COMMENTS BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION
RE: PG&E Steam Generator Replacement Project Application # 04-01-009

Submitted to:
California Public Utilities Commission
C/o Aspen Environmental Group
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Submitted by:
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Date: October 27, 2004

My comments today will address the scope of the proposed E.I.R for the above captioned project. Others present will no doubt address the specific environmental and economic disinsentives to the proposed project. I would like to draw your attention to the NO PROJECT ALTERNATIVE, particularly those points associated with the categories of:

- Replacement generation facilities (including construction of natural gas-fired plants)
- Combination of replacement transmission and generation

In the 7 pages of supplemental data following this introduction, I present several case studies that should be investigated and analyzed as potential solutions to the NO PROJET ALTERNATIVE.

In summary, the PG&E steam generator replacement is anticipated to cost $706 million or more, and doing so will maintain the service of Diablo Canyon to generate 2 Gw of power. However, that will also mean enhancing the safety and security in an age of potential terrorism, and such safeguards and protections will need to be factored for the additional waste created and stored on site, as it is now apparent that due to recent legal judgements, the creation of a national radioactive waste repository at Yucca Mountain, Nevada, is on hold. In light of this, and the ensuing and yet unanticipated costs, continued generation of nuclear power at Diablo Canyon in not in the best interest of rate payers.

However, just 12 miles north of Diablo Canyon, in the town of Morro Bay, the Duke Energy corporation has been attempting to build a 1.3 Gw natural gas-fired plant, at a cost of approximately $800 million—all private money from Duke (under FERC)—and not ratepayer money. My proposal is that the EIR consider repurposing the Diablo plant for conversion to natural gas and allowing Duke Energy to build the gas-fired steam generators at the Diablo site, use the steam to turn the existing power block turbines and generators at Diablo, and use the existing PG&E transmission grid to distrubute that power.

As I read through the background materials, I will outline both the economic and energy generation incentives inherent in this proposal. I will cite the example of the Midland Cogeneration Venture in Midland, MI (the largest existing re-purposing of a non-active nuclear facility) as well as proposals by PG&E to build a new natural gas facility in Van Buren County, Michigan—concurrent with the decommissioning of the Palisades Nuclear facility. While it is possible to increase the output of a natural gas plant, such as the Midland facility, to 1.5 Gw, the net loss of .5 Gw from Diablo's output could be compensated by using the existing site as a hybrid of solar/wind/tidal power...an experimental multi-mode power production facility. Conservation must also be a part of making up that .5 Gw net loss of power from the decommissioning of Diablo Canyon.

I would also like to draw your attention to the state of Texas, where private industry, with state endorsement, invested nearly $ 1 billion dollars to create 1 Gw of wind power in the hills of west Texas during the late 1990s. I am submitting a video summary of this endeavor on a VHS tape, which is also available as a Quicktime or Real Player video that can be watched on a computer. Please let me know if you request a CD Rom with the computer files for viewing. I am also attaching a 1984 analysis of conversion of nuclear power plants to natural gas.

Morro Bay Power Plant EXECUTIVE SUMMARYTHE MODERNIZATION OF THE MORRO BAY
http://www.duke-energy.com/businesses/plants/own/us/western/morrobay/reports/
app_1a_10_ExecutiveSummary.pdf.

POWER PLANT1.1 INTRODUCTION Duke Energy(1)is pleased to present this Application for Certification (AFC) to the California Energy Commission (Commission) for the modernization of the Morro Bay Power Plant(MBPP). This application proposes to modernize the existing MBPP with a state-of-the-art combustion turbine, combined-cycle electric generating plant that is substantially smaller yet capable of producing more power than the existing facility (Project). With a proposed commercial operation date of the fall 2003, **the Project's 1200 megawatts (MW) of electrical generating capacity will improve California's electrical supply system reliability, help stabilize the state's electricity costs**, and reduce environmental impacts at a critical time when balancing all of these requirements is essential. According to the Morro Bay plant manager, the MBPP "is available for production over 80 percent of the time during peak market months" and that the "existing Morro Bay Power Plant is a reliable and efficient energy producer"(2). **Moreover, the investment that Duke Energy is proposing is made without subsidy from or risk to California's or Morro Bay's ratepayers or taxpayers, precisely the outcome envisioned by California policy makers with the passage of Assembly Bill (AB) 1890, which requires a restructuring of the California energy market and the development and repowering of electric generators at the expense of investor operators**.(3)With thorough and diligent Commission review and approval, this Project's significant benefits to California's electrical system and environmental benefits can be realized by the fall 2003.Through an extensive review by Duke Energy and the City of Morro Bay of how to improve the site, the City of Morro Bay and its residents have fundamentally shaped the specific features of the MBPP modernization effort. In August 1999, Duke Energy had proposed a single 500 MW Project at the MBPP to take the place of Units 1 and 2, with Units 3 and 4 continuing to operate. Through diligent efforts by the City of Morro Bay and Duke Energy, the present Project – the subject of this AFC - is an outstanding example of community planning and participation. Looking beyond the engineering aspects of modernization, Duke Energy and the Morro Bay(1)Duke Energy North America, LLC, a Delaware Limited Liability Company, is referred to throughout this document as "Duke Energy."(2)Plant record from May 1998 to April 2000.(3)Assembly Bill 1890, Electric Industry Restructuring, August 1996.

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Morro Bay Power Plant 1-2 leaders and citizens have created a comprehensive community plan for the power plant site, both modernizing it with the latest high efficiency and environmental friendly technology, as well as fitting it into its surroundings and the larger community. Key benefits of the Project are: Improvements to the Visual Landscape - Duke Energy is addressing visual concerns of the existing power plant with a number of design features for the Project including:-Moving the new lower profile units farther back from the waterfront and Embarcadero.-**Completely demolishing the existing power building and stacks for Units 1 through 4, and the onsite fuel oil tanks in** the near term.-Use of color schemes for the new units and stacks enabling them to blend better with surroundings.-Developing a comprehensive landscape plan for the Project. Improvements to Coastal Access - Duke Energy is Creating bikeways/pedestrian paths along the coast with a bridge across MorroCreek. As part of the Project, Duke Energy is pursuing an option to purchase the "Den Dulk" property which may enable the City of Morro Bay to proceed with aspects of its Waterfront Master Plan. Improvements to the Local Economy - The Project will improve the economy for the City of Morro Bay in a number of ways including a guaranteed revenue stream to stabilize and enhance the City of Morro Bay's budget. Single Construction Phase Modernization - Duke Energy will accelerate the construction of the modernization Project into a single phase, shortening the overall timeline to less than half of the complete replacement project proposed to the City, while achieving all of the benefits sooner. Improving the Environment - Duke Energy is addressing environmental issues by choosing power generation technology that reduces noise, reduces seawater use, reduces cooling water thermal discharge temperatures to Estero Bay, reduces annual emissions of NOxand completely offsets increases in SO2and PM10, protects public health, uses approximately 30 percent less natural gas per MW hour, and further enhances the protection of marine and terrestrial biological resources. Furthermore, with the assistance of the San Luis Obispo County Chumash Council (SLOCCC), the Project provides rigorous and respectful treatment of cultural resources including permanent protection of an existing site.

By Mark Golden

Of DOW JONES NEWSWIRES

SAN FRANCISCO -- On Nov. 15, one of the leases for Duke Energy Corp.'s (DUK) Morro Bay power plant in California expires. If the lease isn't renewed or extended, the plant would have to shut down, though Duke is hopeful that won't happen, the company said Friday. The City of Morro Bay is asking for more money for Duke's use of a tunnel that runs through the city bringing water used to cool the plant to the ocean, said Duke Spokesman Pat Mullen. In addition, **the city wants an assurance that the old plant will be demolished regardless of whether Duke replaces it with a new one, as planned.** Both of those demands are problematic, said Mullen, because the plant is already losing money and the company needs to find long-term customers for the plant's output before it will rebuild it. The city wants an upfront payment of $3.25 million in January and annual payments totaling $1 million a year for use of the tunnel, which is a large increase over the current annual rent. "We're focusing on how to keep the plant economically viable given its age and the current market conditions and regulatory structure. **Like a number of older facilities in the state, Morro Bay hasn't been able to cover its costs because it runs only a few days a year," said Mullen. The California Independent System Operator has designated some older plants as essential for keeping the state's electric system reliable.** Owners of those plants receive monthly capacity payments regardless of whether the power is actually called on, which covers the owners' fixed costs. Owners of plants that don't receive such payments, like Morro Bay, are prohibited from charging much more than their variable costs when they are called on during acute power demand. As a result, such plants lose millions of dollars over the course of the year. For political reasons, owners of those plants have been reluctant to shut down such plants in the wake of the California energy crisis, but their patience is wearing thin, especially since almost all of those companies have been hit upon very tough times financially for two years. The current 50-year lease for the Morro Bay tunnel was signed by the state originally and then consigned to the City of Morro Bay. Mullen said that the plant would have to shut down if a new lease isn't signed or some extension is worked out before Nov. 15, but Duke hopes to avoid that. **"We're looking at all options to secure a contract for output or capacity or any other options that will keep the facility viable.** As far as the lease, we're going to try to work with the city to address their concerns," said Mullen. Duke has a separate permit with the state for the actual discharge of water into the ocean. That permit is on an administrative extension, with a hearing scheduled for December to give Duke a new permit for the rebuilt power plant. On Aug. 3, the California Energy Commission approved Duke's application for the new plant. The 1,000-megawatt, natural gas-fired Morro Bay plant is located about 150 miles north of Los Angeles on the Pacific Coast. The new plant, located further from the shoreline, will be able to produce an additional 200 megawatts while burning less fuel and producing less pollution**. It will cost about $800 million to build. The company is also in negotiations to spend up to $12 million to improve the fish habitat near the plant, but that hasn't been finalized**, Mullen said. Duke wants to sell Morro Bay's output under a long-term contract or contracts with utilities such as PG&E Corp.'s (PCG) Pacific Gas & Electric Co., smaller municipal utilities or large industrial customers in California. Recent actions by the California Public Utilities Commission are pushing the state's utilities into signing such deals. Duke also wants regulatory stability in the state before proceeding with construction. The company first proposed the idea for a new plant to local authorities in the fall of 1998, and the city has supported the project. Duke applied for a permit with the California Energy Commission in October 2000.

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http://www.coastalconservancy.ca.gov/coast&ocean/winter2000/pages/pona.htm
Diablo Canyon:

You cannot see this nuclear power plant from the highway, nor from a trail. PG&E owns 12,000 acres around it, including 14 miles of coastal terrace, extending up to two miles inland. Docent-led hikes, with magnificent coastal views, are offered on the seven-mile-loop Pecho Coast Trail. Otherwise there is no public access. The site PG&E first chose for this plant was in the Nipomo Dunes, but the Sierra Club and others objected. In a move that agonized and split the membership, the Sierra Club suggested the Diablo Canyon site as preferable.

The two units that PG&E planned to open in 1972 and 1974 actually began to operate in 1985 and 1986. The estimated construction cost of $320 million grew to an actual cost of $5.8 billion—over 17 times as much. When at the CPUC, I negotiated the agreement under which ratepayers pay PG&E a price for each kilowatt produced at Diablo Canyon, according to a system called performance-based pricing. Otherwise the CPUC would have had a many-year-long fight over how much of the plant's $5.8 billion cost was "reasonable" for ratepayers to pay for, and how much was "unreasonable," that stockholders would pay. PG&E has operated the plant well above the national average of efficiency and so has come out financially whole under the performance-based pricing formula.

Midland Cogeneration Venture Limited Partnership Company Profile

Midland Cogeneration Venture operates one of the largest cogeneration power plants in the US. The company, with a generating capacity up to 1,500 MW, is jointly owned by CMS Energy (49%), El Paso Merchant Energy (44%), and Dow Chemical (7%).

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Authorization for Importation of **Natural Gas** from Canada
I. Background
On March 31, 1989, the Assistant Secretary of Fossil Energy (FE) of the U.S. Department of Energy (DOE) issued DOE/FE Opinion and Order No. 305 1/ (Order 305) to **Midland** Cogeneration Venture Limited Partnership **Midland**) conditionally authorizing **Midland** to import from four Canadian suppliers up to an aggregate daily contract quantity of 55,000 Mcf of Canadian **natural gas** over a 15-year period beginning on the date of initial firm deliveries. Order 305 granted **Midland** final authority to import up to 51,500 Mcf per day of Canadian **natural gas** on an interruptible basis using existing facilities beginning in 1989 and ending in 1990 on the date of initial firm deliveries. The imported **gas** would be used to fuel a proposed new **cogeneration facility to be constructed in Midland County, Michigan, by conversion of a portion of the idled Midland nuclear plant.** The authority granted to **Midland** to import up to 55,000 Mcf per day of Canadian **natural gas** on a firm basis was conditioned upon completion of the environmental analysis of the impact of the **Midland** project required by the National Environmental Policy Act of 1969 (NEPA).2/ Under the **import proposal**, **Midland** would import Canadian **gas** under **natural gas** purchase agreements with the following four Canadian suppliers: (1) from Norcen Energy Resources Limited, up to 6,500 Mcf per day through November 1, 1994, and thereafter up to 10,000 Mcf per day over a term of 12 years, or through November 1, 2001, whichever is earlier; (2) from Shell Canada Limited, up to 15,000 Mcf per day for 15 years or such earlier date as may be required by U.S. or Canadian regulatory authorities; (1) Canterra Energy Ltd., up to 15,000 Mcf per day through December 31, 2004; and (4) from TransCanada PipeLines Limited, up to 15,000 Mcf per day for 15 years, or such earlier date as may be required by U.S. or Canadian regulatory authorities.

On January 23, 1987, CMS **Midland**, Inc. (CMS or Applicant) of Jackson, **Michigan**, filed an application for certification of a facility as a qualifying cogeneration facility pursuant to section 292.207 of the Commission's regulations. The Applicant filed supplemental information on January 29, February 3, and February 13, 1987. Notice of the application was published in the *Federal Register* on January 30, 1987.
1
The proposed topping-cycle cogeneration facility will be located in Midland, Michigan. The primary energy source of the facility will be natural gas. The proposed facility will use some of the cancelled Midland nuclear plant quipment.
2
The Applicant requests certification of two alternative configurations for the facility. Under the first alternative, the Complete Conversion Alternative (CCA), the facility will consist of twelve combustion turbine-generators (81.5 MW net each), twelve heat recovery steam generators (HRSGs), and an extraction/condensing turbine-generator (365.2 MW net). The total net electric **power** production capacity under the CCA will be 1,343.2 MW. Under the second alternative, the Partial Conversion Alternative (PCA), the facility will consist of eight combustion turbine-generators (81.5 MW net each), eight HRSGs, and an extraction/condensing turbine generator (213.8 MW net). The total net electric **power** production capacity under the PCA will be 865.8 MW. Installation of the facility is scheduled to commence in 1988. Under each alternative, exhaust heat recovered from each combustion turbine-generator will be directed to a normally unfired dual-pressure **natural** circulation HRSG which is capable of supplemental firing.

http://www.msue.msu.edu/vanburen/vbrenaiszone.htm http://www.msue.msu.edu/vanburen/vbrenaiszone.htm

Economy Development

Van Buren County
Renaissance Zone

Renaissance Zones are regions of the state of Michigan set aside as virtually tax-free for any business or resident presently located in or moving to one of the zones and there is no paperwork.

Renaissance Zones are an economic development breakthrough that originated here in Michigan, and are now being copied by other states. In three years, the initial 11 zones have spurred more than $315 million of private investment in 126 projects and creation of 3,612 jobs.

The taxes that companies and residents **do not** pay are nearly all the state and local taxes levied on business activity. They are:

Single Business Tax
State personal income tax
6-mill state education tax
Local personal property tax
Local real property tax
Local income tax
Utility users tax

Taxes still due are those mandated by the federal government or local bond obligations:

Social Security tax
Unemployment compensation
Worker's compensation
Sewer and water fees
Property taxes resulting from local bonded indebtedness or special assessments
State 6 percent sales tax (Michigan does not allow local sales tax)

Best of all, there is no paperwork. Businesses or individuals who move into a zone can just start keeping their tax dollars.

Executive Summary of Development Plan For Van Buren County

The Van Buren County Renaissance Zone Development Plan calls for significant industrial development in depressed areas of Van Buren County, spurred by the designation of six areas as Renaissance Subzones under Michigan law.

Van Buren County and the Four Renaissance Subzone Communities

The four communities have established subzones. They are Covert Township, the City of Bangor, the Village of Bloomingdale and the City of Hartford.

Most of the land within the subzones are currently owned by the local governments, and have no economic activity at the current time. Van Buren County is a ten-year Renaissance Zone designation for six subzones, with total area of 427.9 acres, of which 77% are publicly owned.

Natural Strengths

Van Buren County has certain natural strengths, which this plan capitalizes upon. The county is located in the Southwest portion of the state, close to Lake **Michigan, and has major natural gas pipelines and electrical transmission lines running through it. With the forthcoming decommissioning of its major nuclear power plant in 2007, the region is in significant need of additional power generating.**

PG&E Generating, a major national player in the burgeoning merchant generating field, is considering a major commitment to bringing a $500 million merchant facility to Covert Township. Such a merchant generating facility could use the existing natural gas and electrical transmissions lines, as well as the proximity to Lake Michigan. The new generating facility would support the energy demands of the region and the electrical supply in the State as a whole.

Other subzones included would provide servicing for the construction activity for the plant; industrial park development in depressed areas of Hartford and Bangor, needed medical services, and other economic expansion that would greatly assist the region. These anticipated investments account for an additional $93 million, bringing the total projected direct investments in Van Buren County's Renaissance Zone to $593 million.

Environmental Concerns

The Van Buren County Zone is also notable for its sensitivity to environmental concerns. The merchant generating facility will use existing natural gas pipelines and high voltage electrical transmission lines to provide power to homes and industry in other areas of the state. Rather than locate the plant on Lake Michigan, the company has committed to supporting the construction of a special $16 million water intake channel, which will become the property of the City of South Haven. Thus, when the decommissioning of the Palisades Nuclear Power Plant is completed, no major utility will detract from the scenic Lake Michigan coastline in Van Buren County.

In addition, the combined gas-cycle generator planned for the site runs much cleaner than the predominantly coal-fired generators that fuel much of Michigan's current power needs. As national and international concern about ozone, particulates, and greenhouse gases grows, such clean-burning power generating plants will become important building blocks in our state's economic future.

Economic Development Plan   Goals of the Zone

The primary goal of the Van Buren County Renaissance Zones is to dramatically increase economic activity in these areas. The increased economic activity, particularly through new investment and the employment that supports it, will generate substantial spin-off effects through the servicing, supply, and other supporting economic activity in the remaining areas of Van Buren County, as well as the State of Michigan as a whole.

Strategic Plans for Each Zone

Van Buren County is located in the Southwest corner of the State of Michigan, in an area that is predominantly agricultural. We have developed a strategic plan that capitalizes on the specific strengths and weaknesses of Van Buren County and these communities.

Covert Township

While it contains seriously depressed areas, Van Buren County has significant strengths as well. This area of the county, particularly Covert Township, is located at an important nexus for the energy supply of the State of Michigan. Major natural gas interstate pipelines run through Covert Township, coming up from the south. **At the same time, one of the State's major high-voltage transmission lines runs directly East from Covert Township toward the middle of the state. This transmission line currently transmits the power generated at the Palisades Nuclear Power Plant, located in Covert Township on Lake Michigan. This nuclear power plant will be decommissioned after the year 2007, taking with it a significant chunk of the tax base of the county and the township. The strategic plan for the Covert Township portion of the renaissance zone is to capitalize on this existing energy infrastructure, and create a new merchant generating plant in the township. Such a plant is already under consideration by Covert Generating, a unit of PG&E Generating.** The company anticipates making a $500 million investment in the township. The designation of a renaissance zone provides the necessary tax incentive, allowing the company to make the major investment that will achieve for us this portion of the plan.

The construction of the plant is estimated to take between two and three years, generating substantial jobs and income in Van Buren County. Once the plant becomes operational, the county will benefit from the addition of high-paying jobs within the plant, plus other auxiliary supporting jobs in and around the plant area. In addition, the creation of the generating plant would enable Van Buren County to explore substantial agribusiness possibilities. One possible avenue would be to use the steam produced at the plant to power an ethanol plant. Ethanol production involves the conversion of agriculture products , particularly corn, into a gasoline substitute. The production of ethanol requires great amounts of power and heat, and the merchant generating plant would be a natural partner for such an industry. Should the county be able to develop such a capacity, it would have obvious positive effects on demand for agricultural products throughout Southwestern Michigan, as well as the remainder of the state.

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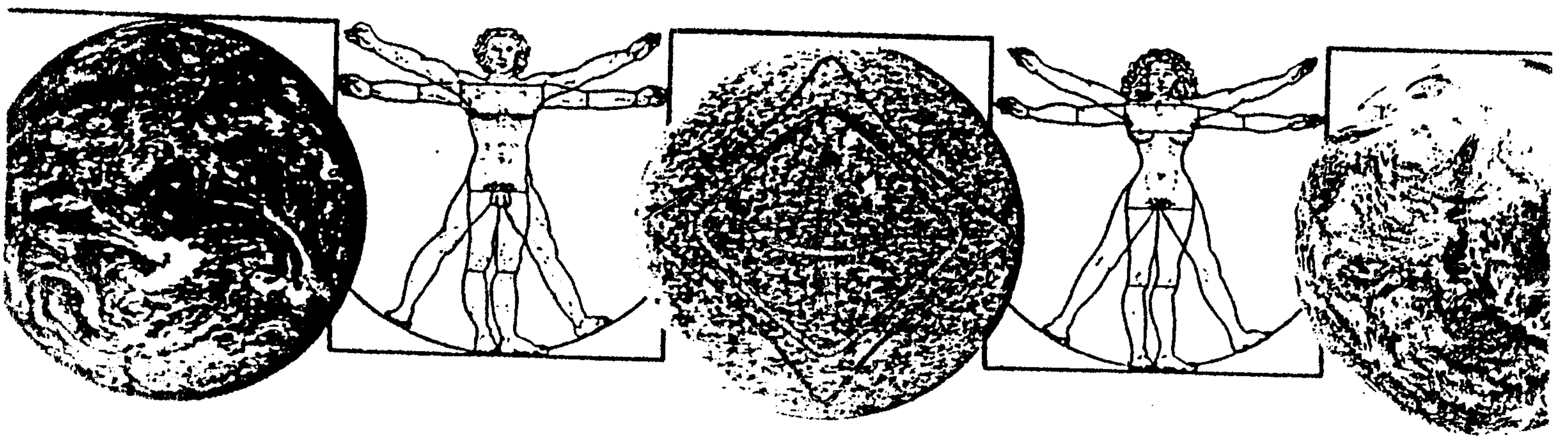

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"Economical Conversion of Unfueled Nuclear Generating Stations"

By Miguel A. Pulido, Jack R. Jennings, Sheldon C. Plotkin, Barbara Masters, and Corey Dxitzer

(The authors are all members of the Southern California Federations of Scientists.)

Economical Conversion of Unfueled Nuclear Generating Stations

MIGUEL A. PULIDO, JACK R. JENNINGS, SHELDON C. PLOTKIN, BARBARA MASTERS, AND COREY DZITZER

INTRODUCTION

A major problem has been confronting electric utilities. Large nuclear power plants are nearing completion at costs many times more than the original estimates. Billions of dollars more are required for actual completion. In the meantime, electricity demand is far below values projected at the time the plants were initiated. What to do?

The purpose of this study is to consider whether or not an already constructed, but not yet contaminated, nuclear power plant can be converted to gas without severe economic penalty. Specifically, must a utility company suffer a several billion dollar loss if the utility abandons nuclear power?

The study focusses on one particular plant, the San Onofre Nuclear Generating Station 2 (SONGS 2). The plant, located near San Clemente, California, was undergoing low-power testing at the time of this study in 1982. While this study used SONGS 2 as a prototype for assessing the economic feasibility of nuclear plant conversion, the conclusions are generally applicable to other nuclear plants at a similar stage of construction.

The study shows that, with reasonable increases in the future costs of natural gas, the cost for conversion and operation of a nuclear plant as a gas-burning facility would be comparable to the cost of its completion and operation as a nuclear plant.

METHODOLOGY

To determine the economics of conversion, this study first considers cost components common to all electric generating plants. Common costs include capital, fuel, and "operation and maintenance." However, the capital cost for a gas-burning plant includes the cost for the conversion process itself. Cost components unique to nuclear plants include fuel subsidies and decommissioning. The main cost unique to plants which burn natural gas is that for the control of airborne pollutants, particularly oxides of nitrogen.

Only costs associated with electricity generation are included. Second-order economic factors, such as profit and the cost of electric transmission are not considered. The study assumes that these factors would apply equally to both nuclear and natural gas plants, and would, therefore, not affect the relative costs of the two options.

Two types of inflation are considered in the study; namely, general inflation, and consumable resource inflation. General inflation is assumed to affect equally both types of electric generating plant. Accordingly, the effect of general inflation is treated by using constant 1981 dollars for each cost component.

Consumable resource inflation is separated from other costs of inflation because both uranium, the fuel for nuclear plants, and natural gas, our alternative fuel choice, are limited resources which become more valuable as reserves are used up. The possibly higher increases in the cost of these diminishing resources result in "added inflation." Unfortunately, there are no firm figures which can be used to determine the "added inflation" rate applicable to either fuel. Appendix A gives estimates of the comparative costs of fuel price inflation different from the general inflation rate. These figures can be used to adjust the final cost comparisons given at the end of the paper to account for fuel price increases or decreases.

All cost factors used in this study are expressed in cents per kilowatt-hour (c/kWh). Each plant will produce a certain amount of useful power which can be estimated accurately. The price consumers must pay for this power reflects total overall costs and is generally expressed on the same basis of c/kWh.

CAPITAL COSTS

SONGS 2

Long term loans are used to finance the capital expenses of nuclear plants; these loans are then paid back with interest, generally over the lifetime of the plant. It is necessary, therefore, to compare interest rates to inflation rates in determining capital costs.

Interest rates on long-term loans are currently very close to the rate of general inflation. This is equivalent to a zero interest rate loan with a zero inflation rate. If interest rates should be greater over the next several years than the general inflation rate, the effect will be the same as that from the combination of an initial increase in capital costs plus no difference between interest and inflation rates. The converse also holds. Interest rates lower than the general inflation rate mean cheaper dollars will be used to pay off the capital investment, so that the effective initial capital investment is decreased. If the difference between inflation and interest were 2% for ex-

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ample, the effective initial capital cost, over thirty years, would be changed by a factor of nearly $(0.02 \times 30/(1 - \exp(-0.02 \times 30))) = 1.3298$. Thus, the difference could be significant.

Without a "crystal ball," there is no way of knowing, a priori, which condition will prevail. However, it seems reasonably safe to conclude that the present long-term interest rate is very nearly what the general inflation rate will be in the future. This means that the present value of those dollars used to pay off the loans for capital investment will be the same as dollars now. Thus, we use current dollar investment as current effective value. In general, if the inflation rate will be less than the interest rate, then the effective capital costs will be larger than we have assumed. Because capital costs in ¢/kWh are larger for the nuclear plant, this factor would bias our study toward the nuclear facility. It is assumed that plant income for capital repayment varies as the general inflation rate.

The SONGS 2 plant will produce 1100 megawatts of electrical power (MWe). The overall capital cost for Southern California Edison (SCE) alone, a 76.55% partner, is currently estimated at \$1.5 billion [1]. Thus, the capital cost of SONG 2 is:

$$\$1.5\ E9/0.7655 = \$1.973\ E9 \tag{1}$$

It is assumed, based on design projections, that the life time of a nuclear power plant is 30 years (and not the approximate 15 years which is the experience to date). It is also assumed that a completed plant operates 52% of the time [2]. Therefore, the capital cost to the rate payer in terms of cost/unit of electrical energy becomes:

$$(\$1.973\ E9 \times 100\ c/\$)/(1100\ MW \times 1000\ kW/MW \times 0.52 \times 30\ yrs \times 8760\ hrs/yr) = 1.31\ c/kWh \tag{2}$$

Converted Facilities

There are additional capital costs associated with equipment and design changes necessary for the natural gas conversion of the partially-constructed nuclear plant. These include the costs for the natural gas burners and the correction for design mismatch between nuclear and natural gas power plant turbines. Nuclear turbines typically operate at a lower temperature and pressure and with larger steam flow rates than do turbines associated with gas-fired boilers.

There are three options for redesigning the turbines:

1. The nuclear plant turbines could be modified by adding several input stages to accommodate higher temperatures and pressures; the power capacity may be kept the same by reducing the quantity of steam flow. This would be the least complicated and least expensive modification.
2. A second steam turbine-alternator could be added that would operate at the higher temperatures and pressures and with the same steam flow rate. This modification would lead to significant capacity increase and appears to be the most cost-effective.
3. A gas turbine alternator set could be added to nearly double the total power capacity by using cogeneration to supply the current steam flow to existing turbines at their required lower pressures and temperatures. When a separate gas turbine/alternator is installed, exhaust gas from the turbine will transfer heat to water which will provide steam for the existing turbo-alternator units.

Since option (3) is the only one for which reasonable cost numbers are available [3], that modification will be used in the calculation of capital costs. Specifically, it is estimated to cost \$85 million to convert the 250 MW Lingen Power Plant in Germany to natural gas [3]. The conversion process would nearly double the power capacity of the plant to 450 MW. For the purposes of this study, we intend to keep the total output of the converted SONGS 2 plant at 1100 MW. Therefore, in determining the cost of conversion, the resultant total output of each plant is used. Assuming a linear relationship, the cost is estimated to be:

$$\$85\ \text{million} \times 1100/450 = \$210\ \text{million} \tag{3}$$

Since these are 1979 figures, they must be adjusted to 1981 prices by the inflation rate which is obtained from the Consumer Price Index for 1979 to 1981.

$$\$210\ \text{million} \times (1.13) \times (1.13) = \$268\ \text{million}$$

where

$$1.13 \times 1.13 = \text{inflation from 1979 to 1981.} \tag{4}$$

Thus, the capital cost of the converted plant will be:

\$1.973 E9 capital cost for SONGS 2
\$0.268 E9 added cost for conversion

\$2.241 E9

The capacity factor, that is, the actual energy generated divided by the rated energy capacity, of this redesigned natural gas power plant will be 0.741 [4]. Note that the comparable value for a nuclear power plant is 0.52 [2]. In addition, the design lifetime of a natural gas plant is 40 years, ten years longer than that for a nuclear plant [16].

Therefore, the capital cost of electricity to the ratepayer becomes:

$$\$2.241\ E9/(1100\ MW \times 0.741 \times 40\ yrs \times 8760\ hrs/yr) = 0.78\ c/kWh$$

Thus, even though the initial investment is greater for the gas-fired plant, the longer lifetime and the larger capacity factor result in a lower unit capital cost, 0.78 c/kWh, than for the nuclear-fired plant, 1.31 c/kWh.

It must be emphasized that both capacity factors are experimental values. Thus, while some large nuclear power plants have operated at somewhat larger fractions of the time, the average is 0.52. This number was obtained by Komanoff by compiling available data and is independent of any engineering judgment. Likewise, the 0.741 gas plant capacity factor is a typical one for Southern California Edison to whom this study was directed. That company's data were more readily available to the authors than those of any other company. Some gas plants have higher capacity values.

As for lifetimes, design values were used in an attempt to be fair to the nuclear plant. While gas plants customarily last at least their 40 year anticipated lifetimes, large nuclear plants have not lasted any longer than 15 years to date. Thus this study has a decided bias toward the nuclear plant. If gas plants customarily lasted 40 years in 1951, they would probably last at least that long today as well.

FUEL COSTS

Nuclear

there are a number of values of nuclear fuel costs in use by the utility companies and it is impossible at this time to determine which is the most valid. SCE projects, for 1982, fuel costs of 0.93 c/kWh [1]. The 1980 fuel cost, also according to SCE, was 0.899 c/kWh. To approximate 1981 fuel costs, the 1980 and the 1982 values were averaged, resulting in a value of 0.915 c/kWh.

For the sake of comparison, Boston-Edison estimated a cost of 1.42 c/kWh by 1991 based upon a 6% inflation rate from 1981 to 1985 and 10% inflation from 1985-1991 [17]. Thus, the 1981 fuel costs

$$1.42 \text{ c/kWh}/(1.06P4 \times 1.10P6) = 0.635 \text{ c/kWh} \quad (7)$$

Thus, the SCE value for fuel costs may be somewhat high.*

Gas

SCE gives 1981 costs for natural gas as $3.60/1000 cu. ft. [5]. In contrast, the California Energy Commission quotes a 1980 natural gas price for Southern California Gas (SCG) of $3.10/1000 cu. ft. (allowing 1000 BTU/cu. ft., [6]. However, SCG lifeline customers were charged $2.66/1000 cu. ft. during July/August of 1981. Since the California Public Utilities Commission claims that no class of service is subsidized by any other class, the $2.66/1000 cu. ft. must be equal to, or greater than, the basic cost [7]. Thus, there is some evidence that the $3.10/1000 cu. ft. is a high cost estimate. Using the same rationale, the $3.60/1000 cu. ft. is probably quite high.

SONGS 2 is owned by two utility companies, SCE and San Diego Gas and Electric (SDGE). SDGE, a 20% owner of San Onofre, purchases gas from SCG at a lower price than does SCE. Thus, the price of gas for a converted nuclear plant could well be lower than $3.60/1000 cu. ft. Nonetheless, for this study, $3.60/1000 cu. ft. was used.

At 1000 BTU/cu. ft. and 10 BTU/Wh, $3.60/1000 cu. ft. easily converts to 3.60 c/kWh.

Added Factors

Because fuel is a nonrenewable resource, its cost will increase faster than the general inflation rate. While it appears that this factor will not be effective in the next 40 or 50 years for either uranium or natural gas, Appendix A specifies how this factor could influence fuel costs.

OPERATION AND MAINTENANCE COSTS (O&M)

Nuclear

SCE data from 1982 indicate that the annual O&M costs for a 1100 MW nuclear plant are $27.76 million [8]. Therefore, the cost per unit of electricity is:

$$\$27.76\text{ E6} \times 100 \text{ c/\$}/(1100 \text{ MW} \times 1000 \text{ kW/MW} \times 0.52 \times 8760 \text{ hrs/yr}) = 0.55 \text{ c/kWh} \quad (8)$$

Gas

To determine the O&M costs for a gas burning plant, the SCE facility in Redondo Beach was used as a guide. O&M for 1980 was approximately $10 E6 [5] for effectively about 960 Mw (the two larger and most efficient turbo generators). Using the same 0.741 SCE capacity factor as before, the cost to the rate payer becomes:

$$\$10\text{ E6} \times 100 \text{ c/\$}/960 \text{ MW} \times 1000 \text{ kW/MW} \times 0.741 \times 8760 \text{ hrs/yr} = 0.16 \text{ c/kWh} \quad (9)$$

These calculated values are consistent with another independent study wherein it was determined that the O&M costs for nuclear power plants are nearly three times those for a natural gas plant [9].

UNIQUE COSTS

Nuclear

There are a number of cost factors for a nuclear power plant which are not applicable to a natural gas power plant. Specifically, these include decommissioning, fuel subsidies, and "crud" cleaning. The last is an insignificant cost and will not be considered further.

Although the NRC contemplates other decommissioning strategies than complete dismantling, e.g. mothballing and entombing [18], it can be shown that the only acceptable strategy is dismantling [10 and 11]. The factors that lead to this conclusion are as follows. Certain long-lived radionuclides produced in the reactor core are extremely toxic and must be kept out of the biosphere essentially forever. There will be about 170 Curies of Nickel-59 (Ni59) in the SONGS 2 core after 30 years, plus even larger quantities of Niobium-94 (Nb94). This is too much radioactivity to be left safely in one location. Ni59 has a half-life of about 80,000 years, while Nb94 has a half-line of nearly 20,000 years. Such half-lives make entombment or simple guarding unacceptable. Dismantling a nuclear reactor costs about 28% more than does the construction of the original plant [14]. For San Onofre, then, the decommissioning cost will be:

$$1.31 \text{ c/kWh} \times 1.28 \times \text{c/kWh} \quad (10)$$

For a more complete discussion of decommissioning, see Appendix B.

At present, nuclear fuel is subsidized in part by the federal government by an amount of 0.1 c/kWh [12]. If the government decides not to subsidize the fuel, then this cost will be passed on to the rate payer. Thus, total added nuclear costs are:

$$1.68 \text{ c/kWh} + 0.1 \text{ c/kWh} = 1.78 \text{ c/kWh} \quad (11)$$

Another unique cost not considered in this study is high level waste disposal. The Federal government has indicated that the cost of nuclear waste disposal will be borne by the entire society using public funds rather than

Editor's note: Since this study was made, gas prices have increased. This would be reflected in a higher per unit power cost for the gas option.

monies collected from the rate payers. Because this condition may change in the future, Appendix C is included to show how a future change in policy might affect the results of this study.

Gas

Reduction of nitrogen oxides can be achieved [13] by an ammonia catalytic technique for a cost of 0.4 c/gal of petroleum or about 0.3% of fuel costs. Applying the same technique to the gas plant exhaust, estimating that it would generally cost the same percentage, results in 0.003 × 6 c/kWh or 0.02 c/kWh being required for NOX reduction.

FINAL COST COMPARISONS

Assuming that general inflation alone is applicable and that interest rates equal inflation rates, component costs are given below.

Component	Nuclear (c/kWh)	Gas (c/kWh)
Capital	1.31	0.78
Fuel	0.92	3.60
O & M	0.55	0.16
Added Unique	1.78	0.02
Totals	4.56	4.56

CONCLUSIONS

Conversion of a nuclear power plant to natural gas before the primary loop has been contaminated with radioactive fission and activation products will probably result in about the same consumer electricity costs over the years. This conclusion derives from assumptions that 1) the fuel cost escalation is not very much above the general inflation rate over the planned 30-year nuclear plant lifetime (Appendix A); 2) the nuclear fuel plant will last the full 30 years as contemplated; 3) the nuclear fuel will be as cheap as originally thought; 4) high-level waste costs will not be included at any later date; and 5) dismantling costs will be no more than computed in this report (Appendix B). Should any of these assumptions prove to be incorrect, the nuclear plant converted to natural gas should be less expensive than the same plant nuclear-fueled.

With respect to natural gas costs, this study used a value somewhat higher than other such cost figures quoted in 1981. It was contemplated that important cost increases would be approximately at the normal inflation rate. However, natural gas has recently doubled in price while normal inflation has only increased about 20%. During this period, significant quantities of new natural gas have been discovered which would normally cause the price to drop. Thus, it may be concluded that the present high cost of natural gas will eventually fall in line with other important plant costs.

It has been argued that the *capacity* factor of 0.741 for a gas plant is merely an *availability* factor representing the possible use of a gas plant, not the actual use. The contention is that, after capital costs have been expended, the actual use of specific plants in a system is dictated by minimizing variable costs, regardless of the fixed costs. *If* there are plants with lower variable costs on a system, they would tend to be used more; hence, it is claimed, our 0.741 capacity factor may not be reached in practice. While there may be some validity to this point in the abstract, one would have to examine each particular utility system to verify the actual use. The 0.741 capacity factor used in this report is the *actual* gas plant utilization factor for Southern California Edison.

APPENDIX A

Fuel Cost Increases Above Those Due to General Inflation

Because fuel might increase in price above the general rate of inflation due to depletion of the fuel resource, an added inflation factor may be required. The table shows the effect of a constant factor over the plant lifetime.

		Fuel Cost with Added Inflation			
f	A	Uranium (c/kWh)	Incr. (c/kWh)	Gas (c/kWh)	Incr. (c/kWh)
0.000	0.000	0.93	0.00	3.60	0.00
0.005	1.08	1.00	0.07	3.87	0.17
0.010	1.16	1.08	0.15	4.18	0.58
0.015	1.25	1.16	0.23	4.50	0.90
0.020	1.35	1.26	0.33	4.86	1.26

f = fuel escalation factor = fuel inflation − general inflation A = ((1 + *f*)P30 − 1)/(30 × *f*) = factor by which fuel costs must be multiplied to represent the effect of "*f*" over 30 years.

APPENDIX B

Nuclear Power Plant Decommissioning Costs

The only acceptable decommissioning technique will be total dismantlement because of Ni59 and Nb94 residue inventories. Hard cost data for such dismantlement are very difficult to find in the literature. To date, no large nuclear power plant has been decommissioned, although Humboldt Bay in California is expected to be decommissioned in the near future.

Published cost numbers have ranged from 100% to 166% of the original capital cost after scaling for the intervening inflation. However, these values are all estimates by their authors or are extrapolated from other estimated data.

The only firm cost figure found was for dismantling the UCLA nuclear reactor [14]. Rockwell, one of the few companies with dismantling experience, proposed a specific cost in 1980 for this project. The total quoted cost was $752K (composed of three separate parts). Original cost for the UCLA reactor in 1958 was $203K. Average inflation according to the Consumer Price Index from 1958 to 1980 was 4.95 %/year. The original cost of the reactor in 1980 dollars would be $203K × 1.0495P22 = $588K.

Thus, the relative cost for decommissioning is:

$752,000/$588,000 = 1.28,

or 128% of initial construction cost for decommissioning after accounting for inflation.

Although the UCLA reactor is a small one, it seems apparent that any relative savings as a result of size would apply equally to both original construction and to dismantling. Thus, the 128% factor is probably as applicable to the dismantling of a large reactor as to the dismantling of the UCLA reactor. This result is also consistent with decommissioning estimates for Humboldt Bay [19] and TMI-2 [20].

It should be mentioned that the Humboldt Bay nuclear Power plant, owned by pacific Gas and Electric, will probably be the first large facility to be decommissioned. However, actual figures for the cost of such decommissioning have not been obtained by PG&E. Their anticipated value as of September, 1983 was about equal to the original capital cost of construction in 1983 dollars. PG&E is very careful to point out that these are only preliminary estimates. Obviously, the fact that dismantling is the only accepted decommissioning technique is reflected in the PG&E estimate. This is also agreed to in the first two papers on decommissioning costs in Ref. [18].

APPENDIX C

High Level Radioactive Waste Disposal

1. A prototype system can never be tested, as good engineering practice dictates, because the test period required would be 1000 years for the high-heat-producing components, Sr90 and Cs137, and 500,000 years for Pu239. The EPA specifies 500,000 years as the required containment interval [15].

2. A disposal site will have to contain at least three barriers; 1) glass on ceramic matrix, 2) steel container and 3) surrounding geological material.

3. Because of 1) above, the disposal vault may have to allow for future retrieval as well as continuous monitoring.

Development of the disposal system will not be charged to rate payers because the identical research and development is required for nuclear weapons waste. However, it may be that the monitoring cost for the waste from each particular plant will be assigned to that plant. Thus, conceivably there could be an added nuclear power cost for the rate payers besides those listed in the body of this study.

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