of coal and nuclear projects face dramatically larger risks and more complex project development and financing challenges than associated with the gas-fired combined cycle projects that dominated the market for new plants in the last decade. These include

- More difficult siting constraints
- Long, expensive and riskier project development effort
- More complex environmental permitting and public acceptance issues
- Large grid integration requirements with uncertain cost resolution
- Concentrated construction cash flow and associated risks
- Potentially catastrophic risk consequences by developer, owner, EPC contractor and major equipment suppliers
- Huge operational cash flow sensitivity to quality of design, fabrication and construction
- Translation of major risk taking into substantial increases in pricing and schedule commitments.

Managing these risks becomes more difficult since major equipment suppliers and EPC contractors may be more reluctant to take high liability limits and other contract risks that have cost them huge losses in the past. In the event that strong price and schedule-certain contracts cannot be obtained, which is the normally the case for new technologies, conventional financing is much more difficult to obtain. In such cases innovative contracting schemes will be necessary as well as various forms of government risk-sharing such as provided by the Energy Policy Act for nuclear and advanced coal technologies.

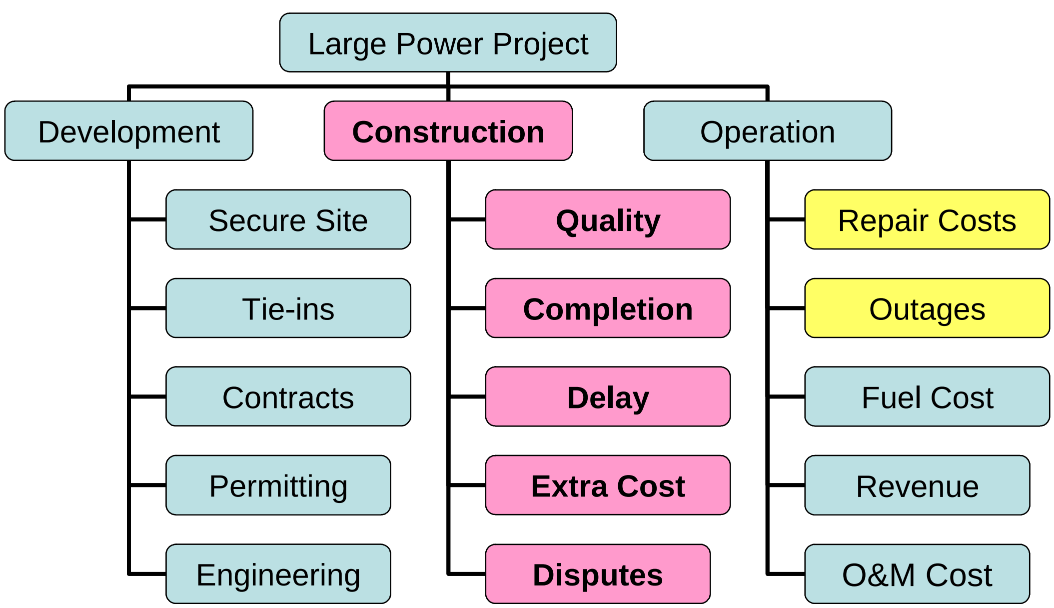
The rough cash flow requirements of a large nuclear plant are illustrated in Figure 7.

**Figure 7 – Cash Flow Requirements for a Nuclear Project**




Some of the most significant areas of project risk are shown in Figure 8.

**Figure 8 – Major Risks by Project Phase**

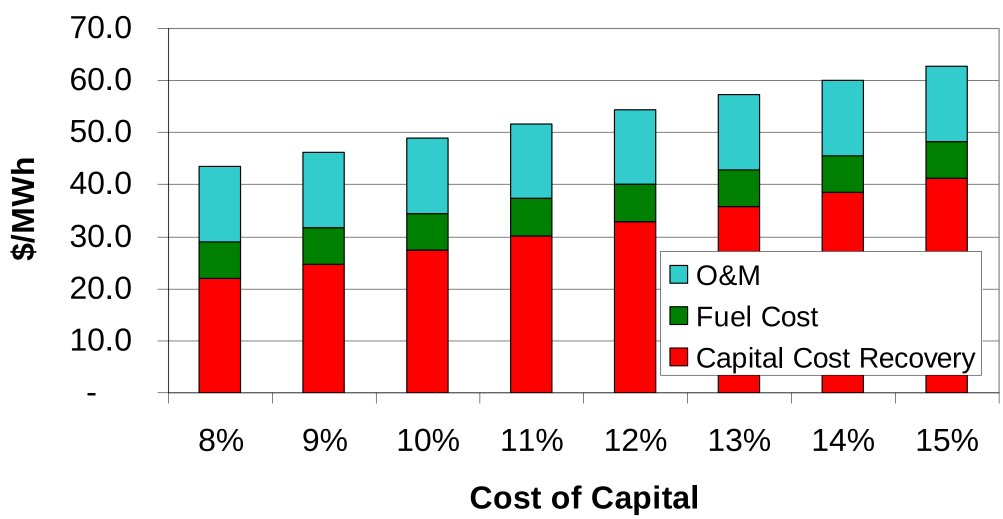


Availability risk, and the risk of project non-completion or early end-of-life, probably represent the largest risks undertaken by developers and owner that are committed to repayment of loans or bonds for the project. Delay risk can approach $0.6-0.7M per day for a $3B financing. For a large nuclear unit, the revenue lost from one day's outage can be on the order of $1.5-2M per day plus the cost of penalties associated with a power sales agreement which can include the cost of replacement capacity and energy.

In general, plant availability is highly sensitive to the quality of design, quality of operations staff, adequacy of funding operations and maintenance, adequacy of continued capital investments to maintain the condition of the plant, satisfactory resolution of regulatory requirements, and the implementation of world class preventive maintenance and outage management programs. Normally, after commercial operation, availability risk is shared by the owner and off-taker based on the terms of power sales agreements that define the level of allowable outages and quantify penalty costs for replacement capacity and energy.

The perception of risk and its mitigation can impact the cost of capital. Figure 9 illustrates the impact that cost of capital has on the levelized cost of the 1371MW nuclear unit.

**Figure 9 – Nuclear Plant Levelized Cost Sensitivity to Cost of Capital**




The assumed 13% cost of capital should be roughly representative of a financing arrangement by a regulated utility which assigns some of the risk and benefits to the stockholders. A cost of capital of 15% or higher can result if private equity is assigned more of the risk, with some support through off-taker agreements. A lower cost of capital can occur through public power bond financings where more of the risks are taken by public bondholders, electric customers and the taxpayer. As shown in the graph, the cost of capital recovery can almost double across this range. This graph dramatizes the cost of risk taking as represented by the required return on investment. The benefits of long term production cost stability can be held by the electric consumer if the project benefits from lower cost public financing. Conversely, if the project risks are shifted to private capital, then the equity owners will benefit from the potential for huge increases in revenue if competing energy prices go up in the future.

Figures 10 and 11 illustrate the major risk-sharing concepts for a project company and a regulated owner, respectively.

**Figure 10 – Project Risk Distribution for a Project Company**

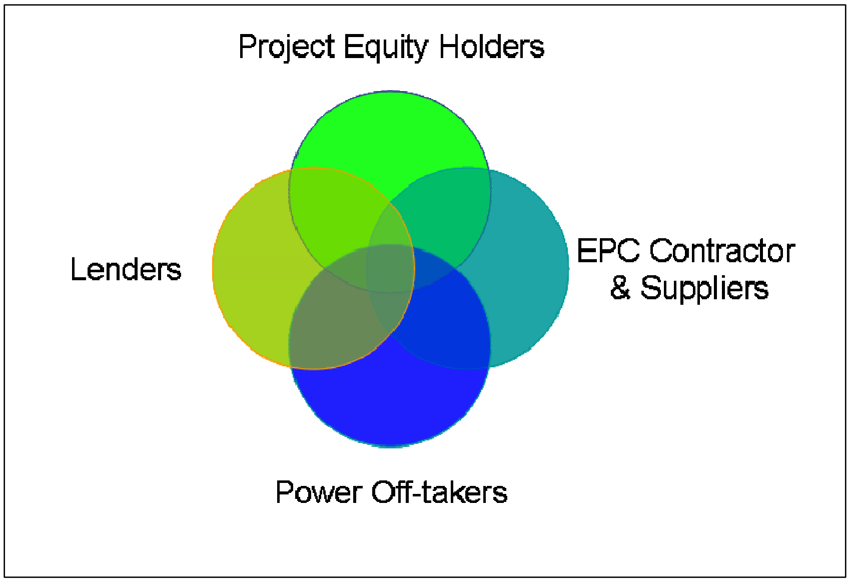
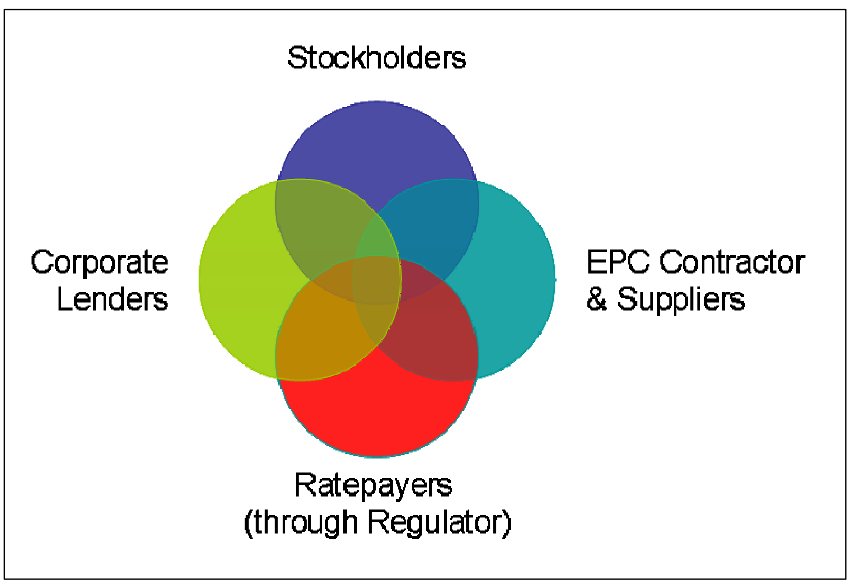



**Figure 11 – Project Risk Distribution for a Regulated Owner**

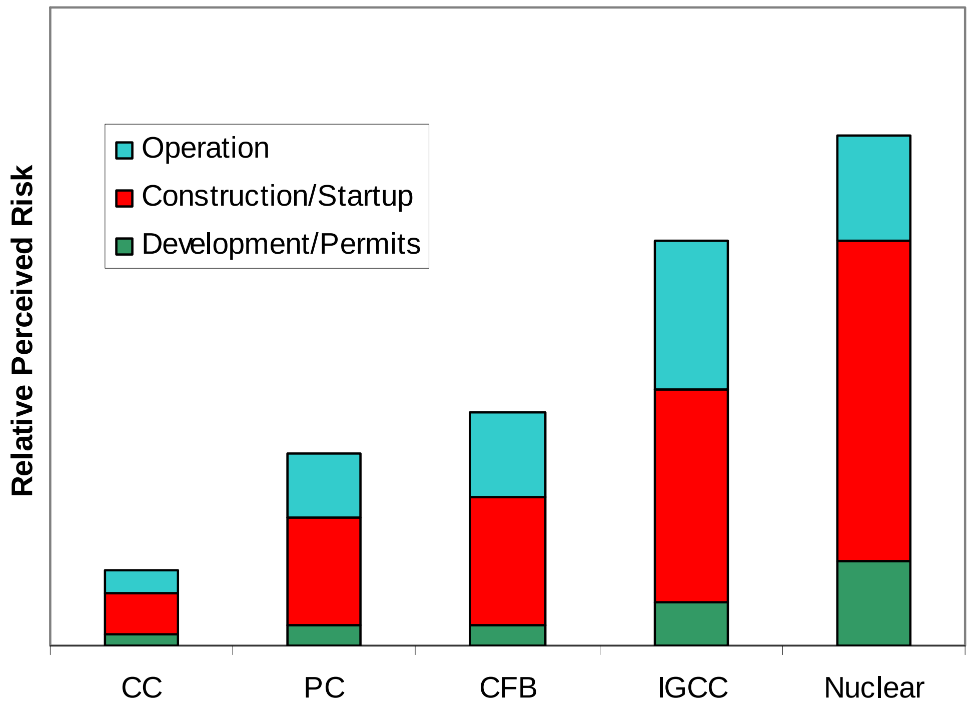



Lenders in either case will look for complete risk coverage by the owner's corporate resources, strength of implementation planning and contracts, and substantial risk-taking by the off-takers or ratepayers. The distribution of major project risks will be determined by the power markets, the valuation of benefits, and the resourcefulness of the developer.

Risk distribution for a regulated utility owner will depend heavily on what is allowed by the state public power regulator. Unless a regulated owner is allowed a higher return on investments in large power generation projects which expose stockholders to significant risk, they may choose to focus investment on lower risk projects, such as transmission and distribution facilities.

Based on the recent experience of the authors in working with financing participants for new projects, Figure 12 illustrates the relative perceived risk by technology. These perceptions are driven primarily by the lack of project experience in the U.S. for the newer technologies and the need for lenders to see some history of successful project implementation.

**Figure 12 – Perceived Risk by Technology**




This graph is subjective and only intends to provide a crude, relative presentation of perceived risk. Based on the magnitude of investments and project cash flows, coal projects are perceived to have more than twice the financial risk during development and construction, and several times the operating risk given their increased technical complexity relative to combined cycle projects. CFB is perceived to have slightly higher risk than PC units due to startup problems encountered in several recent projects, limited experience with larger scale boilers (scale-up risk) and greater variability of fuels and operating conditions. IGCC and nuclear plants obviously present much larger perceived risk until projects are successfully completed to demonstrate acceptable project risk management. Given the extensive successful history of U.S. nuclear fleet operations, there may be more confidence in the ability of new nuclear units to achieve availability targets than IGCC plants which have a very limited history and some projects that have not shown good availability. The interpretation of these perceptions was not based on any formal interviews or surveys, but represents only the impressions of the authors.

### Lessons Learned from Recent Large Power Projects

A number of recent power plant construction projects have run into problems that illustrate some of the key areas of needed risk mitigation during project implementation. Some of the lessons learned from recent projects include:

1. Project equity participation by the major equipment suppliers and EPC contractor have provided additional confidence to lenders, and drives but does not guarantee better project performance. Such arrangements should continue to be beneficial when available.

2. Many recent projects have seen a downturn in the quality of equipment and engineering, impacting plant completion and availability. In some cases it appears that quality control programs have not been effectively implemented at the engineering and factory levels. The owner needs to specify and monitor quality closely, given the huge penalties associated with completion delay and outages.

3. Positive project implementation team working relationships are all-important. Strong contracts with substantial penalties and incentives are important but can drive the project into dispute resolution paths rather than successful project completion. Maintaining contract and working relationships that continue to drive the project toward quality and timely completion are invaluable and deserve substantial resources, especially in the planning phase.

4. The value of reliability continues to appreciate and have growing impact on project economics and risk mitigation needs. Since plant availability is a complex result of design, quality, staffing, budgets, experience, oversight and aggressive planning, it deserves major emphasis in the planning phases of a project.

5. Given exposure to large liabilities on other projects, the financial viability of project participants (equity, contractors, suppliers) can change during the implementation phase of a project. This means that the effectiveness of some contracts and agreements can deteriorate before a project is completed. In many, cases, major participants in a project have changed or been replaced during implementation with some disruptive impacts.

### Other Challenges

Additional challenges affect risk mitigation needs for new projects.

The power industry is experiencing an aging experience base, especially in the coal and nuclear areas where activity in the design of new plants has been very limited in last two decades. This makes it difficult to staff new projects with experienced personnel in project implementation, and much of the experience will have to come from plant operations and maintenance staffing. This is likely to impact the productivity and cost of project engineering, and lead to more conservative schedules and weakened commitments as new project teams develop experience.

Key manufacturing industries (i.e. large vessel fabrication) have limited capacity. This means that certain long lead time items requiring special capabilities, materials and manufacturing facilities may need special arrangements for early release to maintain aggressive implementation schedules.

Environmental and regulatory agencies that haven't dealt much with new plant construction in the last two decades need to rebuild the capability to understand and evaluate permit applications in light of new technologies and designs. This new learning curve can impact the permitting schedules for new projects and introduce additional uncertainty regarding the potential for changing requirements in the future.

A shift toward international sourcing for many plant components introduces dramatic currency risks into project economics. The loss of value by the dollar against the Euro and some other currencies over the last few years has dramatically impacted some equipment costs and contracts, and the prospect of future currency shifts must be addressed in project budgets and agreements so that unexpected shifts can be addressed.

## Risk Mitigation Approaches

Conventional approaches for addressing risk in project implementation planning include the addition of adequate contingencies to project budgets, the negotiation of contracts with appropriate risk sharing measures, the aggressive implementation of Quality Control programs, the selection of a qualified implementation team and suppliers, and the development of a successful plant O&M program. Given the magnitude of the larger projects and exposure to technology risk, the following additional measures are likely to be considered for new MegaProjects:

1. Maximizing off-taker/ratepayer risk sharing during development and construction phases. This can be justified when the off-taker/ratepayers/regulators obtain some or all of the benefits of long term power supply and price stability, as well as environmental benefits of emissions reduction that may or may not be monetized. This means participation by utility regulators and/or wholesale power marketers in the planning and development phases of projects, with some support of the high development costs and construction risks.

2. Since many of the energy security, price stability and environmental benefits accrue to the general public, continued efforts to obtain government support at the federal, state and local levels should be pursued to build on the support offered to date by the Energy Policy Act and state and local initiatives to promote sites considered for some of these new projects.

3. Each of these projects requires a world class implementation team that brings together the best available talent and experience in risk management. This team requires diverse skill sets that include the strongest planning, economics, scheduling, cost estimating, organizational, and contracting skills available in the power industry.

4. Given the concentrated risks encountered during construction, extensive project oversight and innovative construction contracting approaches need to be implemented that provide for risk management by those participants that have greatest control over risk and provide appropriate motivation not only for achieving cost and schedule targets but also regulatory

and quality targets that may impact plant availability during commercial operations. First of a kind projects are likely to implement a combination of collaborative and firm contracting arrangements to optimize the distribution of responsibilities.

5. Given the huge cash flow impact of outages for large single generating units, quality control and startup testing must eliminate residual defects in design, fabrication and construction that can reduce commercial plant revenue.

## Conclusions

The U.S. power market needs many new large plants to replace retiring units, to reduce expensive natural gas consumption, and to achieve emissions reductions. Advanced coal and nuclear technologies promise improved economics and performance for large new plants. However, achieving intended economies-of-scale with large new plants creates major risk management hurdles that include high project development costs, multi-billion dollar financings for construction, and large plant availability risks.

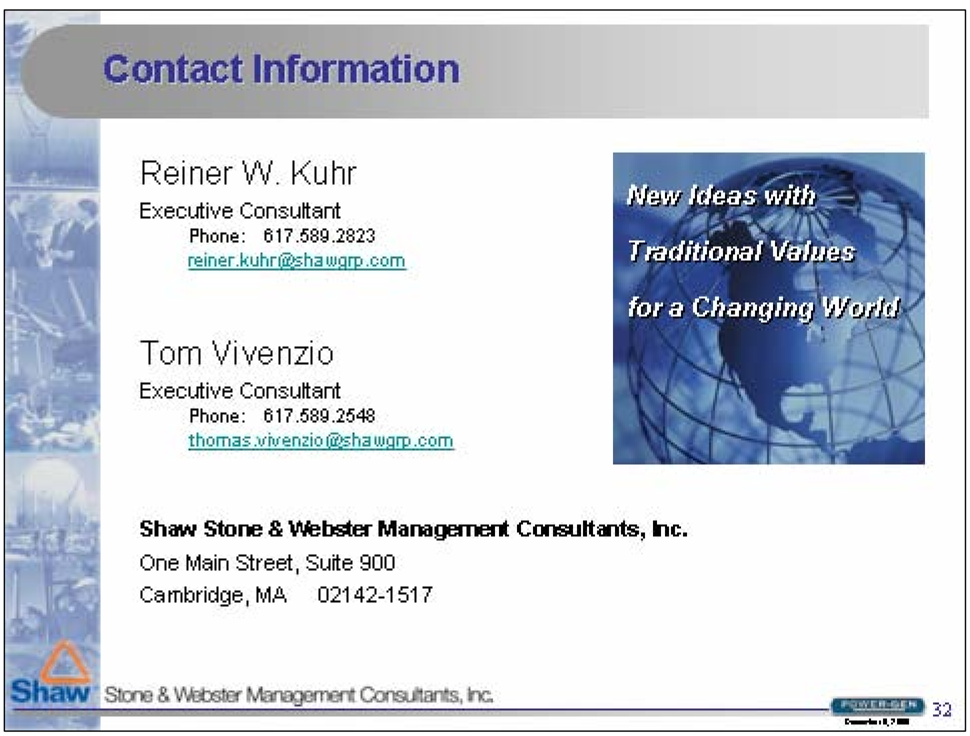
Compared to the recent investment experience in the power industry that dealt primarily with gas-fired combined cycle plants with short construction periods and manageable investment sizes, these risks appear daunting to the financial community as they evaluate the potential for project construction loans and the impact of project commitments on the parent company's balance sheets. Building capacity in smaller increments (like the 168 MW PBMR nuclear modules and 250 MW CFB and IGCC modules) will reduce incremental project risk levels.

In order for a large number of new MegaProjects to proceed, corporate and project lenders will need to see convincing risk management approaches that address the concentration of financial and technical risks. This represents a major challenge to the power industry and will require the best talents and experience available. These project development challenges may not be successful without extended risk-taking by the public (through federal, state and local government), by the ratepayers (through public utility regulation), and by the wholesale power market, which are all beneficiaries of the economic, political, and environmental improvements offered by investing in MegaProjects.

***About the Authors***

Reiner W. Kuhr is an Executive Consultant at Stone & Webster Management Consultants. He has over 33 years of experience in the power and process industries and is a recognized international expert in power generation technology and economics. His experience includes business planning, new technology development, generation planning, plant engineering and design, project management, project cost estimating and economic analysis, project financing and risk management evaluations. He has participated in the review and oversight of over $20 billion in project financings and transactions and was technical advisor to the British Government for the financial restructuring of British Energy. He currently advises several clients in the power industry in business planning, evaluation of new power project opportunities, and oversight of project implementation.

Tom Vivenzio is an Executive Consultant at Stone & Webster Management Consultants with over 35 years experience in the power and process industries. His experience includes power plant engineering, new technology development, and project economic analysis and feasibility studies. He has worked with Mr. Kuhr over the last 10 years to prepare numerous reference power plant designs for new power projects, along with cost and performance models used by several project developers to select the most attractive projects and technologies. He is a recognized expert in advanced coal technologies, including gasification, and has participated in numerous technology assessment and demonstration projects. He has participated in the review and oversight of over $10 billion in project financings and transactions. He currently works with several clients to assist them in the evaluation of alternative plant designs and economics for new power projects.

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