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Nuclear Power: Outlook for New U.S. Reactors

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Nuclear Power: Outlook for New U.S. Reactors

Summary

Nearly three decades after the most recent order was placed for a new nuclear power plant in the United States, several utilities are now expressing interest in building a total of up to 30 new reactors. The renewed interest in nuclear power has resulted primarily from higher prices for natural gas, improved operation of existing reactors, and uncertainty about future restrictions on coal emissions. A substantial tax credit and other incentives for nuclear generation provided by the Energy Policy Act of 2005 (P.L. 109-58) are also likely to improve the economic viability of qualifying new reactors. New nuclear plant applications can also take advantage of amendments to the Atomic Energy Act made in the early 1990s to reduce licensing delays.

Currently, there are 103 licensed and operable power reactors at 65 plant sites in 31 states, generating about one-fifth of U.S. electricity. Although no new U.S. reactors have started up since 1996, U.S. nuclear electricity generation has since grown by more than 20%. Much of this additional output resulted from reduced downtime, notably through shorter refueling outages. Licensed commercial reactors generated electricity at an average of 89.8% of their total capacity in 2006, after averaging about 75% in the mid-1990s and about 65% in the mid-1980s.

Falling operating costs have helped renew the economic viability of the nation's fleet of nuclear power plants. From 1989 to 1998, 12 commercial reactors were closed before reaching the end of their 40-year licenses. By the late 1990s, there was real doubt that any reactors would make it to 40 years. Since 2000, however, 44 commercial reactors have received 20-year license extensions from the Nuclear Regulatory Commission (NRC), giving them up to 60 years of operation, and more are pending.

The nuclear production tax credit in the Energy Policy Act could have a significant impact on the economic viability of new nuclear power plants. Under base case assumptions, new reactors are not competitive with either coal-fired or natural gas-fired facilities. However, if new reactors are able to take full advantage of the nuclear production tax credit, nuclear power appears competitive with either natural gas-fired or coal-fired facilities.

Other factors will also be important in the commercial decision to invest in new nuclear plants, such as fossil fuel prices and the regulatory environment for both nuclear power and future fossil fuel-fired generation. If natural gas prices remain at historically high levels, future nuclear plants will be more likely to be competitive without federal tax credits. However, natural gas prices have been highly cyclical in the past, raising the possibility that nuclear costs could be undercut in the future.

Any substantial mandatory greenhouse gas control program would probably affect the cost of new coal-fired and natural gas-fired generation relative to nuclear power, particularly if nuclear power is assumed to have no greenhouse gas emissions. Continued delays in nuclear waste disposal facilities — forcing spent fuel to be stored at plant sites — could also affect the decision to construct new reactors.

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Nuclear Power: Outlook for New U.S. Reactors

Introduction

Construction of new nuclear power plants in the United States was almost unimaginable during the 1980s and 1990s. Vague rumors about possible new reactors would occasionally prompt a flurry of speculation, but they were invariably unfounded. In fact, no reactor has been ordered in the United States since 1978, and that plant was later cancelled, as eventually were all U.S. reactor orders after 1973. No U.S. reactor has been completed since 1996 — the Tennessee Valley Authority's Watts Bar 1, which had been ordered in 1970.

Today, there are still no orders, but interest in new U.S. reactors is no longer merely a rumor. In 2003, three utilities submitted applications to the Nuclear Regulatory Commission (NRC) for early approval of potential reactor sites under a cost-shared program with the Department of Energy (DOE). In 2004, DOE announced cost-sharing agreements with two industry consortia to apply for NRC licenses to construct and operate new reactors. Since then, a dozen more utilities and other companies have announced plans to apply for reactor licenses (as shown in **Table 1**), for a total of 34 new nuclear units. Several other companies have announced that they are considering filing applications as well.

The renewed interest in nuclear power has resulted primarily from higher prices for natural gas, improved operation of existing reactors, and uncertainty about future restrictions on coal emissions. Until the recent price volatility, low fuel costs had helped gas-fired power plants dominate the market for new electric generation capacity since the late 1980s. Nuclear power's relatively stable costs and low air emissions may now appear more attractive, particularly combined with a substantial tax credit for nuclear generation and other incentives provided by the Energy Policy Act of 2005 (P.L. 109-58). New nuclear plant applications can also take advantage of amendments to the Atomic Energy Act made in the early 1990s to reduce licensing delays.[1]

In announcing the new reactor license applications, however, utilities have made clear that they are not committed to actually building the reactors, even if the licenses are approved. Large uncertainties about nuclear plant construction costs still remain, along with doubts about progress on nuclear waste disposal and concerns about public opposition. All those problems helped cause the long cessation of U.S. reactor orders and will need to be addressed before financing for new multibillion-dollar nuclear power plants is likely to be obtained.

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[1] Energy Policy Act of 1992, Title XXVIII, P.L. 102-486.

Table 1. Announced Nuclear Plant License Applications

Announced Applicant	Site	Planned Application Date	Reactor Type	Units
Amarillo Power	Not specified	2007	GE ABWR	2
Constellation Energy (Unistar)	Calvert Cliffs (MD)	4Q 2007	Areva EPR	1
	Nine Mile Point (NY)	1st half 2008	Areva EPR	1
	Not specified	4Q 2008	Areva EPR	3
Dominion	North Anna (VA)	Nov. 2007	GE ESBWR	1
DTE Energy	Fermi (MI)	4Q 2008	Not specified	1
Duke Power	Cherokee (SC)	2007-2008	West. AP1000	2
Entergy	River Bend (LA)	May 2008	GE ESBWR	1
Exelon	Texas	Nov. 2008	Not specified	2
FPL	Not specified	2009	Not specified	1
NRG Energy	South Texas Project	2007	GE ABWR	2
NuStart	Grand Gulf (MS)	Nov. 2007	GE ESBWR	1
	Bellefonte (AL)	Oct. 2007	West. AP1000	2
Progress Energy	Harris (NC)	Oct. 2007	West. AP1000	2
	Levy County (FL)	July 2008	West. AP1000	2
SCE&G	Summer (SC)	3Q 2007	West. AP1000	2
Southern	Vogtle (GA)	Mar. 2008	West. AP1000	2
TXU	Comanche Peak (TX)	4Q 2008	Not specified	2
	Texas	4Q 2008	Not specified	2
	Texas	4Q 2008	Not specified	2
Total Units				**34**

Sources: NRC, *Nucleonics Week*, *Nuclear News*, Nuclear Energy Institute, company news releases.

Federal energy policy may play a crucial role in determining whether the current interest in new nuclear reactors leads to a significant expansion of the U.S. nuclear power industry. Nuclear opponents have long maintained that nuclear power will never be economically viable without federal subsidies and should be abandoned in favor of safer alternatives. But supporters contend that nuclear power will be vital in diversifying the nation's future energy supply and reducing greenhouse gas emissions, and that federal subsidies for at least the first few new reactors are justified. The greenhouse gas issue has also prompted some environmentalists to support nuclear power expansion.

This report includes analyses of the potential effect of the tax credit for nuclear power provided by the Energy Policy Act of 2005 and possible competitive effects of various proposals to limit greenhouse gas emissions. Under baseline assumptions, the cost of electricity from new nuclear power plants is likely to be higher than power generated by new coal- and natural gas-fired plants. The new nuclear tax credit would more than offset that cost disadvantage, but it is limited to the first 6,000 megawatts of new nuclear generating capacity. That is the capacity of about four to six reactors, although the credits could be spread among a larger number of new reactors under current rules. If the tax credit results in new reactor construction, the next question will be whether nuclear construction would continue without further credits. Greenhouse gas legislation could also be an important factor in nuclear power economics; analysis shows that some proposals, if enacted, could push the cost of coal- and natural gas-fired electricity above projected nuclear costs.

Current Status of U.S. Nuclear Industry

After the apparently successful commercialization of nuclear power in the 1960s, the Atomic Energy Commission anticipated that more than 1,000 reactors would be operating in the United States by the year 2000.[2] But by the end of the 1970s, it had become clear that nuclear power would not grow nearly that dramatically, and more than 120 reactor orders were ultimately cancelled. Currently, 103 licensed power reactors operate at 65 plant sites in 31 states (not including the Tennessee Valley Authority's [TVA's] Browns Ferry 1, which has not operated since 1985; TVA is spending about $1.8 billion to restart the reactor by mid-2007).

Despite falling short of those early expectations, however, U.S. nuclear power production has grown steadily since its inception and now exceeds electricity generated from oil, natural gas, and hydro plants, and trails only coal, which accounts for more than half of U.S. electricity generation. Nuclear plants generate more than half the electricity in six states. The near-record 823 billion kilowatt-hours of nuclear electricity generated in the United States during 2006[3] was more than the nation's entire electrical output in the early 1960s, when the first large-scale commercial reactors were being ordered, and more than twice the 2005 total electrical generation of Great Britain.[4]

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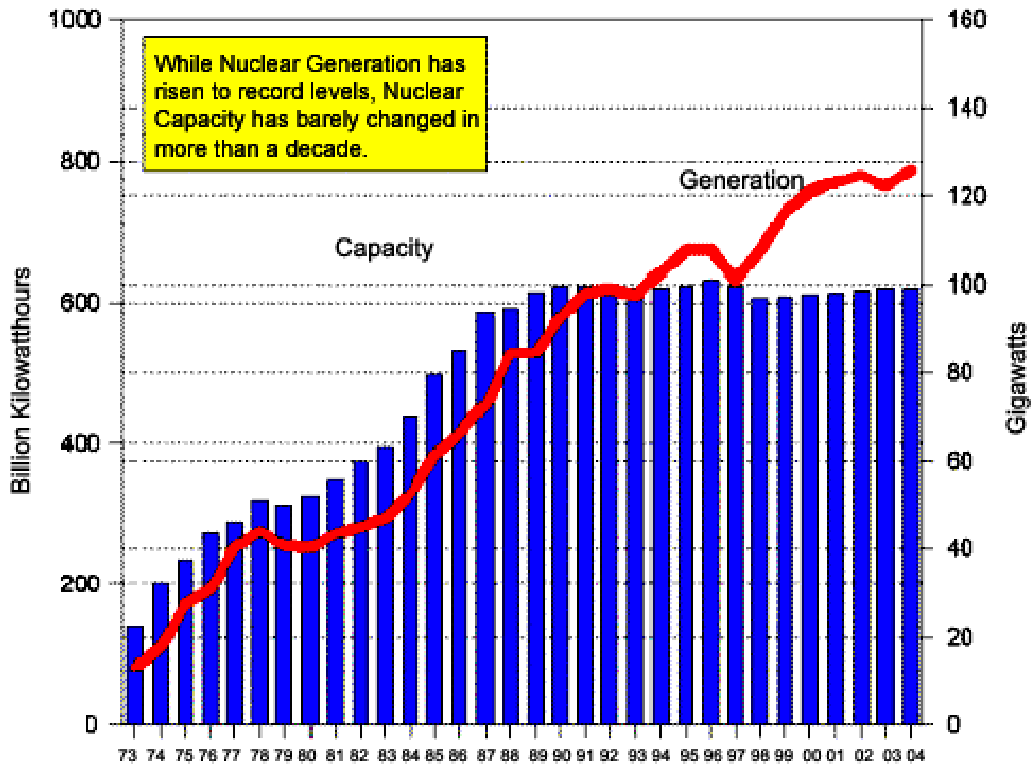
[2] Seaborg, Glenn T., *The Plutonium Economy of the Future*, October 5, 1970, p. 7.

[3] "World Nuclear Generation Sets Record in 2006," *Nucleonics Week*, February 15, 2007, p. 1.

[4] International Energy Agency, *Monthly Electricity Survey*, January 2006.

As indicated in **Figure 1**, although no new U.S. reactors have started up since 1996, U.S. nuclear electricity generation has since grown by more than 20%.[5] Much of this additional output resulted from reduced downtime, notably through shorter refueling outages, which typically take place every 18 months. Licensed commercial reactors generated electricity at an average of 89.8% of their total capacity in 2006, after averaging around 75% in the mid-1990s and around 65% in the mid-1980s.[6] Reactor modifications to boost capacity have also been a factor in the continued

Figure 1. Net Nuclear Generation vs. Capacity, 1973-2004



Source: Energy Information Administration.

Note: Generation is read on the left scale (in billion kilowatt-hours) and capacity (in gigawatts) is on the right.

growth of nuclear power production. Since 1996, NRC has approved more than 60 requests for power uprates, totaling about 2,500 megawatts of electrical generating capacity — about the capacity of two large reactors.[7] The uprates largely offset the

[5] Energy Information Administration, *International Energy Annual 2003*, Table 2.7; *Nucleonics Week*, *op. cit*.

[6] *Nucleonics Week, op. cit.*; *Nuclear Engineering International*, November 2005, p. 37.

[7] Nuclear Regulatory Commission, *Power Uprates for Nuclear Plants*, Fact Sheet, July 2004.

closure of five poorly performing reactors, totaling 3,700 megawatts of capacity, in 1997 and 1998.[8] Further uprate requests are pending.

The improved operation of nuclear power plants has helped drive down the cost of nuclear-generated electricity. Average operations and maintenance costs (including fuel but excluding capital costs) dropped steadily from a high of about 3.5 cents/kilowatt-hour (kwh) in 1987 to below 2 cents/kwh in 2001 (in 2001 dollars).[9] By 2005, the average operating cost was 1.7 cents/kwh.[10]

Falling operating costs have improved the outlook for the nation's existing fleet of nuclear power plants. From 1989 to 1998, 12 commercial reactors were closed before reaching the end of their 40-year licenses — California's Rancho Seco plant and Oregon's Trojan plant after only 14 and 16 years of operation, respectively.[11] By the late 1990s, there was real doubt about whether any reactors would make it to 40 years. Since 2000, however, 48 commercial reactors have received 20-year license extensions from NRC, giving them up to 60 years of operation. License extensions for seven more reactors are currently under review, and many others are anticipated, according to NRC.[12] The license extension trend has been spurred partly by favorable rate treatment of nuclear plants' unrecovered capital costs ("stranded costs") in states that have deregulated the power generation sector.

Industry consolidation could also help existing nuclear power plants, as larger nuclear operators purchase plants from utilities that run only one or two reactors. Several such sales have occurred, including the March 2001 sale of the Millstone plant in Connecticut to Dominion Energy for a record $1.28 billion. The merger of two of the nation's largest nuclear utilities, PECO Energy and Unicom, completed in October 2000, consolidated the operation of 17 reactors under a single corporate entity, Exelon Corporation, headquartered in Chicago.

Although no new U.S. nuclear power plant has opened in the past 10 years, commercial reactor construction has continued elsewhere in the world, particularly in Asia. Since the most recent U.S. reactor began operating in 1996, 37 have started up in other countries, an average of about four per year.[13] Twenty-five reactors are currently under construction outside the United States.[14]

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[8] *Nuclear News*, "World List of Nuclear Power Plants," March 2005, p. 59.

[9] Uranium Information Centre, *The Economics of Nuclear Power*, Briefing Paper 8, January 2006, p. 3.

[10] *Nucleonics Week*, "U.S. Utility Operating Costs, 2005," September 14, 2006, p. 7.

[11] *Nuclear News*, *op. cit*.

[12] See [http://www.nrc.gov/reactors/operating/licensing/renewal/applications.html]

[13] *Nuclear News*, "Word List of Nuclear Power Plants," March 2006, p. 37.

[14] World Nuclear Association, *World Nuclear Power Reactors 2005-06 and Uranium Requirements*, September 21, 2006. Excludes three reactors undergoing reconstruction in the United States and Canada.

Federal Initiatives To Encourage New Nuclear Power Plant Construction

With the Energy Policy Act of 2005, the federal government has adopted aggressive incentives for building new reactors — including tax credits, loan guarantees, and compensation for regulatory delays. These incentives build on previous regulatory and legislative initiatives, particularly a more streamlined NRC licensing process and DOE's Nuclear Power 2010 program to test that process.

NRC Licensing Reform

Until 1989, licensing a new nuclear power facility involved a two-step process: (1) an NRC-issued construction permit that allowed an applicant to begin building a facility and (2) an operating license that permitted the facility to generate electricity for sale.[15] This procedure resulted in some celebrated cases in which completed or nearly completed plants awaited years to be granted operating licenses — delays that drove up the costs of the affected plants. In 1989, NRC issued regulations to streamline this process in three ways:[16]

- The Early Site Permit Program allows utilities to get their proposed reactor sites approved by the NRC before a decision is made on whether or not to build the plant. These preapproved sites can be "banked" for future use.

- Standard Design Certification for advanced reactor designs allows vendors to get their designs approved by NRC for use in the United States, so utilities can then deploy them essentially "off the shelf."

- The Combined Construction and Operating License (COL) provides a "one-step" approval process, in which all licensing hearings for a proposed plant are expected to be conducted before construction begins. The COL would then allow a completed plant to operate if inspections, tests, analyses, and acceptance criteria (ITAAC) were met. This is intended to reduce the chances for regulatory delays after a plant is completed.[17]

The relationships among these three components are illustrated in **Figure 2**. A COL application could reference a preapproved site and a certified plant design, so that most siting and design issues would not need to be revisited. Upon completion, the reactor could begin operating after NRC determined that the ITAAC had been met. The overall goal of these reforms was to introduce as much regulatory certainty into the process before a company has to make a major financial investment in a

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[15] 10 CFR Part 50.

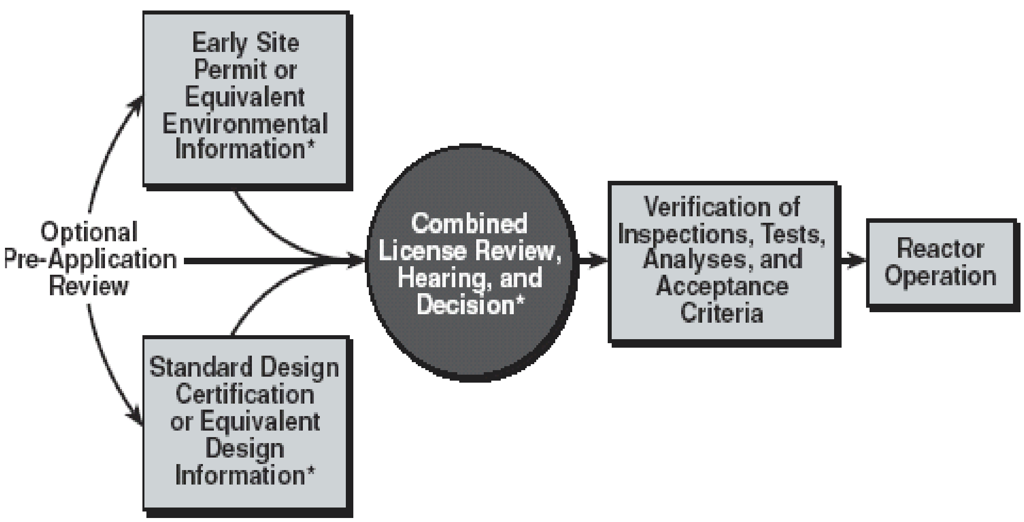
[16] 54 *Federal Register* 15372, Apr. 18, 1989.

[17] After the combined license regulations were challenged in court, Congress endorsed the procedure in the Energy Policy Act of 1992 (P.L. 102-486), Title XXVIII.

project. However, the process has never been used, so it remains uncertain how much time will be saved by referencing preapproved sites and certified designs, or how difficult the ITAAC checkoff process might be.

The procedures envision a three-step decision-making process, allowing the utility to make "go/no-go" decisions at several points before a major investment is made in the project. The first step to building a new facility is to conduct utility level project analysis, including needs assessment, environmental impact scoping analysis, and identification of siting issues. This is anticipated to take about 2-4 years, and some utilities have already begun this process (see **Table 1**). Assuming the utility finds nuclear power to be a viable option, it will have to address three issues in this pre-application process. First, the utility will have to evaluate safety-related issues, such as seismic and geologic data, population demographics, and potential consequences of hypothetical accidents. Second, the utility will have to evaluate environmental issues, such as maximum radiological and thermal effluents. Third, the utility will have to address emergency planning issues, such as evacuation routes. The utility may use the NRC early site permit process to conduct this evaluation but is not required to do so.

Figure 2. Relationship Between Combined Licenses, Early Site Permits, and Standard Design Certifications



*A combined license application can reference an early site permit, a standard design certification, both, or neither. If an application does not reference an early site permit and/or a standard design certification, the applicant must provide an equivalent level of information in the combined license application.

Source: NRC.

Assuming the utility finds the site suitable and the project potentially economical, it submits the above information, along with further details, to the NRC to obtain a COL. This additional information includes financial data, justification for the capacity addition, and complete details on reactor design. On this last point, the utility is likely to reference a standard design certification but is not required to do so. The utility must also provide the ITAAC for the eventual NRC approval to operate the plant. The NRC reviews the application, holds hearings, and makes a decision on granting the COL.

The licensing process is currently estimated by NRC to take about three and a half years, although NRC Chairman Dale Klein has called for that schedule to be shortened.[18] NRC established the Office of New Reactors in 2007 to handle the potential influx of new reactor license applications.

After the license is issued, the utility must decide whether to begin building the power plant. Current projections of nuclear power construction schedules assume that a plant can be built in 5-7 years. At the end of construction, the NRC verifies that the new plant meets the ITAAC in the COL and the facility is allowed to operate. Overall, the process is anticipated to take 10-15 years.

If this streamlined process works as intended, it may remove some of the previous regulatory uncertainty surrounding new nuclear plant construction and make financing of such projects more feasible. This is particularly true for the roughly half of the states that have restructured their electricity markets, thus resulting in utilities employing project financing rather than more traditional funding. With project financing, the proposed developer of a power plant seeks financing for the project using only the project as recourse for the loan, as opposed to securing the loan with the larger holdings of the utility itself. With the project being the only collateral, Wall Street looks very closely at the risk profile of the project in determining whether to finance it and on what terms. The nuclear industry and the NRC hope that the new licensing process will help improve the risk profile of new facilities by increasing the certainty that a plant will be built expeditiously and begin operations in a timely manner. It is also possible that an increase in nuclear power plant permit applications could make the new process more routine, shortening approval time (as has happened with licensing renewal requests for existing facilities, which are now generally approved in about 18 months).

However, there are several reasons to believe that the longer end of the 10-15 year range is more likely, at least in the short-term. First, this is an untried process, as noted above. Uncertainties include some time-honored ones, such as the environmental impact statement and safety evaluation report, as well as new issues presented by the new procedures, such as NRC's certification of a utility's ITAAC. Second, public input is likely to be vigorous. Initial efforts by utilities to obtain early site permits have been slowed by substantial public comments on each permit request. Third, the new procedures do not prevent state intervention into the process, particularly where traditional rate-making authority remains. States can be very resourceful in delaying nuclear power when they so choose. The classic example is the Shoreham nuclear power station, which was completed and licensed but never began commercial operation because of the sustained opposition from the state of New York.

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[18] Weil, Jenny, "Safety of Existing Fleet to Remain the Top Priority at NRC, Klein Says," *Inside NRC*, September 4, 2006, p. 1.

Finally, judicial intervention is not unusual when opposition interest groups attack permits, environmental impact statements, and other regulatory decisions in attempts to forestall construction and operation. When existing nuclear plants were licensed, opposition often focused on the potential for reactor accidents. In the post-9/11 environment, concerns about terrorist attacks are likely to be raised as well.[19]

DOE Nuclear Power 2010 Program

Because no early site permits or COLs had ever been sought, DOE in 2002 initiated the Nuclear Power 2010 Program to demonstrate those processes, offering to pay up to half the licensing costs incurred by industry applicants. The program's original goal was to pave the way for deployment of at least one new nuclear power plant by 2010 and thus reduce regulatory uncertainty for further license applicants.

Although the program's original goal of deploying a reactor by 2010 will not be achieved, industry interest in the effort has been substantial. Under the program, three utilities applied to NRC in 2003 for early site permits to build new reactors at existing plants in Illinois, Mississippi, and Virginia. NRC approved the Illinois permit March 8, 2007, and anticipates final action on the others later this year.[20]

Two industry consortia will continue to receive DOE assistance over the next several years to apply for COLs and conduct "first of a kind engineering" for new nuclear power plants, although they have not committed to ordering the reactors if the licenses are issued. DOE awarded the first funding to the consortia in 2004. DOE assistance under the program, including the early site permits, is planned to reach a multiyear total of about $550 million. The two consortia receiving COL assistance under the Nuclear Power 2010 program are

- A consortium led by Dominion Resources that is preparing a COL for an advanced General Electric reactor (after originally considering a Canadian design). The proposed reactor would be located at Dominion's existing North Anna plant in Virginia, where the company is seeking an NRC early site permit with DOE assistance.

- A consortium called NuStart Energy Development, which includes Exelon and several other major nuclear utilities. The consortium announced on September 22, 2005, that it would seek a COL for a Westinghouse design at the site of TVA's uncompleted Bellefonte nuclear plant in Alabama and for a General Electric design at the Grand Gulf plant in Mississippi.

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[19] For more information on nuclear plant security, see CRS Report RS21131, *Nuclear Power Plants: Vulnerability to Terrorist Attack*, by Mark Holt and Anthony Andrews.

[20] See [http://www.nrc.gov/reactors/new-licensing/esp.html].

Energy Policy Act of 2005

Nuclear Production Tax Credit. The most direct nuclear incentive provided by the Energy Policy Act is a 1.8 cents/kwh tax credit for up to 6,000 megawatts of new nuclear capacity for the first eight years of operation, up to $125 million annually per 1,000 megawatts. An eligible reactor must be placed into service before January 1, 2021. As discussed below, this credit is expected to significantly improve the projected economic viability of proposed nuclear power plants.

A major factor in determining the potential impact of the nuclear production credit is the allocation of the credit among eligible reactors. Under the Energy Policy Act, the 6,000 megawatts of capacity that could receive the credit is to be allocated by the Secretary of the Treasury in consultation with the Secretary of Energy. The Internal Revenue Service issued interim guidance on May 1, 2006, that would provide the tax credit to electricity generated by any reactor that (1) applied for an NRC combined license by December 31, 2008; (2) began construction before January 1, 2014; and (3) was certified by DOE as meeting eligibility requirements.[21]

Under the guidance, if license applications with more than 6,000 megawatts of eligible nuclear capacity are received by December 31, 2008, the 6,000-megawatt cap will be allocated proportionally among the eligible plants. Therefore, if 12,000 megawatts of new nuclear capacity met the application deadline and eventually went into operation, then only half the electrical output of each reactor would get the tax credit. If license applications by December 31, 2008, totaled less than 6,000 megawatts, then additional reactors would become eligible until the limit is reached, according to the IRS guidance.

The deadline for automatic eligibility for the tax credit appears to provide a strong incentive for nuclear plant applicants to file with NRC by the end of 2008, which is sooner than some of the anticipated filings shown in **Table 1**. However, if most of those reactors were to become eligible for the credit, the credit's effect could be diluted to the point where it would no longer provide a sufficient construction incentive.

The credit would most dramatically affect nuclear plant economics if 100% of a reactor's output were eligible; however, if each new nuclear unit were to receive the credit for all its electrical generation, then only four or five reactors (ranging from 1,200-1,500 megawatts) could be covered within the 6,000-megawatt limit. Because reactor designs from three different companies are currently under consideration, only one or two units of each design might be constructed under this scenario. That might not be enough to reduce costs through series production to the point where further units — ineligible for tax credits — would be economically viable on their own.

Regulatory Risk Insurance. Continuing concern over potential regulatory delays, despite the streamlined licensing system now available, prompted Congress

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[21] *Internal Revenue Bulletin*, No. 2006-18, May 1, 2006, p. 855.

to include an insurance system in EPACT that would cover some of the costs of such delays. The regulatory delay insurance, called "Standby Support," would cover the principal and interest on debt and extra costs incurred in purchasing replacement power because of licensing delays. The first two new reactors licensed by NRC that meet other criteria established by DOE could be reimbursed for all such costs, up to $500 million apiece, whereas each of the next four newly licensed reactors could receive 50% reimbursement of up to $250 million.

DOE issued the final rule for the Standby Support program on August 11, 2006.[22] Criteria established by the rule for receiving coverage under the program include the issuance of a COL, a detailed construction schedule, documentation that construction has started, and a detailed schedule for completing the inspections, tests, analyses, and acceptance criteria required for reactor operation to begin. The first two reactors to meet all the criteria would receive the $500 million coverage.

Coverage is to be provided for delays caused by NRC's failure to follow its own rules (if any) in reviewing a reactor's ITAAC, NRC's failure to meet DOE-approved ITAAC schedules, NRC pre-operational hearings, and litigation. Standby Support coverage is not provided for delays caused by "failure of the sponsor to take any action required by law, regulation, or ordinance."[23] This includes delays caused by NRC orders to re-conduct ITAAC or to correct pre-operational deficiencies found by NRC. However, the program does cover delays caused by licensing-related litigation in state, federal, or tribal courts, even if a court rules against a nuclear plant sponsor.[24]

The Standby Support program is intended to reduce uncertainty about the COL licensing process that may pose an obstacle to nuclear plant orders. Because the first two reactors would presumably face the most uncertainty about the untried process, they would receive the most coverage. It is apparently hoped that the licensing experience of the first two reactors would provide enough confidence for the next four to proceed with half the coverage, and then for additional reactors to be built with no regulatory risk insurance.

Loan Guarantees. New nuclear power plants are eligible for federal loan guarantees authorized by EPACT for energy projects that reduce air emissions, a criterion that includes new clean coal projects. The loan guarantees may cover up to 80% of a plant's estimated cost. If a borrower defaults, DOE is to pay off the loan and can either (1) take over the project for completion, operation, or disposition or (2) reach an agreement with the borrower to continue the project. To prevent default, DOE may make loan payments on behalf of the borrower, subject to appropriations and an agreement by the borrower for future reimbursement.

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[22] 71 *Federal Register* 46306, August 11, 2006.

[23] Ibid., p. 46329.

[24] Telephone conversation with Marvin Shaw, DOE Office of General Counsel, May 16, 2006.

Because it is generally believed that Wall Street continues to view new commercial reactors as financially risky, the availability of federal loan guarantees could be a key element in attracting funding for such projects and reducing financing costs. The federal government would bear most of the risk, facing potentially large losses if borrowers defaulted on reactor projects that could not be salvaged. Loan guarantees may be especially important for nuclear projects undertaken by deregulated generating companies as opposed to traditionally regulated utilities, which can recover their regulator-approved capital costs from ratepayers. Even for regulated utilities, "loan guarantees are critically important to new nuclear plant financing," the Nuclear Energy Institute contended in September 2006 testimony.[25]

DOE issued its initial solicitation for loan guarantees under EPACT on August 8, 2006.[26] The total amount of the loan guarantees in the initial solicitation is limited to $2 billion and does not include nuclear technology. Along with the initial solicitation, DOE issued guidelines for considering those initial proposals and said it was working on final regulations to govern future loan guarantee solicitations. The deadline for applications under the initial solicitation was originally November 6, 2006, but was subsequently delayed to December 31, 2006.

EPACT requires that before a loan guarantee is granted, the estimated subsidy cost (including estimated default losses) must be covered by a specific appropriation or by an up-front payment from the borrower. DOE's initial solicitation says that, because appropriations for the program are not anticipated, each borrower will have to pay the estimated subsidy cost. According to the solicitation, the subsidy cost will be calculated for each loan and must be approved by the Office of Management and Budget (OMB).[27] OMB will undoubtedly want to ensure that the payments are high enough to cover all the anticipated default and other subsidy costs incurred by the DOE loan guarantee program. The size of the payments required by OMB could strongly affect the value of the loan guarantees to borrowers.

Also important to potential borrowers is the percentage of project costs that can be covered by the DOE loan guarantees. Although EPACT Section 1702(c) allows DOE to provide loan guarantees for up to 80% of a project's estimated cost, DOE's guidelines for the initial solicitation "expresses a preference" that the loan guarantees cover not more than 80% of a project's debt.[28] Therefore, if a project has significant non-debt financing, the loan guarantees could cover considerably less than 80% of

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[25] Testimony of Skip Bowman, President and Chief Executive Officer, Nuclear Energy Institute, to the Energy and Water Development Subcommittee of the House Appropriations Committee, September 13, 2006.

[26] U.S. Department of Energy, Loan Guarantee Program Office, *Federal Loan Guarantees for Projects that Employ Innovative Technologies in Support of the Advanced Energy Initiative*, Solicitation Number DE-PS01-06LG00001, August 8, 2006.

[27] EPACT refers to the cost definition in the Federal Credit Reform Act of 1990, which defines the subsidy cost as "the estimated long-term cost to the government of a direct loan or a loan guarantee, calculated on net present value basis, excluding administrative costs."

[28] U.S. Department of Energy, *Loan Guarantees for Projects that Employ Innovative Technologies; Guidelines for Proposals Submitted in Response to the First Solicitation*, effective August 8, 2006.

the total cost. The Nuclear Energy Institute contended that "the procedures outlined in the guidelines are so restrictive and so conditional that they would not support financing of a nuclear power plant."[29]

Analysis of New Nuclear Power Plant Construction

Base Case Assumptions

To examine the potential competitive position of new nuclear plants, the future market price for electricity must be estimated. In the long run, the marginal cost of bringing on new electric generating capacity will tend to be set by the cost of the least expensive newly constructed generating plant. To evaluate the potential competitive position of nuclear power, CRS constructed an illustrative example involving four hypothetical powerplants: a conventional pulverized coal-fired facility, an advanced coal-fired facility based on integrated gasification combined-cycle (IGCC) technology, an advanced natural gas-fired combined-cycle facility, and an advanced nuclear power facility. The illustrative examples permit a consistent set of assumptions to use for the analysis.

Assessing the competitiveness of future nuclear power plants requires numerous assumptions about future economic, financial, and policy conditions. Based on 2015 as the benchmark year for constructing a new power plant, the major assumptions of the analysis are identified in **Table 2**. Most of the assumptions are from the Energy Information Administration (EIA) and reflect costs and technical performance anticipated by EIA for projects initiated in 2015.[30] The real capital charge rate is from the Environmental Protection Agency's Integrated Planning Model (IPM).[31] Calculations were done by CRS and are in constant 2004 dollars.

For nuclear fuel and coal costs, the assumptions reflect the price trends projected by EIA during the construction period. For coal, EIA projects stable prices in real terms from 2015 through 2023. For uranium, EIA projects stable prices in real terms between 2015 and 2030. Because natural gas prices have historically been more volatile than coal prices, CRS has performed a sensitivity analysis on natural-gas generating costs using a range of potential future natural gas prices. This sensitivity analysis, along with a general discussion of natural gas and coal prices, is presented after the base case results, which assume stable (in real terms) projected 2015 prices.

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[29] Testimony of Skip Bowman, *op. cit.*

[30] Energy Information Administration, *Assumptions to the Annual Energy Outlook — 2006 (With Projections to 2030)*, March 2006, pp. 71-87, at [http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf]. The term "initiated" is not defined.

[31] The real capital charge rate is calculated based on a 6.74% discount rate. For a full discussion, see Environmental Protection Agency, *Standalone Documentation for EPA Base Case 2004 (V.2.1.9) Using the Integrated Planning Model* (September 2005), chapter 7, at [http://www.epa.gov/airmarkets/epa-ipm/bc7financial.pdf].

Table 2. Projected 2015 Costs and Assumptions
(2004$)

Assumption	Coal Plant	Advanced Coal Plant	Advanced Natural Gas GCC	Advanced Nuclear Power Plant
Capital costs	$1,217/kw	$1,386/kw	$555/kw	$1,913/kw
Construction schedule	4 years	4 years	3 years	6 years
Fixed O&M costs	$25.07/kw-year	$35.21/kw-year	$10.65/kw-year	$61.82/kw-year
Variable O&M costs	0.418 cents/kwh	0.265 cents/kwh	0.182 cents/kwh	0.045 cents/kwh
Fuel costs	$1.40/million Btu	$1.40/million Btu	$5.08/million Btu	$0.66/million Btu
Heat rate	8,661 Btu/kwh	7,477 Btu/kwh	6,403 Btu/kwh	10,400 Btu/kwh
Capacity factor	90%	90%	90%	90%
Real capital charge rate	13.4%	13.4%	13.4%	13.4%
Date project initiated	2015	2015	2015	2015

Sources: DOE/EIA, *Assumptions to the Annual Energy Outlook 2006* (March 2006); EPA, *Standalone Documentation for EPA Base Case 2004* (September 2005).

Base Case Results

Assuming that by 2015 the subsidies contained in the 2005 Energy Policy Act are no longer available for new nuclear power construction, **Table 3** indicates that under EIA's assumed 2015 natural gas price scenario, conventional coal-fired and advanced combined-cycle natural gas-fired facilities would be in a virtual dead-heat as the choice for new construction. CRS estimates the annual costs on a levelized basis for new coal-fired or natural gas-fired facilities to be within one mill per kilowatt-hour (kwh) under EIA's estimated 2015 natural gas prices. Advanced coal-fired technology is projected to be competitive with both pulverized coal combustion and natural gas combined-cycle technology by 2015.

Without the production tax credit contained in the 2005 Energy Policy Act, a nuclear facility is not competitive with either coal-fired or natural gas-fired facilities under base case assumptions. Based on the assumptions above, CRS estimates that the break-even point for nuclear power capital costs versus coal-fired facilities initiated in 2015 is about $1,370 per kilowatt (kw) of capacity. This is substantially below the EIA projected cost of $1,913 per kw and is even below the vendors' estimate of $1,528 per kw (2004).[32] Under base case conditions, it seems unlikely that a new nuclear power plant would be constructed in the United States, barring a sustained, long-term increase in natural gas prices and the creation of a substantial, mandatory greenhouse gas reduction program that would increase coal-fired and natural gas-fired generating costs.

Table 3. Projected 2015 Annualized Costs
(2004$)

	Pulverized Coal Plant	Advanced Coal Plant	Advanced Natural Gas GCC	Advanced Nuclear Power Plant
Cents per kwh	4.5	4.6	4.6	5.6

Source: CRS calculations based on **Table 2** assumptions.

Impact of 2005 Energy Policy Act

However, if one assumes that the production tax credit contained in the 2005 Energy Policy Act is available to facilities that begin construction in 2015 (the base year in the analysis), the story is different. As indicated in **Table 4**, the production tax credit contained in EPACT is sufficient to make nuclear power competitive with either natural gas-fired or coal-fired facilities.

Table 4. Projected 2015 Annualized Costs, Including Subsidized Nuclear Power
(2004$)

	Pulverized Coal Plant	Advanced Coal Plant	Advanced Natural Gas GCC	Advanced Nuclear Power Plant	Advanced Nuclear Power Plant with Production Credit
Cents per kwh	4.5	4.6	4.6	5.6	4.2-4.7[a]

Source: CRS calculations based on **Table 2** assumptions.

a. Range reflects uncertainty with future inflation and construction times and dates, which affect the real value of the production credit.

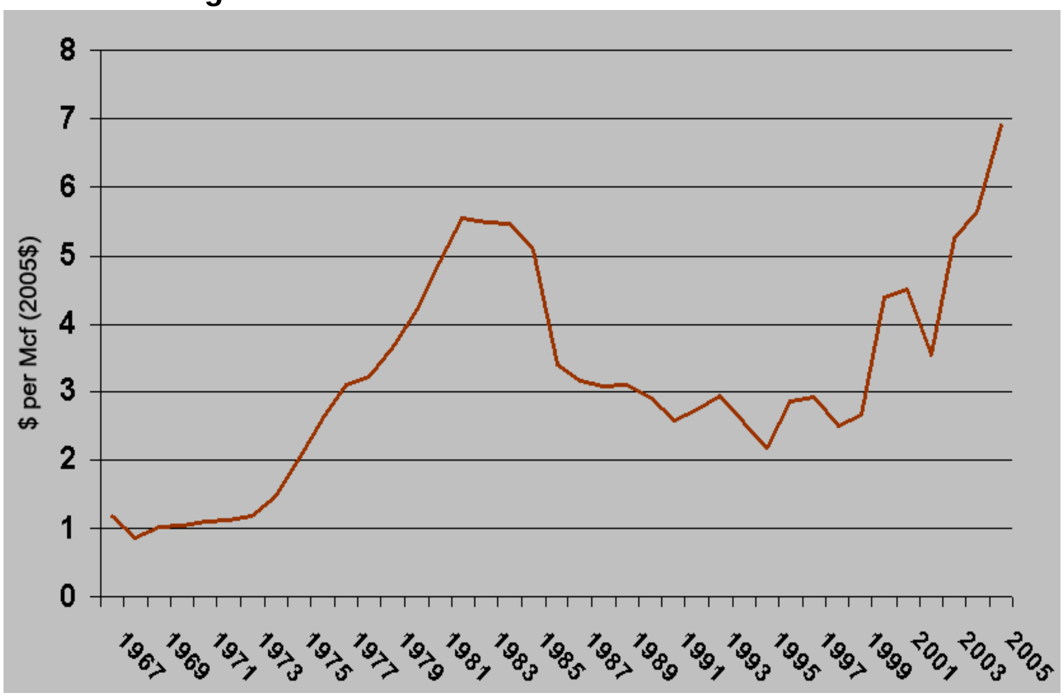
[32] Energy Information Administration, *Assumptions to the Annual Energy Outlook — 2006 (With Projections to 2030)*, (March 2006) p. 86, at [http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf].

The advantage provided to nuclear power by the production tax credit is not definitive; however, it appears sufficient to allow a decision on constructing a nuclear power station to move beyond initial economic considerations to examining other relevant factors, such as fossil fuel prices and the regulatory environment for both nuclear power and future fossil fuel-fired generation.

Sensitivity Analysis

Volatile Natural Gas Prices. Relatively high natural gas prices and the country's two-decade reliance on natural gas for new electric generating capacity have raised concern that the country is becoming too dependent on natural gas for electricity. Currently, about 22% of the country's electric generating capacity is natural gas-fired, compared with about 7% two decades ago. This situation raises at least two questions: (1) whether the recent rise in natural gas prices is a harbinger of future prices or just another peak in the historic boom-bust cycle of U.S. natural gas prices, and (2) whether nuclear power is an alternative generating option that the federal government should subsidize to help address question number one.

Figure 3. Natural Gas Prices Delivered to Electric Utilities



Source: Energy Information Administration, data available at [http://www.eia.doe.gov/emeu/aer/txt/stb0608.xls].

The potential for increased natural gas prices has been illustrated by recent events. However, power plants are long-lived facilities with lifetimes estimated at around 65 years, and current maintenance practices can extend that life almost indefinitely. In the emerging competitive environment for new power plant construction, the financial investment lifetime may be on the order of 20 years. This shorter time frame to recover a power plant investment reflects the uncertainty existing in the electricity market.[33]

Twenty years is a long time in the natural gas and coal markets. **Figure 3** charts natural gas prices to electric utilities during the 38 years from 1967 to 2005. Converted to real 2000 dollars using the Implicit Price Deflator, the chart indicates that natural gas prices have generally stayed under $4.50 per thousand cubic feet (mcf) until 2003. It is uncertain how long the current relatively high prices may continue. As indicated in **Table 2**, EIA projects 2015 natural gas prices at $5.08 in 2004 dollars — above the levels of the 1990s, but below the prices of the last two years.

To illustrate the sensitivity of natural gas-fired electric generation to natural gas prices, **Table 5** provides estimates of generation costs for a range of natural gas prices. Based on these calculations, the breakeven point for unsubsidized nuclear power versus natural gas-fired facilities would be $6.65/mcf or million Btu (MMBtu) in 2004$. Thus, if the current level of natural gas prices continues in the long-term, nuclear power may not need any subsidies by the year 2015 to compete with natural gas-fired facilities.

Table 5. Effect of Natural Gas Prices on Production Costs
(2004$)

Natural Gas Price (delivered, $/MMBtu)	Production Costs (cents/kwh)
3.08	3.3
4.08	4.0
5.08	4.6
6.08	5.2
7.08	5.9

Source: CRS calculations based on **Table 2** assumptions.

As noted above, the economic question raised by this analysis is whether the current upturn in natural gas prices is a relatively short-term phenomenon, or does it reflect a new long-term premium for natural gas, based on its environmental and technological advantages and future availability? If the former, then building new nuclear power plants would be a questionable venture economically, unless their capital costs could be reduced substantially. If the latter, nuclear power construction could become attractive in the future if prices persist at above approximately $6.65 per MMBtu (2004$).

However, it should be noted that volatile natural gas prices do not have any direct effect on generating costs at coal-fired facilities. In contrast to natural gas

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[33] See Environmental Protection Agency, *Analyzing Electric Power Generation under the CAAA*, Office of Air and Radiation (March 1998), p. A2-12.

prices, coal prices generally have been on a slow, steady decline for 30 years. The increasing share of coal being supplied by large, low-cost surface mining operations in the West has contributed to a long-term downward trend in coal prices. Coal prices have risen in the past couple of years as demand has increased; however, with abundant reserves, a sustained increase would seem problematic.

Greenhouse Gas Control. Any substantial mandatory greenhouse gas control program would probably affect the cost of new coal-fired and natural gas-fired generation. In all current proposals before the Congress, nuclear power is assumed to have no greenhouse gas emissions. This "green" nuclear power argument has gotten some traction in think tanks and academia. As stated by MIT in its major study *The Future of Nuclear Power*: "Our position is that the prospect of global climate change from greenhouse gas emissions and the adverse consequences that flow from these emissions is the principal justification for government support of the nuclear energy option."[34] The industry also has been attempting to promote nuclear power as one solution to rising greenhouse gas emissions.[35] A few well-known environmentalists have expressed public support for nuclear power as part of the response to global climate change, although no major environmental group as yet has publically adopted that position.[36]

Despite strong Bush Administration opposition to mandatory greenhouse gas reduction programs, a number of congressional proposals to advance programs designed to reduce greenhouse gases were introduced in the 109th Congress,[37] and similar efforts have continued in the 110th Congress. None of these proposal have passed either house of Congress. The first effort to pass a mandatory greenhouse gas reduction program failed in 2003 on a 43-55 vote in the Senate. A similar effort was defeated in 2005 during the debate on the Energy Policy Act of 2005 on a 38-60 vote. This second, less favorable vote reflects the changed votes of four Senators who reportedly objected to the addition of nuclear power incentives to the 2005 version of the proposed legislation.[38] The proposals would have placed a cap on U.S. greenhouse gas emissions based on a 2001 baseline. The cap would have been implemented through a tradeable permit program to encourage efficient reductions.

However, concern that global climate change should be addressed by the Congress led 13 Senators to introduce S.Amdt. 866 — a Sense of the Senate resolution on climate change — during the debate on the Energy Policy Act of 2005.

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[34] Interdisciplinary MIT Study, *The Future of Nuclear Power*, Massachusetts Institute of Technology, 2003, p. 79.

[35] See the Nuclear Energy Institute (NEI) website at [http://www.nei.org/index.asp?catnum=1&catid=11].

[36] Patrick Moore, "Going Nuclear," *Washington Post*, April 16, 2006, p. B1.

[37] See CRS Report RS22076, *Climate Change: Summary and Analysis of the Climate Stewardship Act (S. 342, S. 1151, and H.R. 759)*, by Larry Parker and Brent Yacobucci, and CRS Report RL32755, *Air Quality: Multi-Pollutant Legislation in the 109th Congress*, by Larry Parker and John Blodgett.

[38] Ben Evans and Catherine Hunter, "Senate Rejects Global Warming Amendment," *CQ Today*, June 22, 2005.

The resolution finds that (1) greenhouse gases are accumulating in the atmosphere, increasing average temperatures; (2) there is a growing scientific consensus that human activity is a substantial cause of this accumulation; and (3) mandatory steps will be required to slow or stop the growth of greenhouse gas emissions. Based on these findings, the resolution states that it is the sense of the Senate that the Congress should enact a comprehensive and effective national program of mandatory, market-based limits and incentives on greenhouse gases that slow, stop, and reverse the growth of such emissions. This should be done in a manner that will not significantly harm the U.S. economy and will encourage comparable action by other countries that are the nation's major trading partners and contributors to global emissions. The resolution passed by voice vote after a motion to table it failed on a 43-54 vote.

Four proposals introduced in the 109th Congress had analyses conducted by EPA and others that estimated their costs. For the 110th Congress, five bills have been introduced, but none have accompanying cost analyses.[39] However, several of the bills analyzed during the 109th Congress have been reintroduced in the 110th Congress, although with some modifications. These include S. 317, which has the CO_2 control provisions of S. 2724 of the 109th Congress, S. 280 and H.R. 620, which are modified versions of S. 1151 of the 109th Congress, and continuing efforts to draft legislation based on recommendations by the National Commission on Energy Policy (NCEP). The bills of the 109th Congress included the following:

- S. 2724 (Senator Carper).[40] Would create a cap-and-trade permit program to reduce emissions of sulfur dioxide, nitrogen oxides, mercury, and carbon dioxide from electric generating facilities greater than 25 megawatts (mw). The CO_2 cap would be set in two phases, with affected facilities required to reduce emissions to 2006 levels by 2010, and then further reduce emissions to 2001 levels by 2015.

- NCEP Recommendation (draft legislation prepared by Senator Bingaman).[41] Would create an economy-wide tradeable permit program to begin limiting greenhouse gases. The proposal would mandate an accelerated reduction in the country's greenhouse gas intensity: Between 2010 and 2019, the proposal would require a 2.4% annual reduction in greenhouse gas emissions per dollar of projected gross domestic product (GDP). After 2019, this reduction would increase to 2.8% annually. The program would include a cost-limiting safety valve that allows covered entities to make a payment to DOE in lieu of reducing emissions. The initial price of

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[39] For a comparison of bills introduced in the 110th Congress, see CRS Report RL33846, *Climate Change: Greenhouse Gas Reduction Bills in the 110th Congress*, by Larry Parker.

[40] For more on S. 2724, see CRS Report RL32755, *Air Quality: Multi-Pollutant Legislation in the 109th Congress*, by Larry Parker and John Blodgett.

[41] For more on the proposal, see CRS Report RL32953, *Climate Change: Comparison and Analysis of S. 1151 and the Draft "Climate and Economy Insurance Act of 2005,"* by Brent Yacobucci and Larry Parker.

such payments would be $7 per ton in 2010, rising 5% annually thereafter.[42]

- S. 1151 (Senators McCain and Lieberman).[43] Would create an economy-wide cap-and-trade program to reduce emissions of six greenhouse gases to their 2000 levels by the year 2010. The flexible, market-based program would permit participation in pre-certified international trading systems and a carbon sequestration program to achieve part of the reduction requirement. The bill excludes residential and agricultural sources, along with entities that do not own a single facility that emits more than 10,000 metric tons of CO_2 equivalent annually.[44]

- S. 150 (Senator Jeffords).[45] Would create a cap-and-trade permit program to reduce emissions of sulfur dioxide, nitrogen oxides, and carbon dioxide, along with unit-by-unit controls on mercury emissions from electric generating facilities 15 mw or greater. The CO_2 cap would require affected entities to reduce their emissions to 1990 levels by 2010.

Table 6 indicates projected trade permit prices for the four proposals. As indicated, S. 2724 is estimated to have the lowest price, while S. 150 is projected to have the greatest. This differential reflects both the stringency of the various proposals and their scope (economy-wide versus electric generation only). The reader should note that the estimates come from a variety of sources, and significant uncertainty surrounds the actual cost of any greenhouse gas initiative (except for the NCEP proposal, which includes a safety valve that limits the upper price range on permits).

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[42] For a discussion of safety valves, see CRS Report RS21067, *Global Climate Change: Controlling CO_2 Emissions — Cost-Limiting Safety Valves,* by Larry Parker.

[43] A House version of the bill, H.R. 759, has been introduced by Representatives Gilchrest and Olver.

[44] For more on the bill, see CRS Report RS22076, *Climate Change: Summary and Analysis of the Climate Stewardship Act (S. 342, S. 1151, and H.R. 759),* by Larry Parker and Brent Yacobucci.

[45] For more on S. 150, see CRS Report RL32755, *Air Quality: Multi-Pollutant Legislation in the 109th Congress*, by Larry Parker and John Blodgett.

Table 6. Per-Ton CO_2 Permit Price Estimates for Greenhouse Gas Initiatives

(in 2004$/metric ton of CO_2)

Year	S. 2724[a]	NCEP Recommendations	S. 1151	S. 150
2015	$1.2	$5.9	$11.7	$25.8
2020	$2.5	$7.7	$14.9	$33.1

Sources: For S. 843 and S. 150: EPA, Office of Air And Radiation, *Multi-Pollutant Analysis: Comparison Briefing* (October 2005); for NCEP Recommendations: The National Commission on Energy Policy, *Ending the Energy Stalemate: A Bipartisan Strategy to Meet America's Energy Challenges* (December 2004); for S. 1151: Sergey Palsev, *et al*., *Emissions Trading to Reduce Greenhouse Gas Emissions in the United States: The McCain Lieberman Proposal* [S. 139], Report No. 97 (June 2003). Estimates converted into 2004$ using the GNP Implicit Price Deflator.

a. S. 2724 estimates based on analysis of S. 843 introduced in 108th Congress. The later deadlines in S. 2724 would probably result in slightly lower cost estimates than those presented here, all else being equal.

Table 7 indicates the effect that the four proposals would have on 2015 and 2020 generation costs by fuel source. As indicated, the first two proposals, S. 2724 and the draft proposal based on the NCEP recommendations, would have a minimal effect on fuel choice in 2015 and 2020, all else being equal. The third bill, S. 1151, would pull nuclear power about even with its coal-fired competition. The fourth, S. 150, would provide the greatest advantage to nuclear power. It is also the proposal that most resembles the requirements of the Kyoto Protocol (as least for electric generation).

Table 7. 2015 and 2020 Projected Annualized Costs with Increased Costs from Greenhouse Gas Legislation

(cents per kwh, 2004$)

	Pulverized Coal Plant		Advanced Coal Plant		Advanced Natural Gas GCC		Advanced Nuclear Power Plant
	2015	2020	2015	2020	2015	2020	
S. 2724[a]	4.6	4.7	4.7	4.8	4.6	4.7	5.6
NCEP Recommendations	4.9	5.1	5.0	5.1	4.8	4.9	5.6
S. 1151	5.4	5.7	5.4	5.6	5.0	5.1	5.6
S. 150	6.5	7.1	6.4	6.9	5.5	5.7	5.6

Source: CRS calculations based on **Table 6** estimates and **Table 2** assumptions.

a. S. 2724 estimates based on S. 843 introduced in 108th Congress. The later deadlines in S. 2724 would probably result in slightly lower cost estimates than those presented here, all else being equal.

To quantify the potential effect of permit prices (or an equivalent carbon tax) on fuel source for future electric generating capacity, **Table 8** provides the effects of a range of permit prices/carbon taxes on new electric generating cost under base case conditions. As indicated, the breakeven point for nuclear power versus natural gas-fired facilities is about $30 a metric ton (2004$); the breakeven point for nuclear power versus coal-fired facilities is about $15 a metric ton (2004$). Thus, over time, nuclear power could provide a form of safety valve for electric generation, if permit prices or a carbon tax became a permanent part of the electricity supply environment.

Table 8. Effect of Permit Prices/Carbon Tax on Electricity Production Costs

Permit Price or Carbon Tax (2004$/metric ton of CO_2)	Natural Gas (cents/kwh)	Conventional Coal (cents/kwh)	Advanced Coal (cents/kwh)
$5	4.8	4.9	5.0
$10	4.9	5.3	5.3
$15	5.1	5.7	5.7
$20	5.3	6.1	6.0
$25	5.4	6.5	6.4
$30	5.6	6.9	6.7
$35	5.8	7.3	7.0
$40	6.0	7.7	7.4

Source: CRS calculations based on **Table 2** assumptions.

Nuclear Waste. Highly radioactive spent fuel produced by nuclear reactors poses a disposal problem that could be a significant factor in the consideration of new nuclear plant construction. The Nuclear Waste Policy Act of 1982 (NWPA, P.L. 97-425) commits the federal government to providing for permanent disposal of spent fuel in return for a fee on nuclear power generation. However, the schedule for opening the planned national nuclear waste repository at Yucca Mountain, Nevada, has slipped far past NWPA's deadline of January 31, 1998. DOE currently hopes to begin receiving waste at Yucca Mountain by 2017.[46]

In the meantime, more than 50,000 metric tons of spent fuel is being stored in pools of water or shielded casks at nuclear facility sites.[47] NWPA limits the planned Yucca Mountain repository to the equivalent of 70,000 metric tons of spent fuel.

[46] U.S. Department of Energy, "DOE Announces Yucca Mountain License Application Schedule," news release, July 19, 2006.

[47] Data compiled by CRS. For table and details, see CRS Report RL32163, *Radioactive Waste Streams: An Overview of Waste Classification for Disposal*, byAnthony Andrews.

Because U.S. nuclear power plants discharge an average of 2,000 metric tons of spent fuel per year, the Yucca Mountain limit is likely to be reached before any new reactors begin coming on line.

Therefore, even if Yucca Mountain eventually begins operating as planned, it is unclear what ultimately would be done with spent fuel from new nuclear power plants under current law. In the near term, continued storage at reactor sites and interim storage at central locations would be the most likely possibilities. The primary long-term options include lifting the statutory cap on Yucca Mountain disposal, developing additional repositories, and reprocessing spent fuel for reuse of plutonium and uranium. The Bush Administration's Global Nuclear Energy Partnership proposal, unveiled in February 2006, envisions reprocessing as a way to reduce the amount of long-lived plutonium and highly radioactive cesium and strontium that would need to be placed in Yucca Mountain, thereby expanding its disposal capacity.[48]

The extent to which the nuclear waste issue could inhibit nuclear power expansion is difficult to assess. NRC has determined that onsite storage of spent fuel would be safe for at least 30 years after expiration of a reactor's operating license, which was estimated to be as long as 70 years. As a result, the Commission concluded that "adequate regulatory authority is available to require any measures necessary to assure safe storage of the spent fuel until a repository is available."[49] Therefore, NRC does not consider the lack of a permanent repository for spent fuel to be an obstacle to nuclear plant licensing. However, the Administration was concerned enough about repository delays to include a provision in its recent nuclear waste bill to require NRC, when considering nuclear power plant license applications, to assume that sufficient waste disposal capacity will be available in a timely manner.[50]

Six states — California, Connecticut, Kentucky, New Jersey, West Virginia, and Wisconsin — have specific laws that link approval for new nuclear power plants to adequate waste disposal capacity. Kansas forbids cost recovery for "excess" nuclear power capacity if no "technology or means for disposal of high-level nuclear waste" is available.[51] The U.S. Supreme Court has held that state authority over nuclear power plant construction is limited to economic considerations rather than safety, which is solely under NRC jurisdiction.[52] No nuclear plants have been ordered since

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[48] See the Department of Energy website at [http://www.gnep.energy.gov].

[49] NRC, *Waste Confidence Decision Review*, 55 *Federal Register* 38472, Sept. 18, 1990. The 1990 decision was reaffirmed by NRC on November 30, 1999, and NRC denied a petition to amend the decision August 10, 2005.

[50] "Nuclear Fuel Management and Disposal Act," transmitted to House Speaker Nancy Pelosi and Vice President Richard Cheney March 6, 2007, by Energy Secretary Samuel Bodman.

[51] Lovell, David L., Wisconsin Legislative Council Staff, *State Statutes Limiting the Construction of Nuclear Power Plants*, October 5, 2006.

[52] Wiese, Steven M., *State Regulation of Nuclear Power*, CRS Report prepared for the (continued...)

the various state restrictions were enacted, so their ability to meet the Supreme Court's criteria has yet to be tested.

The nuclear waste issue has also historically been a focal point for public opposition to nuclear power. Proposed new reactors that have no clear path for removing waste from their sites could face intensified public scrutiny, particularly at proposed sites that do not already have operating reactors.

[52] (...continued)
House Committee on Interior and Insular Affairs, Dec. 14, 1992, p. 18.