STATE OF VERMONT
PUBLIC SERVICE BOARD

Docket No. 7440

Petition of Entergy Nuclear Vermont Yankee, LLC,
And Entergy Nuclear Operation, Inc., for
Amendment of their Certificates of Public Good
And other approvals required under 10 V.S.A. §§
6501-6504 and 30 V.S.A. §§ 231(a), 248 & 254,
For authority to continue after March 21, 2012,
Operation of the Vermont Yankee Nuclear Power
Station, including the storage of spent-nuclear fuel

PREFILED TESTIMONY OF

WILLIAM R. JACOBS, JR., Ph.D.

ON BEHALF OF THE
VERMONT DEPARTMENT OF PUBLIC SERVICE

November 14, 2008

Summary: Dr. Jacobs describes the decommissioning requirements for Vermont Yankee and provides an analysis of the adequacy of the decommissioning fund given reasonable assumptions for the escalation of decommissioning costs and earning rates of the decommissioning fund.

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EXHIBITS:

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is William R. Jacobs, Jr., Ph.D. I am a Vice President of GDS Associates, Inc. My business address is 1850 Parkway Place, Suite 800, Marietta, Georgia, 30067.

Q. DR. JACOBS, PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I received a Bachelor of Mechanical Engineering in 1968, a Master of Science in Nuclear Engineering in 1969 and a Ph.D. in Nuclear Engineering in 1971, all from the Georgia Institute of Technology. I am a registered professional engineer and a member of the American Nuclear Society. I have more than thirty years of experience in the electric power industry including more than twelve years of power plant construction and start-up experience. I have participated in the construction and start-up of seven power plants in this country and overseas in management positions including start-up manager and site manager. As a loaned employee at the Institute of Nuclear Power Operations ("INPO"), I participated in the Construction Project Evaluation Program, performed operating plant evaluations and assisted in development of the Outage Management Evaluation Program. Since joining GDS Associates, Inc. in 1986, I have participated in rate case and litigation support activities related to power plant construction, operation and decommissioning. I have evaluated nuclear power plant outages at numerous

nuclear plants throughout the United States. I am currently on the management committee of Plum Point Unit 1, a 650 MWe coal fired power plant under construction near Osceola, Arkansas. As a member of the management committee, I assist in providing oversight of the EPC contractor for this project. My resume is included as Exhibit DPS-WRJ-1.

Q. WHAT IS THE NATURE OF YOUR BUSINESS?

A. GDS Associates, Inc. ("GDS") is an engineering and consulting firm with offices in Marietta, Georgia; Austin, Texas; Corpus Christi, Texas; Manchester, New Hampshire; Madison, Wisconsin; Manchester, Maine; Bellingham, Washington; and Auburn, Alabama. GDS provides a variety of services to the electric utility industry including power supply planning, generation support services, rates and regulatory consulting, financial analysis, load forecasting and statistical services. Generation support services provided by GDS include fossil and nuclear plant monitoring, plant ownership feasibility studies, plant management audits, production cost modeling and expert testimony on matters relating to plant management, construction, licensing and performance issues in technical litigation and regulatory proceedings.

II. ASSIGNMENT

Q. WHAT WAS YOUR ASSIGNMENT IN THIS PROCEEDING?

My firm, GDS Associates, Inc. was retained to assist the DPS in development of an analysis of many issues relating to the license renewal at Vermont Yankee. We refer to this as the Act 160 report. DPS also requested GDS personnel to

develop testimony to be filed in Docket 7440 based on the results presented in several of the Act 160 report chapters. I drafted the Act 160 report chapter on decommissioning. This testimony presents the results of my analysis of decommissioning of Vermont Yankee and includes the Act 160 report chapter on decommissioning as Exhibit DPS-WRJ-2.

III. CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING DECOMMISSIONING FUNDING FOR VERMONT YANKEE.

A. Based on my review and analysis of the decommissioning cost estimates for Vermont Yankee and the current funding in the Vermont Yankee decommissioning fund, I reached the following conclusions:

1. The Vermont Yankee decommissioning cost analysis uses state-of-the-art, site specific methodology for estimating decommissioning costs at Vermont Yankee. This methodology is the accepted method used by most nuclear plant owners and the study was conducted by the firm recognized as the most experienced in conducting decommissioning cost studies.[1] The estimated decommissioning costs for the eight scenarios analyzed are reasonable based on the current knowledge of decommissioning costs.
2. The Vermont Yankee decommissioning trust fund appears to be adequate to fund all decommissioning scenarios based upon a plant shutdown in 2032

[1] The Vermont Yankee Decommissioning Cost Analysis was conducted by TLG Services, Inc., an Entergy subsidiary. TLG Services is the industry leader in decommissioning cost analysis and has performed decommissioning cost analyses for a majority of the U.S. nuclear power plants.

given reasonable assumptions for fund earnings and decommissioning cost escalation rates of 3% and 4%. However, recent experience with the decrease in value of the decommissioning trust fund and current performance of the equities markets demonstrates the need for continuous monitoring of fund earnings and the potential for additional contributions to the fund if conditions warrant. With a plant shutdown in 2012 the Vermont Yankee decommissioning trust fund is adequate to fund all decommissioning scenarios except for Scenarios 1 and 3 given reasonable assumptions for fund earnings and decommissioning cost escalation of 3%. With a decommissioning cost escalation rate of 4%, scenarios 5 and 7 are at the high end of the reasonable range.[2]

3. The primary cost driver between the decommissioning scenarios is the cost to store and maintain spent fuel. These costs are driven by the schedule for the DOE to begin and complete removal of spent fuel from the Vermont Yankee site.

4. Renewal of the Vermont Yankee operating license will have little impact on the cost to decommission the plant or on the amount of low level radioactive waste requiring disposal during decommissioning. The most significant

[2] On October 14, 2008, Entergy submitted a revised spent fuel management plan to the USNRC to demonstrate financial assurance of funding for spent fuel management. This plan extends the SAFSTOR period to 2072, assumes a 2% annual real rate of return on the decommissioning trust and requires a $60 million deposit by Entergy into the decommissioning trust in 2026. In the plan, Entergy states that it will request an exemption from NRC regulations to utilize decommissioning funds for spent fuel management. This plan is described in more detail in Exhibit DPS-WRJ-2.

impact of license renewal will be the amount of spent fuel generated and stored at the Vermont Yankee site until removal by the DOE.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING DECOMMISSIONING FOR CONSIDERATION BY THIS COMMISSION?

A. Yes I do. Decommissioning cost estimates and funding analyses are only as accurate as the underlying assumptions. To ensure that the decommissioning cost estimates and funding analyses are as accurate as possible, I have the following recommendations.

1. The owner of Vermont Yankee should conduct periodic reviews of the assumed decommissioning costs and fund earnings to ensure that the assumptions used in the cost and funding studies are accurate and reflect the most recent cost experience in actual plant decommissioning and the most recent fund earnings rates. These reviews should be conducted every three years or more frequently when significant changes to decommissioning costs or fund earnings are identified.
2. The owner of Vermont Yankee should submit to the Public Service Board and Department of Public Service the periodic analyses of the adequacy of decommissioning funding that demonstrate that the decommissioning fund is adequate to address likely decommissioning scenarios. These analyses should

provide the bases and support for the assumed decommissioning cost escalation and fund earnings.

3. If the periodic decommissioning funding report indicates that the existing decommissioning fund is not adequate to fund a reasonable decommissioning scenario, the owner of Vermont Yankee should provide a course of action to ensure the adequacy of the fund including periodic contributions to the fund to increase the fund balance to an amount adequate to fund a reasonable decommissioning scenario.
4. The owner of Vermont Yankee should provide annual reports on the status of available sites for disposal of low level radioactive waste including the Texas Compact and other low level waste repositories.
5. The owner of Vermont Yankee should take the necessary actions to ensure that access to a low level waste repository will be available at the time of decommissioning.
6. The owner of Vermont Yankee should survey the Vermont Yankee site to determine the amount of contaminated soil at the site. The costs of removal of contaminated soil should be included in future decommissioning cost estimates.

Q. HAVE YOU PROVIDED THE BASES FOR YOUR CONCLUSIONS AND RECOMMENDATIONS?

A. Yes, the bases for my recommendations and conclusions are provided in the Act 160 report chapter on decommissioning which is attached to this testimony as Exhibit DPS-WRJ-2.

Q. DOES THAT CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes it does.

Exhibit DPS-WRJ-1

Resume of William R. Jacobs, Jr.

EDUCATION: Ph.D., Nuclear Engineering, Georgia Tech 1971
MS, Nuclear Engineering, Georgia Tech 1969
BS, Mechanical Engineering, Georgia Tech 1968

ENGINEERING REGISTRATION: Registered Professional Engineer

PROFESSIONAL MEMBERSHIP: American Nuclear Society

EXPERIENCE:

Dr. Jacobs has over thirty-five years of experience in a wide range of activities in the electric power generation industry. He has extensive experience in the construction, startup and operation of nuclear power plants. While at the Institute of Nuclear Power Operation (INPO), Dr. Jacobs assisted in development of INPO's outage management evaluation group. He has provided expert testimony related to nuclear plant operation and outages in Texas, Louisiana, South Carolina, Florida, Wisconsin, Indiana, Georgia and Arizona. He currently provides nuclear plant operational monitoring services for GDS clients. He is assisting the Florida Office of Public Counsel in monitoring the development of four new nuclear units in the State of Florida. He will provide testimony concerning the prudence of expenditures for these nuclear units. He has assisted the Georgia Public Service Commission staff in development of energy policy issues related to supply-side resources and in evaluation of applications for certification of power generation projects and assists the staff in monitoring the construction of these projects. He has also assisted in providing regulatory oversight related to an electric utility's evaluation of responses to an RFP for a supply-side resource and subsequent negotiations with short-listed bidders. He has provided technical litigation support and expert testimony support in several complex law suits involving power generation facilities. He monitors power plant operations for GDS clients and has provided testimony on power plant operations and decommissioning in several jurisdictions. Dr. Jacobs represents a GDS client on the management committee of a large coal-fired power plant currently under construction. Dr. Jacobs has provided testimony before the Georgia Public Service Commission, the Public Utility Commission of Texas, the North Carolina Utilities Commission, the South Carolina Public Service Commission, the Iowa State Utilities Board, the Louisiana Public Service Commission, the Florida Public Service Commission, the Indiana Regulatory Commission, the Wisconsin Public Service Commission, the Arizona Corporation Commission and the FERC.

A list of Dr. Jacobs' testimony is available upon request.

1986-Present GDS Associates, Inc.

As Vice-President, Dr. Jacobs directs GDS' nuclear plant monitoring activities and has assisted clients in evaluation of management and

technical issues related to power plant construction, operation and design. He has evaluated and testified on combustion turbine projects in certification hearings and has assisted the Georgia PSC in monitoring the construction of the combustion turbine projects. Dr. Jacobs has evaluated nuclear plant operations and provided testimony in the areas of nuclear plant operation, construction prudence and decommissioning in nine states. He has provided litigation support in complex law suits concerning the construction of nuclear power facilities.

1985-1986 Institute of Nuclear Power Operations (INPO)

Dr. Jacobs performed evaluations of operating nuclear power plants and nuclear power plant construction projects. He developed INPO Performance Objectives and Criteria for the INPO Outage Management Department. Dr. Jacobs performed Outage Management Evaluations at the following nuclear power plants:

- Connecticut Yankee - Connecticut Yankee Atomic Power Co.
- Callaway Unit I - Union Electric Co.
- Surry Unit I - Virginia Power Co.
- Ft. Calhoun - Omaha Public Power District
- Beaver Valley Unit 1 - Duquesne Light Co.

During these outage evaluations, he provided recommendations to senior utility management on techniques to improve outage performance and outage management effectiveness.

1979-1985 Westinghouse Electric Corporation

As site manager at Philippine Nuclear Power Plant Unit No. 1, a 655 MWe PWR located in Bataan, Philippines, Dr. Jacobs was responsible for all site activities during completion phase of the project. He had overall management responsibility for startup, site engineering, and plant completion departments. He managed workforce of approximately 50 expatriates and 1700 subcontractor personnel. Dr. Jacobs provided day-to-day direction of all site activities to ensure establishment of correct work priorities, prompt resolution of technical problems and on schedule plant completion.

Prior to being site manager, Dr. Jacobs was startup manager responsible for all startup activities including test procedure preparation, test performance and review and acceptance of test results. He established the system turnover program, resulting in a timely turnover of systems for startup testing.

As startup manager at the KRSKO Nuclear Power Plant, a 632 MWE PWR near Krsko, Yugoslavia, Dr. Jacobs' duties included development and review of startup test procedures, planning and coordination of all startup test activities, evaluation of test results and customer assistance with regulatory questions. He had overall responsibility for all startup testing from Hot Functional Testing through full power operation.

1973 - 1979 NUS Corporation

As Startup and Operations and Maintenance Advisor to Korea Electric Company during startup and commercial operation of Ko-Ri Unit 1, a 595 MWE PWR near Pusan, South Korea, Dr. Jacobs advised KECO on all phases of startup testing and plant operations and maintenance through the first year of commercial operation. He assisted in establishment of administrative procedures for plant operation.

As Shift Test Director at Crystal River Unit 3, an 825 MWE PWR, Dr. Jacobs directed and performed many systems and integrated plant tests during startup of Crystal River Unit 3. He acted as data analysis engineer and shift test director during core loading, low power physics testing and power escalation program.

As Startup engineer at Kewaunee Nuclear Power Plant and Beaver Valley, Unit 1, Dr. Jacobs developed and performed preoperational tests and surveillance test procedures.

1971 - 1973 Southern Nuclear Engineering, Inc.

Dr. Jacobs performed engineering studies including analysis of the emergency core cooling system for an early PWR, analysis of pressure drop through a redesigned reactor core support structure and developed a computer model to determine tritium build up throughout the operating life of a large PWR.

SIGNIFICANT CONSULTING ASSIGNMENTS:

Florida Office of Public Counsel – Assists the Florida Office of Public Counsel in monitoring the development of four new nuclear power plants in Florida including providing testimony on the prudence of expenditures.

East Texas Electric Cooperative – Represents ETEC on the management committee of the Plum Point Unit 1 a 650 Mw coal-fired plant under construction in Osceola, Arkansas and represents ETEC on the management committee of the Harrison County Power Project, a 525 Mw combined cycle power plant located near Marshall, Texas.

Arizona Corporation Commission – Evaluated operation of the Palo Verde Nuclear Generating Station during the year 2005. Included evaluation of 11 outages and providing written and oral testimony before the Arizona Corporation Commission.

Citizens Utility Board of Wisconsin – Evaluated Spring 2005 outage at the Kewaunee Nuclear Power Plant and provided direct and surrebuttal testimony before the Wisconsin Public Service Commission.

Georgia Public Service Commission - Assisted the Georgia PSC staff in evaluation of Integrated Resource Plans presented by two investor owned utilities. Review included analysis of purchase power agreements, analysis of supply-side resource mix and review of a proposed green power program.

State of Hawaii, Department of Business, Economic Development and Tourism – Assisted the State of Hawaii in development and analysis of a Renewable Portfolio Standard to increase the amount of renewable energy resources developed to meet growing electricity demand. Presented the results of this work in testimony before the State of Hawaii, House of Representatives.

Georgia Public Service Commission - Assisted the Georgia PSC staff in providing oversight to the bid evaluation process concerning an electric utility's evaluation of responses to a Request for Proposals for supply-side resources. Projects evaluated include simple cycle combustion turbine projects, combined cycle combustion turbine projects and co-generation projects.

Millstone 3 Nuclear Plant Non-operating Owners – Evaluated the lengthy outage at Millstone 3 and provided analysis of outage schedule and cost on behalf of the non-operating owners of Millstone 3. Direct testimony provided an analysis of additional post-outage O&M costs that would result due to the outage. Rebuttal testimony dealt with analysis of the outage schedule.

H.C. Price Company – Evaluated project management of the Healy Clean Coal Project on behalf of the General Contractor, H.C. Price Company. The Healy Clean Coal Project is a 50 megawatt coal burning power plant funded in part by the DOE to demonstrate advanced clean coal technologies. This project involved analysis of the project schedule and evaluation of the impact of the owner's project management performance on costs incurred by our client.

Steel Dynamics, Inc. – Evaluated a lengthy outage at the D.C. Cook nuclear plant and presented testimony to the Indiana Utility Regulatory Commission in a fuel factor adjustment case Docket No. 38702-FAC40-S1.

Florida Office of Public Counsel - Evaluated lengthy outage at Crystal River Unit 3 Nuclear Plant. Submitted expert testimony to the Florida Public Service Commission in Docket No. 970261-EI.

United States Trade and Development Agency - Assisted the government of the Republic of Mauritius in development of a Request for Proposal for a 30 MW power plant to be built on a Build, Own, Operate (BOO) basis and assisted in evaluation of Bids.

Louisiana Public Service Commission Staff - Evaluated management and operation of the River Bend Nuclear Plant. Submitted expert testimony before the LPSC in Docket No. U-19904.

U.S. Department of Justice - Provided expert testimony concerning the in-service date of the Harris Nuclear Plant on behalf of the Department of Justice U.S. District Court.

City of Houston - Conducted evaluation of a lengthy NRC required shutdown of the South Texas Project Nuclear Generating Station.

Georgia Public Service Commission Staff - Evaluated and provided testimony on Georgia Power Company's application for certification of the Intercession City Combustion Turbine Project - Docket No. 4895-U.

Seminole Electric Cooperative, Inc. - Evaluated and provided testimony on nuclear decommissioning and fossil plant dismantlement costs - FERC Docket Nos. ER93-465-000, et al.

Georgia Public Service Commission Staff - Evaluated and prepared testimony on application for certification of the Robins Combustion Turbine Project by Georgia Power Company - Docket No. 4311-U.

North Carolina Electric Membership Corporation - Conducted a detailed evaluation of Duke Power Company's plans and cost estimate for replacement of the Catawba Unit 1 Steam Generators.

Georgia Public Service Commission Staff - Evaluated and prepared testimony on application for certification of the McIntosh Combustion Turbine Project by Georgia Power Company and Savannah Electric Power Company - Docket No. 4133-U and 4136-U.

New Jersey Rate Counsel - Review of Public Service Electric & Gas Company nuclear and fossil capital additions in PSE&G general rate case.

Corn Belt Electric Cooperative/Central Iowa Power Electric Cooperative - Directs an operational monitoring program of the Duane Arnold Energy Center (565 Mwe BWR) on behalf of the non-operating owners.

Cities of Calvert and Kosse - Evaluated and submitted testimony of outages of the River Bend Nuclear Station - PUCT Docket No. 10894.

Iowa Office of Consumer Advocate - Evaluated and submitted testimony on the estimated decommissioning costs for the Cooper Nuclear Station - IUB Docket No. RPU-92-2.

Georgia Public Service Commission/Hicks, Maloof & Campbell - Prepared testimony related to Vogtle and Hatch plant decommissioning costs in 1991 Georgia Power rate case - Docket No. 4007-U.

City of El Paso - Testified before the Public Utility Commission of Texas regarding Palo Verde Unit 3 construction prudence - Docket No. 9945.

City of Houston - Testified before Texas Public Utility Commission regarding South Texas Project nuclear plant outages - Docket No. 9850.

NUCOR Steel Company - Evaluated and submitted testimony on outages of Carolina Power and Light nuclear power facilities - SCPSC Docket No. 90-4-E.

Georgia Public Service Commission/Hicks, Maloof & Campbell - Assisted Georgia Public Service Commission staff and attorneys in many aspects of Georgia Power Company's 1989 rate case including nuclear operation and maintenance costs, nuclear performance incentive plan for Georgia and provided expert testimony on construction prudence of Vogtle Unit 2 and decommissioning costs of Vogtle and Hatch nuclear units - Docket No. 3840-U.

Swidler & Berlin/Niagara Mohawk - Provided technical litigation support to Swidler & Berlin in law suit concerning construction mismanagement of the Nine Mile 2 Nuclear Plant.

Long Island Lighting Company/Shea & Gould - Assisted in preparation of expert testimony on nuclear plant construction.

North Carolina Electric Membership Corporation - Prepared testimony concerning prudence of construction of Carolina Power & Light Company's Shearon Harris Station - NCUC Docket No. E-2, Sub537.

City of Austin, Texas - Prepared estimates of the final cost and schedule of the South Texas Project in support of litigation.

Tex-La Electric Cooperative/Brazos Electric Cooperative - Participated in performance of a construction and operational monitoring program for minority owners of Comanche Peak Nuclear Station.

Tex-La Electric Cooperative/Brazos Electric Cooperative/Texas Municipal Power Authority (Attorneys - Burchette & Associates, Spiegel & McDiarmid, and Fulbright & Jaworski) - Assisted GDS personnel as consulting experts and litigation managers in all aspects of the lawsuit brought by Texas Utilities against the minority owners of Comanche Peak Nuclear Station.

Exhibit DPS-WRJ-2

Act 160 Report Chapter on Nuclear Decommissioning

6.0 Nuclear Decommissioning

6.1 Description of Nuclear Decommissioning requirements

Nuclear Regulatory Commission regulations require that each operator of a nuclear power plant plan for the eventual decommissioning of the plant and ensure that adequate funding will be available to decommission the facility. Decommissioning as defined by the NRC means to remove nuclear facilities safely from service and to reduce residual radioactivity to a level that permits release of the property for unrestricted use and termination of the license. Decommissioning of nuclear facilities is necessary to protect the general public from the hazards presented by any radioactive materials that would remain at the facility at the end of its operating life. General guidance on decommissioning was provided by the NRC in its rule adopted on June 27, 1988.[1] This rule addressed planning needs, timing, funding methods and environmental review requirements. In 1996 the NRC published revisions to its general requirements for decommissioning.[2] The purpose of these revisions was to clarify ambiguities and to promote standardized procedures and terminology to improve efficiency and uniformity in decommissioning activities. In July 2000 the NRC issued Regulatory Guide 1.184 which further describes the methods and procedures that are acceptable to the NRC staff for implementing the requirements of the 1996 revised rule relating primarily to the initial activities and the major phases of decommissioning.

6.2 Types of Decommissioning

Three decommissioning alternatives acceptable to the NRC are defined as discussed below.

DECON: is defined as "the alternative in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed or decontaminated to a level that permits the property to be released for unrestricted use shortly after cessation of operations."

SAFSTOR: is defined as "the alternative in which the nuclear facility is placed and maintained in a condition that allows the nuclear facility to be safely stored and subsequently decontaminated (deferred decontamination) to levels that permit

[1] U.S. Code of Federal Regulations, Title 10, Parts 30, 40, 50, 51, 70 and 72 "General Requirements for Decommissioning Nuclear Facilities," Nuclear Regulatory Commission, Federal Register Volume 53, Number 123 (p 24018 et seq.), June 27, 1988

[2] U.S. Code of Federal Regulations, Title 10, Parts 2, 50, 51, "Decommissioning of Nuclear Power Reactors," Nuclear Regulatory Commission, Federal Register Volume 61, (p 39278 et seq.), July 29, 1996

release for unrestricted use." Areas of the plant are generally accessible to conduct maintenance as needed and monitor the condition of plant systems and structures. Decommissioning is generally required to be completed within 60 years.

ENTOMB: is defined as "the alternative in which radioactive contaminants are encased in a structurally long lived material such as concrete; the entombed structure is appropriately maintained and continued surveillance is carried out until the radioactive material decays to a level permitting unrestricted release of the property." Areas of the plant that have been entombed are not accessible to plant personnel. Decommissioning under this scenario must be completed within 60 years.

6.3 Decommissioning Funding Requirements

The NRC rule on decommissioning issued on June 27, 1988 defines decommissioning as described above and establishes technical requirements and a mechanism to ensure that sufficient financial assets will be available to cover the bulk of the activities necessary to decommission all nuclear power facilities. NRC Regulatory Guide 1.159 "Assuring the Availability of Funds for Decommissioning Nuclear Reactors" issued in August 1990 provides additional guidance to the operators of nuclear power plants and describes the financial methods acceptable to the NRC for providing the assurance required by the rule.

The rule required that each holder of an operating license submit a report to the NRC indicating how the licensee will provide reasonable assurance that funds will be available for decommissioning. The report was required to contain a cost estimate for the decommissioning and certification that one of three acceptable methods of providing financial assurance presented in the regulation would be utilized. The acceptable methods established by the rule are:

1. An external sinking fund that accumulates money for decommissioning gradually over the plant's operating life. Revenues earmarked for decommissioning are invested in a trust fund that is professionally managed.
2. A prepayment account into which the company makes deposits before the plant begins operation. The account may be a trust, escrow account, government fund, certificate of deposit or government

securities. It is kept separate from the company's other assets and is outside its control.

3. A surety bond, letter of credit or insurance, which guarantees that decommissioning costs will be paid if the company defaults on its obligation.

Nuclear plant operators have typically set up sinking funds to accumulate money to decommission nuclear power plants. It should be noted that the external sinking fund method of funding decommissioning anticipates that the decommissioning fund will be of adequate size to decommission that plant only at the end of the planned life of the facility and then only if the plant owner accurately forecasts the cost of decommissioning, the escalation of decommissioning costs and the fund earnings. Significant changes in any of these three factors can result in a fund shortfall at the end of the operating license. This can be seen as nuclear plant owners now have to plan for the construction of facilities for long-term on site storage of spent fuel and for the cost of operating these facilities for many years in the future. The SAFSTOR method of decommissioning allows for sufficient time for the decommissioning fund to grow to a level adequate for decommissioning the plant and for operation of spent fuel storage facilities until the DOE has removed fuel from the site.

6.4 Decommissioning Planning

Approximately five years before a nuclear plant operator plans to terminate plant operations, the operator must submit a preliminary decommissioning cost estimate to the NRC. This cost estimate is typically an update of biannual filings on estimated decommissioning costs and funding that each operator files with the NRC. Within two years of the shutdown, the operator must submit a post-shutdown decommissioning activities report to the NRC and affected states. This report must include a description of the planned decommissioning activities (DECON or SAFSTOR), a schedule for their completion, a discussion of how site-specific decommissioning activities will adhere to previously issued environmental impact statements and an estimate of expected costs. The plant operator is denied access to the full amount of decommissioning during operations until the site-specific cost estimate is submitted to the NRC.

The NRC will review the report and hold public meetings to discuss the operator's plans and the regulatory oversight process. If no objections are filed, the operator may

begin major decommissioning activities such as the permanent removal of major radioactive components at the end of 90 days.

6.5 Review of latest Vermont Yankee Decommissioning Study

The most recent study of Vermont Yankee decommissioning costs was conducted by TLG Services, Inc. (an Entergy subsidiary) and issued in January 2007. This study presents the results of a site-specific cost analysis based upon the design of Vermont Yankee, the quantities of various radioactive materials, estimated costs for disposal of low-level and high-level radioactive waste and site restoration to a greenfield condition as committed to by Entergy. The methodology employed in this study uses a unit cost factor approach and is based on identifying and estimating the decommissioning costs incurred in a wide variety of activities including:

- Decontamination Costs;
- Equipment Removal Costs;
- Packaging Costs;
- Transportation Costs;
- Off-site processing Costs;
- Low Level Radwaste Disposal Costs;
- Contingency;
- Spent Fuel Management Costs; and
- Site Restoration Costs.

This methodology is typical of site-specific decommissioning studies currently being performed and the TLG report generally follows the guidance presented in Regulatory Guide 1.159, Regulatory Guide 1.184 and other NRC requirements described above.

The volume of Class A, Class B, Class C and Greater than Class C radioactive wastes are estimated and used to estimate waste disposal costs. Craft man-hours and utility and contractor man-hours are estimated and priced. For each scenario analyzed, TLG provides:

- Total Cost to Decommission including contingency;
- Total NRC License Termination Cost;
- Spent Fuel Management Cost;
- Non-nuclear Demolition Cost;
- Low-Level Radioactive Waste Volume (Class A, B and C)

- Low Level Radioactive Waste Volume (Greater than Class C)
- Total Scrap metal removed; and
- Total Craft Labor Requirements.

A review of these data allows an understanding of the cost drivers for each scenario.

The TLG study evaluated eight scenarios based on a combination of shutdown dates (2012 or 2032), decommissioning alternative (DECON or SAFSTOR) and expectations of the dates that the Department of Energy (DOE) will begin and complete transfer of spent fuel to a federal repository. A summary description and the estimated cost for each decommissioning scenario are shown in Table 6.1below:

Table 6.1 Summary of Decommissioning Cost Analysis Scenarios

Scenario	Shutdown Date	Decom. Alternative	1st Spent Fuel Pickup	Last Spent Fuel Pickup	Cost (2006 $)
1	2012	DECON	2017	2042	728,146,000
2	2032	DECON	2017	2057	655,528,000
3	2012	DECON	2057	2082	893,379,000
4	2032	DECON	2042	2082	815,315,000
5	2012	SAFSTOR	2017	2042	803,732,000
6	2032	SAFSTOR	2017	2057	717,372,000
7	2012	SAFSTOR	2057	2082	991,115,000
8	2032	SAFSTOR	2042	2082	932,380,000

Variations in cost in these scenarios are primarily driven by the cost of spent fuel management. In the above scenarios license termination costs range from $450,128,000 in scenario 7 to $469,124,000 in scenario 8. The DECON scenarios (1 – 4) all had license termination costs of approximately $468,900,000. The site restoration costs for each scenario were also fairly consistent ranging from $40,053,000 in scenarios 1, 3 and 4 to $44,561,000 in scenario 2. By contrast, the spent fuel management costs showed significant variation ranging from $141,986,000 in scenario 2 (the least costly scenario) to $500,929,000 in scenario 7 (the most costly scenario.) Spent fuel management costs are driven by the requirement to construct an additional Independent Spent Fuel Storage Installation (ISFSI) in scenarios 1, 3,4,5,7 and 8 and the length of time that spent fuel remains on the Vermont Yankee site.

6.6 Adequacy of Vermont Yankee decommissioning funding

The adequacy of funding for decommissioning Vermont Yankee depends on six primary factors. These factors are:

- The balance in the decommissioning fund;
- The estimated cost of decommissioning;
- The earnings rate of the decommissioning fund;
- The rate of escalation of decommissioning costs;
- The period of time until decommissioning begins;
- The period of time until decommissioning is completed.

Several variables influence these primary factors including the escalation of labor rates for decommissioning workers, the escalation of radioactive waste disposal costs, the date on which the DOE will begin removing spent nuclear fuel from Vermont Yankee, the date on which the DOE will finish removing spent nuclear fuel from Vermont Yankee and whether or not the Vermont Yankee operating license is renewed to permit operation for an additional 20 years until 2032.

10 CFR 50.54(bb) requires that a nuclear plant operator file a report five years before expiration of the operating license that describes the program by which Vermont Yankee intends to manage and provide funding for the management of all irradiated fuel until title to the irradiated fuel is transferred to the Secretary of Energy. Entergy submitted the 10 CFR 50.54(bb) to the NRC on March 21, 2007. Entergy describes a scenario in which Vermont Yankee ceases operation in 2012, the DOE begins to accept spent fuel in 2017 and all spent fuel is removed from the site by 2042. This scenario is described as Scenario 5 in the decommissioning cost estimate. In this scenario, decommissioning of the plant begins in 2042 and is completed in 2050. Entergy discusses financial assurance on page 5 of the 50.54(bb) report stating:

> Assuming a 3% annual growth in the liability, an after-tax rate of return of 5.59% would be required to meet the distribution requirements identified in Table 3. At 4% annual rate of growth in the liability, the required rate of return increases to 6.62%.
>
> The decommissioning trust fund balance for Vermont Yankee was reported at $416.5 million as of December 31, 2006. Since Entergy VY acquired Vermont Yankee on July 31, 2002, on an after-tax basis, funds in the decommissioning have grown at an annual rate of 6.73%. At this rate, assuming liability growth at 4% or less, sufficient funds would be

> available to decommission Vermont Yankee (including caretaking of the spent fuel) under the scenario described.[3]
>
> The report further states:
>
> With the potential for an additional 20 years of fund growth[4], there is a corresponding and significant decrease in the earning requirements. For example, assuming the plant operates until 2032 and is then placed into SAFSTOR (Scenario 6 in the referenced analysis), the rate of return required is closer to 4%, assuming a 3% annual growth in the liability.[5]

Analysis of Decommissioning Funding

GDS has conducted an analysis of the Vermont Yankee decommissioning fund and forecast decommissioning costs to determine the required fund earning rate for the costs identified in the scenarios presented in the most recent decommissioning cost study by TLG.[6] The scenarios analyzed in the TLG study cover the range of reasonable decommissioning schedules from Scenario 1, prompt decommissioning (DECON) beginning in 2012 with spent fuel delivery to the DOE in 2017, to delayed decommissioning (SAFSTOR) beginning in 2032 with spent fuel delivery to the DOE beginning in 2057. GDS assumed an escalation rate of decommissioning costs of 3% and 4% and analyzed each scenario to determine if the scenario was viable; that is, could it be funded given the forecast costs and schedule, and if a scenario was determined to be viable, to determine the fund earnings rate that would be required to fund the annual expenditures identified in the TLG study.

The schedules of annual decommissioning expenditures (prepared by TLG Services, Inc. for Entergy) were entered into an Excel spreadsheet. The annual decommissioning expenditures for each year were escalated at rates of 3% and 4% to calculate the yearly expenditures in nominal dollars.

The analysis consisted of calculating the annual rate of return that the decommissioning fund would be required to earn in order for the fund balance as of September 30, 2008 ($397.0 million) plus fund earnings to support the decommissioning expenditures. Annual fund earnings were calculated by assuming that all expenditures would occur at mid-year, therefore annual earnings equal the average annual fund

[3] Vermont Yankee Nuclear Power Station License No. DPR-28 (Docket No. 50-271) Report pursuant to 10 CFR 50.54(bb) dated March 21, 2007, page 5 of 12.
[4] This scenario assumes that the Vermont Yankee license is renewed.
[5] Ibid.
[6] Vermont Yankee Nuclear Power Station Decommissioning Cost Analysis Document E11-1559-002, Rev. 0, Section 5, dated January 2007.

balance multiplied by the rate of return. The average annual fund balance is equal to the average of the beginning balance and the ending balance; the ending fund balance is equal to the beginning balance less annual expenditures.

The rate of return necessary for the fund to cover all expenditures was determined for each scenario by using the Excel 'Goal Seek' command. This command allows the determination of an input value that is necessary to achieve a desired result. For this analysis, the desired result is a decommissioning fund balance equal to zero at the end of the expenditure schedule. The 'Goal Seek' feature calculated the rate of return necessary to produce that zero balance.

The decommissioning fund earning rates required to provide the required funding for the decommissioning scenarios are shown in Table 6.2 below.[7] The detailed analyses including required annual expenditures and yearly decommissioning fund balances are provided in Attachment 6.1.

Table 6.2 Required Decommissioning Fund Earning Rate

Scenario	Shutdown Date	Decom. Alternative	1st Spent Fuel Pickup	Last Spent Fuel Pickup	Required Fund Earning Rate at 3% Escalation	Required Fund Earning Rate at 4% Escalation
1	2012	DECON	2017	2042	12.05%	13.50%
2	2032	DECON	2017	2057	5.07%	6.17%
3	2012	DECON	2057	2082	12.10%	13.53%
4	2032	DECON	2042	2082	5.61%	6.71%
5	2012	SAFSTOR	2017	2042	6.72%	7.89%
6	2032	SAFSTOR	2017	2057	4.60%	5.67%
7	2012	SAFSTOR	2057	2082	6.28%	7.42%
8	2032	SAFSTOR	2042	2082	4.82%	5.89%

As seen from these results, all scenarios except for Scenarios 1 and 3, the DECON scenarios beginning in 2012, can be funded with reasonably achievable fund earning rates, although scenarios 5 and 7 with a decommissioning cost escalation rate of 4% are at the high end of the range. Scenarios 1 and 3 require unreasonably high fund earning rates because of the early large expenditures required by the DECON

[7] The decommissioning fund earning rates shown in Table 6.2 are the rates required to generate sufficient earnings to fund the decommissioning and spent fuel management activities.

method before the decommissioning fund has the opportunity for significant growth. All of the SAFSTOR alternatives at a 3% cost escalation rate require reasonable decommissioning fund earning rates from 4.60% for Scenario 6 to 6.72% for Scenario 5. At a decommissioning cost escalation rate of 4%, SAFSTOR scenarios 6 and 8 require reasonable fund earning rates of 5.67% and 5.89% while scenarios 5 and 7 are at the high end of the range with required fund earnings of 7.89% and 7.42% respectively.

Note that the required fund earnings rates shown in Table 6.2 above were calculated based on the value of the decommissioning trust fund on September 30, 2008 of $397,035,937. The unprecedented market decline in October 2008 reduced the value of the decommissioning trust fund to $364,426,383. This decline in the value of the decommissioning trust fund would result in required fund earning rates somewhat higher than shown in Table 6.2. While this decline in the decommissioning trust fund is worrisome, it is reasonable to believe that over the 60 year life of the decommissioning fund, the earnings would approach historical rates.

NRC regulations require that unregulated utilities assume a fund earning rate of not more than 2% real rate of return. That is, the fund cannot be assumed to earn more than 2% above the assumed escalation rate of decommissioning costs. In table 6.2 above, the required real rate of return can be determined by subtracting the assumed escalation rate from the required rate of return shown in the table. For example, for scenario 6 in Table 6.2, the required real rate of return with an assumed cost escalation rate of 3% is 1.6%. This is calculated by subtracting the assumed cost escalation rate of 3% from the required rate of return of 4.6% to determine the required real rate of return of 1.6%.

Note that the calculations shown in Table 6.2 assume that decommissioning funds will be eligible for use to fund costs related to spent fuel management. On March 21, 2007 Entergy submitted its spent fuel management plan to the NRC[8] pursuant to the requirements of 10 CFR 50.54(bb), which requires that licensees of nuclear power plants that are within five years of the expiration of the reactor operating license submit written notification to the NRC for its preliminary review and approval of the licensee's program to manage and provide funding for management of all spent fuel at the reactor following permanent cessation of reactor operations. The NRC requested that Entergy submit a revised spent fuel management plan in part because the plan relied on withdrawals from

[8] Letter, Entergy to USNRC, Report Pursuant to 10CFR50.54(bb), BVY 07-007, dated March 21, 2007

the decommissioning trust for spent fuel management purposes, which is not permitted by regulations, and because Entergy assumed a rate of return on the decommissioning fund greater than the 2 % allowed by regulations for a nuclear plant not granted a higher rate of return by a regulating authority.[9] On October 14, 2008, Entergy submitted a revised spent fuel management plan to the NRC.[10] The revised plan is based on shutdown of Vermont Yankee in 2012 at the expiration of its current operating license. The plan extends the SAFSTOR period for 60 years such that decommissioning is completed in 2072. Adequate funding of decommissioning and spent fuel management is provided assuming a 2% annual real rate of return on the decommissioning fund and a deposit of $60 million into the decommissioning trust in the year 2026. Entergy further states that it will make appropriate submittals for an exemption in accordance with 10 CFR 50.12 from the requirements of 10 CFR 50.82(a)(8)(i)(A) in order to use the decommissioning trust funds for spent fuel management expenses. Entergy's revised spent fuel management plan is under review by the NRC.

6.7 Reasonableness of Assumed Fund Earning and Cost Escalation Rates

Assumed fund earning between 4.60% and 7.89% and a decommissioning cost escalation rate between 3% and 4% appear to be reasonable and consistent with the assumptions used at other nuclear power plants although, as mentioned above, the required fund earning rates for scenarios 5 and 7 at 4% cost escalation are at the high end of the range. A survey of 14 nuclear plants of similar vintage to Vermont Yankee revealed assumed fund earning rates from 3.0% to 7.49% and decommissioning cost escalation rates from 3.0% to 4.09%. The adequacy of decommissioning funds is driven in part by the difference between the fund earnings rate and the cost escalation rate. For the 14 nuclear plants described above this difference ranged from 1.79% to 3.4% with an average of 2.53%. As shown Attachment 6.1, a difference between fund earning and cost escalation between 1.67 % and 3.42% is sufficient to fund all but decommissioning scenarios 1, 3 and 5 with an assumed decommissioning cost escalation rate of 4%.

The Vermont Yankee Decommissioning Trust Fund Report dated September 30, 2007 provides the rates of return for the Vermont Yankee qualified and non-qualified

[9] Letter, USNRC to Entergy, Review of the Spent Fuel Management Plan, NVY 08-069, dated July 16, 2008
[10] Letter, Entergy to USNRC, Revised Spent Fuel Management Plan Pursuant to 10CFR50.54(bb), BVY 08-077, dated October 14, 2008

decommissioning funds. This report is provided as Attachment 6.2. Since the inception date of January 31, 2002, these funds have produced a weighted average after tax rate of return of 6.73%. This rate of return is sufficient to fund all but decommissioning scenarios 1 and 3 with a 3% cost escalation rate and all but scenarios 1, 3, 5 and 7 with a cost escalation rate of 4%. Note that scenarios 1, 3, 5 and 7 are the scenarios based on a 2012 shutdown. All scenarios based on a 2032 shutdown can be funded with reasonable fund earning rates.

When examining the escalation of estimated decommissioning costs for Vermont Yankee, one must take care that the comparison is an apples-to-apples comparison. Recent decommissioning cost estimates have included substantial sums for spent fuel management until the DOE removes all fuel from the site. These costs were not included in early decommissioning cost estimates. Looking at only costs for license termination and site restoration, the Vermont Yankee decommissioning cost estimate has increased from $312,736,000 for prompt decommissioning in 1994 to $508,897,000 for a similar scope of decommissioning activities in 2007. This cost increase represents a 3.82 % per year escalation rate, a rate that is consistent with the assumptions used in evaluating the adequacy of decommissioning funds.

6.8 Comparison of Vermont Yankee Decommissioning Fund to Other Nuclear Decommissioning Funds

The current level of funds in the Vermont Yankee decommissioning fund compares reasonably well with other nuclear power plants of similar vintage that have not yet renewed their operating license. The plant name, license expiration date and amount in their decommissioning fund as of December 31, 2006 or (December 2007 if available) is shown in the table below. While the decommissioning requirements for each plant are unique, the intent of these data is to show that the Vermont Yankee decommissioning fund is in the middle of a range of funds of similar plants.

Table 6.3. Comparison of Decommissioning Fund Levels[11]

Plant Name	Decommissioning Fund ($ millions)	License Expiration Date
Indian Point 1	254.2	
Crystal River 3	297.9	2016
Duane Arnold	264.2	2014
Indian Point 2	303.0	2014
Zion 1[12]	327.7	2013

[11] Funding levels from 10 CFR 50.75(f)(1) filings with the NRC

Zion 2	407.9	2014
Vermont Yankee	**427.4**	**2012**
Fitzpatrick	481.5	2014
Pilgrim	582.6	2012
Oyster Creek	650.8	2009

6.9 Impact of license renewal on decommissioning

The most significant impact of the proposed license renewal of Vermont Yankee on decommissioning of the plant is that more spent fuel will be generated that must be stored on site until it is transferred off site. The results of the most recent site-specific decommissioning cost estimate by TLG services Inc. show that there is little difference in the license termination costs[13] or the site restoration costs[14] if the site is shutdown in 2012 or continues operation to 2032. License Termination costs and Site Restoration costs for the eight decommissioning scenarios evaluated by TLG are shown in Table 6.4 below. The amount of low-level radioactive waste, Greater than Class C (GTCC) waste, Processed Waste and Scrap Metal for each shutdown scenario are also shown.

Table 6.4. Comparison of 2012 versus 2032 Shutdown[15]

Scenario	Shut-Down Date	License Termination Cost ($ million)	Site Restoration Cost ($ million)	Low-Level Waste Cu.Ft (1,000)	GTCC Waste Cu.Ft	Processed Waste Cu.Ft (1,000)	Scrap Meta (tons)l
1	2012	468.844	40.053	331.405	466	340.035	18,406
2	2032	468.981	44.465	330.212	466	340.035	18,406
3	2012	468.844	40.053	331.404	466	340.035	18,406
4	2032	468.981	40.053	333.062	466	340.035	18,406
5	2012	457.480	41.447	339.372	466	346.312	18,406
6	2032	455.368	41.446	336.113	466	346.312	18,406
7	2012	450.128	40.059	347.921	466	347.487	18,406
8	2032	469.124	43.266	348.220	466	347.487	18,406

These data demonstrate that there is very little difference in terms of cost or volume of radioactive waste for a shutdown in 2012 compared to a shutdown in 2032.[16]

[12] Decommissioning funds for Zion 1 and 2 are for radiological decommissioning only and are reported in beginning of year 2006 dollars

[13] License Termination costs are the costs associated with activities necessary to decommission the plant and allow the site to be released for public access.

[14] Site Restoration costs are costs associated with activities to return the site to the condition it was in prior to construction of the nuclear plant.

[15] Vermont Yankee Nuclear Power Station Decommissioning Cost Analysis Document E11-1559-002, Rev. 0, Section 5, dated January 2007.

One significant impact of license renewal on decommissioning is the additional time that the decommissioning fund has to grow before beginning decommissioning activities. As discussed above, the additional time prior to decommissioning afforded by license renewal significantly reduces the required earnings rate of the decommissioning fund to provide the needed funding.

6.10 Conclusions and Recommendations

Based on our review and analysis of the decommissioning cost estimates for Vermont Yankee and the current funding in the Vermont Yankee decommissioning fund, GDS has reached the following conclusions:

1. The Vermont Yankee decommissioning cost analysis uses state-of-the-art, site specific methodology for estimating decommissioning costs at Vermont Yankee. This methodology is the accepted method used by most nuclear plant owners and the study was conducted by the firm recognized as the most experienced in conducting decommissioning cost studies.
2. The estimated decommissioning costs for the eight scenarios analyzed are reasonable based on the current knowledge of decommissioning costs.
3. The Vermont Yankee decommissioning trust fund appears to be adequate to fund all decommissioning scenarios based upon a plant shutdown in 2032 given reasonable assumptions for fund earnings and decommissioning cost escalation rates of 3% and 4%. However, recent experience with the decrease in value of the decommissioning trust fund and current performance of the equities markets demonstrates the need for continuous monitoring of fund earnings and the potential for additional contributions to the fund if conditions warrant. With a plant shutdown in 2012 the Vermont Yankee decommissioning trust fund is adequate to fund all decommissioning scenarios except for Scenarios 1 and 3 given reasonable assumptions for fund earnings and decommissioning cost escalation of 3%. With a decommissioning cost escalation rate of 4%, scenarios 5 and 7 are at the high end of the reasonable range.

[16] This table provides the volumes of low level radioactive waste that would be generated during the decommissioning process. Additional high level radioactive waste (spent fuel) would be generated during an additional 20 years of plant operation.

4. A primary cost driver between the decommissioning scenarios is the cost to store and maintain spent fuel. These costs are driven by the schedule for the DOE to begin and complete removal of spent fuel from the Vermont Yankee site.
5. Renewal of the Vermont Yankee operating license will have little impact on the cost to decommission the plant or on the amount of low level radioactive waste requiring disposal during decommissioning. The most significant impact of license renewal will be the amount of spent fuel generated and stored at the Vermont Yankee site until removal by the DOE.

Decommissioning cost estimates and funding analyses are only as accurate as the underlying assumptions. To ensure that the decommissioning cost estimates and funding analyses are as accurate as possible, GDS provides the following recommendations.

1. The owner of Vermont Yankee should conduct periodic reviews of the assumed decommissioning costs and fund earnings to ensure that the assumptions used in the cost and funding studies are accurate and reflect the most recent cost experience in actual plant decommissioning and the most recent fund earnings rates. These reviews should be conducted every three years or more frequently when significant changes to decommissioning costs or fund earnings are identified.
2. The owner of Vermont Yankee should submit to the Public Service Board and Department of Public Service the periodic analyses of the adequacy of decommissioning funding that demonstrate that the decommissioning fund is adequate to address likely decommissioning scenarios. These analyses should provide the bases and support for the assumed decommissioning cost escalation and fund earnings.
3. If the periodic decommissioning funding report indicates that the existing decommissioning fund is not adequate to fund a reasonable decommissioning scenario, the owner of Vermont Yankee should provide a course of action to ensure the adequacy of the fund including periodic contributions to the fund to increase the fund balance to an amount adequate to fund a reasonable decommissioning scenario.
4. The owner of Vermont Yankee should provide annual reports on the status of available sites for disposal of low level radioactive waste including the Texas Compact and other low level waste repositories.

5. The owner of Vermont Yankee should take the necessary actions to ensure that access to a low level waste repository will be available at the time of decommissioning.
6. The owner of Vermont Yankee should survey the Vermont Yankee site to determine the amount of contaminated soil at the site. The costs of removal of contaminated soil should be included in future decommissioning cost estimates.