FILED
August 20, 2019
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANA MICHIGAN POWER COMPANY (I&M), AN INDIANA CORPORATION, FOR APPROVAL OF A CLEAN ENERGY PROJECT AND QUALIFIED POLLUTION CONTROL PROPERTY AND FOR ISSUANCE OF CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY FOR USE OF CLEAN COAL TECHNOLOGY AND COMPLIANCE WITH FEDERALLY MANDATED REQUIREMENT (PROJECT); FOR ONGOING REVIEW; FOR APPROVAL OF ACCOUNTING AND RATEMAKING, INCLUDING THE TIMELY RECOVERY OF COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF SUCH PROJECT THROUGH I&M'S CLEAN COAL TECHNOLOGY RIDER; FOR APPROVAL OF DEPRECIATION PROPOSAL FOR SUCH PROJECT; AND FOR AUTHORITY TO DEFER COSTS INCURRED DURING CONSTRUCTION AND OPERATION, INCLUDING CARRYING COSTS, DEPRECIATION, TAXES, OPERATION AND MAINTENANCE AND ALLOCATED COSTS, UNTIL SUCH COSTS ARE REFLECTED IN THE CLEAN COAL TECHNOLOGY RIDER OR OTHERWISE REFLECTED IN I&M'S BASIC RATES AND CHARGES.	))))))))))))))))	**CAUSE NO. 44523**

STIPULATION AND SETTLEMENT AGREEMENT

Indiana Michigan Power Company ("I&M" or "Company"), Intervenor Industrial Group ("Industrials"), and the Indiana Office of Utility Consumer Counselor ("OUCC"), (collectively the "Parties" or "Settling Parties" and individually "Party" or "Settling Party") solely for purposes of compromise and settlement and having been duly advised by their respective staff, experts and counsel, stipulate and agree that the terms and conditions set forth below represent a fair, just and reasonable resolution of all matters pending before the Commission in this Cause subject to their incorporation without modification or further condition that may be unacceptable to any Party into an order issued by the Indiana Utility Regulatory Commission ("Commission") as to which no person has filed a Notice of Appeal within a thirty day period after the date of the Commission order ("Final Order"):

A. TERMS AND CONDITIONS

The Settling Parties stipulate and agree that the terms of this Settlement Agreement are intended to address the issues indicated in the case caption. The full description of the request can be found in I&M's Application and supporting testimony. In short, the filing seeks approval to construct, install and operate Selective Catalytic Reduction (SCR) technology on I&M's Rockport Plant Unit 1 by December 31, 2017 ("Compliance Project"). I&M seeks to establish the cost recovery mechanisms and ongoing review to recover the costs related to the Compliance Project. I&M has a direct 50% ownership share in Rockport Unit 1 ("Ownership Share") and another 35% share of the costs under a FERC Unit Power Agreement ("Allocated Share"). As included in the I&M Application and supporting testimony, I&M requests timely recovery of the Ownership Share via a Clean Coal Technology Rider as a Clean Energy Project and Qualified Pollution Control Property pursuant to Indiana Code §§ 8-1-2-6.1, 8-1-2-6.7, 8-1-2-6.8, 8-1-8.7, 8-1-8.8-3, 8-1-8.8-11 and 170 Ind. Admin. Code 4-6-1 et seq. I&M also requests recovery of its Allocated Share of the Compliance Project under Indiana Code 8-1-8.4, commonly referred to as the Federal Mandate Statute.

1. For purposes of settlement, the Parties agree to Commission approval of I&M's request for a certificate of public convenience and necessity and associated ratemaking and accounting treatment as set forth in I&M's Application as supported by its case-in-chief and rebuttal testimony and as further modified by the enumerated terms included in this Settlement Agreement.

2. The Parties will not object to the reasonableness of the Rockport Unit 1 SCR Compliance Project in this proceeding or in future proceedings. This Settlement Agreement does not constitute a waiver of any right to challenge increases to cost estimates related to the Ownership Share under Indiana Code §8-1-8.7, and other statutes as may be applicable, in future proceedings.

3. The Parties agree that the Compliance Project associated with I&M's Ownership Share will be timely recovered under the traditional Clean Coal Technology method, as requested by I&M in its filings in this case. The Parties agree that I&M will withdraw, without prejudice, its request for recovery of the cost of the Compliance Project associated with I&M's Allocated Share from this case, as an agreed settlement term. The Parties further agree that I&M shall have the right to seek recovery of the Allocated Share of the Compliance Project according to the Federal Mandate statute any time on or after January 1, 2016. Such filing, on or after January 1, 2016, will not request the recovery of I&M's Allocated Share of the Compliance Project to begin until after the Project is in service and billed to I&M by AEG. The Parties also agree that this agreement to defer the request for authority to recover the I&M Allocated Share of the Compliance Project according to the Federal Mandate statute does not preclude I&M from seeking recovery of

any costs should a basic rate case be filed prior to that time. This Settlement Agreement does not constitute a waiver of any right a party may have to contest the cost recovery in any proceeding initiated by I&M to implement recovery of the Allocated Share of the Compliance Project

4. The Parties agree that I&M will not remove accumulated deferred income taxes (ADIT) from the weighted average cost of capital (WACC) and offset rate base as I&M had sought in its request.

5. The Parties agree that I&M will consider carbon pricing as part of its Integrated Resource Planning process and share its analysis with the stakeholders in that process.

B. PRESENTATION OF THE SETTLEMENT TO THE COMMISSION

1. The Settling Parties shall support this Settlement Agreement before the Commission and request that the Commission expeditiously accept and approve the Settlement Agreement. The concurrence of the Settling Parties with the terms of this Settlement Agreement is expressly predicated upon the Commission's approval of the Settlement Agreement in its entirety without any modification or any condition that may be unacceptable to any Settling Party.

2. The Settling Parties shall jointly move for leave to file this Settlement Agreement and supporting evidence, all of which will be offered into evidence without objection and the Settling Parties agree to waive cross-examination. The Settling Parties propose to submit this Settlement Agreement and evidence conditionally, and, if the Commission fails to approve this Settlement Agreement in its entirety without any change or with condition(s) unacceptable to any Settling Party, the

Settlement Agreement and all supporting evidence shall be deemed withdrawn and the Settling Parties agree that the proceeding will return to the same status as prior to the filing of the Settlement Agreement.

3. The Settling Parties shall jointly agree on the form, wording and timing of public/media announcement (if any) of this Settlement Agreement and the terms thereof.

C. EFFECT AND USE OF SETTLEMENT

1. It is understood that this Settlement Agreement is reflective of a negotiated settlement and neither the making of this Settlement Agreement nor any of its provisions shall constitute an admission by any Party to this Settlement Agreement in this or any other litigation or proceeding unless otherwise indicated. It is also understood that each and every term of this Settlement Agreement is in consideration and support of each and every other term.

2. This Settlement Agreement shall not constitute and shall not be used as precedent by any person in any other proceeding or for any other purpose, except to the extent necessary to implement or enforce the terms of this Settlement Agreement.

3. This Settlement Agreement is solely the result of compromise and except as provided herein, is without prejudice to and shall not constitute a waiver of any position that any of the Parties may take with respect to any or all of the items resolved here and in any future regulatory or other proceedings.

4. The Parties agree that the evidence of record and the additional evidence offered in support of this Settlement Agreement constitutes substantial evidence

sufficient to support this Settlement Agreement and provides an adequate evidentiary basis upon which the Commission can make any findings of fact and conclusions of law necessary for the approval of this Settlement Agreement, as filed. The Parties shall prepare and file an agreed proposed order with the Commission as soon as reasonably possible.

5. The communications and discussions during the negotiations and conferences and any materials produced and exchanged concerning this Settlement Agreement all relate to offers of settlement and shall be privileged and confidential, without prejudice to the position of any Party, and are not to be used in any manner in connection with any other proceeding or otherwise.

6. The undersigned Parties have represented and agreed that they are fully authorized to execute the Settlement Agreement on behalf of their designated clients, and their successors and assigns, who will be bound thereby.

7. The Parties shall not appeal or seek rehearing, reconsideration or a stay of the Final Order approving this Settlement Agreement in its entirety and without change or condition(s) unacceptable to any Party. The Parties shall support or not oppose this Settlement Agreement in the event of any appeal or a request for a stay by a person not a party to this Settlement Agreement or if this Settlement Agreement is the subject matter of any other state or federal proceeding. The provisions of this Settlement Agreement shall be enforceable by any Party before the Commission and thereafter in any state court of competent jurisdiction as necessary.

8. This Settlement Agreement may be executed in two (2) or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

ACCEPTED and AGREED as of the 8th day of January, 2015

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Attorney for I&M Industrial Group

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ORIGINAL

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VERIFIED PETITION OF INDIANA MICHIGAN POWER COMPANY ("I&M"), AN INDIANA CORPORATION, FOR APPROVAL OF CLEAN COAL AND ENERGY PROJECTS AND QUALIFIED POLLUTION CONTROL PROPERTY AND FOR ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR USE OF CLEAN COAL TECHNOLOGY ("PROJECTS"); FOR ONGOING REVIEW; FOR APPROVAL OF THE TIMELY RECOVERY OF COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF SUCH PROJECTS THROUGH I&M'S CLEAN COAL TECHNOLOGY RIDER; FOR APPROVAL OF DEPRECIATION PROPOSAL FOR SUCH PROJECTS; FOR AUTHORITY TO DEFER COSTS INCURRED DURING CONSTRUCTION AND OPERATION, INCLUDING CARRYING COSTS, DEPRECIATION, AND OPERATION AND MAINTENANCE COSTS, UNTIL SUCH COSTS ARE REFLECTED IN THE CLEAN COAL TECHNOLOGY RIDER, FOR APPROVAL OF COST RECOVERY OF COSTS INCURRED FOR ROCKPORT ENVIRONMENTAL PROJECT, ALL PURSUANT TO IND. CODE §§ 8-1-2-6.1, 8-1-2-6.7, 8-1-2-6.8, 8-1-2-42(a), 8-1-8.4-6, 8-1-8.4-7, 8-1-8.7, 8-1-8.8, AND 170 IAC 4-6-1 ET SEQ.	CAUSE NO. 44331 APPROVED: NOV 13 2013

ORDER OF THE COMMISSION

Presiding Officers:
Kari A. E. Bennett, Commissioner
Jeffery A. Earl, Administrative Law Judge

On April 11, 2013, Indiana Michigan Power Company ("I&M") filed its Verified Petition in this Cause. On April 15, 2013, I&M filed the direct testimony, exhibits, and workpapers of the following in support of its Petition: Paul Chodak III, I&M's President and Chief Operating Officer; John C. Hendricks, Director – Air Quality Services within the Environmental Services Division of American Electric Power Service Corporation ("AEPSC"); Scott C. Weaver, Managing Director – Resource Planning and Operational Analysis for AEPSC; Robert L. Walton, Managing Director of Projects for AEPSC; and Scott M. Krawec, I&M's Director of Regulatory Services.

On July 2, 2013, the Indiana Office of Utility Consumer Counselor ("OUCC") prefiled the direct testimony and exhibits of the following: Cynthia M. Armstrong, Utility Analyst; Edward T. Rutter, Utility Analyst; Ray L. Snyder, Utility Analyst; and Wes R. Blakley, Senior Utility Analyst. That same day, the I&M Industrial Group filed the direct testimony and exhibits of Nicholas Phillips, Jr., Managing Principal of Brubaker & Associates, Inc. On July 11, 2013, the OUCC filed the corrected testimony of Mr. Rutter and Ms. Armstrong. On July 15, 2013, I&M filed the rebuttal testimony and exhibits of Renee Hawkins, Managing Director, Coporate Finance for AEPSC, Mr. Krawec, and Mr. Weaver.

On July 24, 2013, the parties notified the Commission that they had reached a settlement of the issues in this case. On July 31, 2013, I&M filed the Settlement Agreement, supported by the testimony and exhibits of Mr. Krawec and Marc E. Lewis, I&M's Vice President. That same day, the OUCC filed the testimony of Mr. Blakley in support of the Settlement Agreement.

Pursuant to notice given and published as required by law, the Commission held an evidentiary hearing in this Cause on July 25, at which time the hearing was continued to August 7, 2013. On August 7, 2013, the Commission held a settlement hearing. During the hearing, the Parties presented their respective evidence and offered witnesses for cross-examination. No members of the general public attended or sought to participate in the hearing.

Based upon the applicable law and the evidence presented the Commission finds:

1. **Notice and Jurisdiction.** Notice of the hearings in this Cause was given and published as required by law. I&M is a public utility as defined in Ind. Code § 8-1-2-1(a) and Ind. Code § 8-1-8.7-2 and an eligible business as defined in Ind. Code § 8-1-8.8-6 and an energy utility as defined in Ind. Code § 8-1-8.4-3. Under Ind. Code chs. 8-1-8.7 and 8-1-8.8, the Commission has authority to approve the construction of and cost recovery for clean coal technology ("CCT") projects. Under Ind. Code ch. 8-1-8.4, the Commission has jurisdiction over the issuance of a certificate of public convenience and necessity ("CPCN") and cost recovery for federally mandated requirements. Therefore, the Commission has jurisdiction over I&M and the subject matter of this proceeding.

2. **I&M's Characteristics.** I&M, a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"), is a corporation organized and existing under the laws of the State of Indiana, with its principal offices at One Summit Square, Fort Wayne, Indiana. I&M is a member of the East Zone of the AEP System, which is operated on an integrated basis pursuant to the AEP Interconnection Agreement, a Federal Energy Regulatory Commission ("FERC") approved agreement that defines the sharing of costs and benefits associated with certain AEP East Zone affiliates' respective generating plants. I&M renders electric service in the State of Indiana, and owns, operates, manages, and controls, among other properties, plant and equipment within the State of Indiana that are in service and used in the generation, transmission, delivery, and furnishing of electric service to the public. In Indiana, I&M provides retail electric service to approximately 458,000 customers in the following counties: Adams, Allen, Blackford, DeKalb, Delaware, Elkhart, Grant, Hamilton, Henry, Howard, Huntington, Jay, LaPorte, Madison, Marshall, Miami, Noble, Randolph, St. Joseph, Steuben, Tipton, Wabash, Wells, and Whitley. I&M's electric system is an integrated and interconnected entity that is operated within Indiana and Michigan as a single utility.

3. Relief Requested in I&M Petition. I&M requests approval of the Settlement Agreement entered into between I&M, the OUCC, and the Industrial Group. The Settlement Agreement proposes that I&M's Rockport CCT Project be approved and that I&M be issued a CPCN for the Rockport CCT Project. The Settlement Agreement also proposes that, under the terms of Ind. Code ch. 8-1-8.4, I&M be allowed to recover the 80% of the costs of the Rockport CCT Project, among other costs, through a federally mandated costs rider, and to defer recovery of the remaining 20% of costs until rates are established in I&M's next general rate case.

4. I&M's Direct Evidence.

A. Background and Overview of I&M Compliance Project. Mr. Chodak explained that the Rockport Plant consists of two nominally-rated 1,300 megawatt ("MW") coal-fired generating units and is a cornerstone of I&M's generation fleet. Unit 1 was placed in service in 1984 and Unit 2 in 1989. Mr. Chodak explained that the Rockport CCT Project will install a dry sorbent injection ("DSI") system on both units at the Rockport Plant and modify existing equipment as needed to operate in conjunction with the DSI System. He stated that the Rockport CCT Project will allow the Rockport Plant to comply with the U.S. Environmental Protection Agency's ("EPA") Mercury and Air Toxics Standards ("MATS") Rule by April 16, 2015. Mr. Chodak testified that the Rockport CCT Project will not include a change in the fuel source used at the Rockport Plant because the required emission reductions can only be obtained through the continued use of Powder River Basin ("PRB") coal.

Mr. Chodak discussed the federal Consent Decree that AEP entered into to resolve allegations against AEP and its affiliates (including I&M) related to the New Source Review ("NSR") provisions of the Clean Air Act ("CAA"). The Consent Decree took effect on December 10, 2007, and, in pertinent part, included an agreement to retrofit Selective Catalytic Reduction ("SCR") and Flue Gas Desulphurization ("FGD") on Rockport Unit 1 by no later than December 31, 2017, and retrofit SCR and FGD on Rockport Unit 2 by no later than December 31, 2019. Mr. Chodak explained that since entering into the Consent Decree, I&M has continued to evaluate the most cost-effective means to achieve compliance with the Consent Decree and other pending and anticipated environmental regulations. Mr. Chodak discussed I&M's petition in Cause No. 44033, which I&M subsequently withdrew. He noted that the estimated cost of the compliance plan presented in Cause No. 44033 was approximately $1.4 billion. He stated that I&M continued to investigate other means with the potential to cost-effectively achieve compliance with the environmental regulations and Consent Decree requirements. Mr. Chodak testified that I&M's investigation included the testing of DSI technology at one of the Rockport Units to determine if it would allow I&M to meet existing environmental obligations in a more cost-effective manner. He said I&M determined that reasonable emission reductions were technologically feasible with DSI and legally permissible under the applicable environmental regulations, including the Consent Decree. Consequently, AEP and I&M approached the parties to the Consent Decree to confidentially discuss this compliance alternative. Mr. Chodak stated that the parties engaged in negotiations and ultimately agreed on modifications to the Consent Decree to allow the use of DSI as an environmental compliance measure.

Mr. Chodak explained that the modifications to the Consent Decree permit I&M to satisfy its near-term emission reduction obligations by installing and operating DSI technology on both Rockport Units by April 16, 2015. He added that I&M will secure an additional 200

MWs of wind energy, provide additional mitigation funding, and create a fund to support other energy efficiency and small scale renewable projects. He stated I&M will also change the fuel at or retire Tanners Creek Unit 4 by June 1, 2015. Witness Chodak also explained that AEP has accepted more restrictive system-wide emission caps on the AEP units subject to the Consent Decree. He testified that further emission reductions will be required at Rockport with the installation of SCR control equipment by the end of 2017 on one unit and by the end of 2019 on the other.

Mr. Walton described the DSI technology and AEP's experience with DSI technology, provided an overview of the equipment that will be installed on each unit as part of the DSI System for the Rockport CCT Project, and discussed the additional equipment that will be installed on the units, including the following: improvements to the existing Activated Carbon Injection ("ACI") system, electrostatic precipitators ("ESPs"), and ash handing systems; and expansion of the Ovation distributed controls system ("DCS") network and the existing Type II landfill. Mr. Walton also summarized the results of the DSI testing at Rockport.

Mr. Walton explained that the components of the Rockport CCT Project will directly or indirectly reduce regulated air emissions and are necessary to comply with the mandates established by the MATS Rule. More specifically, the operation of a DSI system on Rockport Units 1 & 2 will directly reduce airborne emissions of several regulated air pollutants. He stated that the DSI System is necessary to reduce hydrogen chloride ("HCl") emissions from each Rockport Plant unit to meet the MATS Rule. He testified that DSI technology is a patented product that was not in general commercial use at the same or greater scale in new or existing facilities in the United States at the time of enactment of the CAA amendments of 1990. The existing ACI System will be enhanced and used to comply with the MATS mercury emission limit while the improved ESPs will be used to control particulate matter emissions to meet the corresponding MATS limit. Mr. Walton explained that the Rockport CCT Project will allow I&M to continue using the existing and enhanced ACI System and noted that there will be an incremental increase in the O&M costs associated with the consumable to be used with the ACI System. Witness Walton testified that the Rockport CCT Project will increase the efficiency of operations required to meet MATS Rule compliance and added that this work is necessary to comply with this Rule.

Mr. Walton presented an overview of the project execution process and described the activities that will occur within each phase of this process. Mr. Walton also discussed the major benefits derived from the phased approach to construction projects. Mr. Walton also explained the process used to select a construction contractor for the Project and the project cost and schedule management process and other steps AEP takes to ensure that Project costs are reasonable and necessary. Mr. Walton explained the procurement/contract management process and described AEP's project risk, safety, and quality management processes.

Mr. Walton added that the Phase I Feasibility Studies cover the entire scope of the Rockport CCT Project and testified that the Division of Work for the project clearly defines the responsibilities of the assigned parties. He stated that AEP design criteria have been clearly communicated to the architect/engineer and the original equipment manufacturers to ensure the benefits of AEP's knowledge and experience in owning, maintaining and operating similar systems is carried forward on the Rockport CCT Project. Mr. Walton presented project documentation defining in detail how the project will be planned, executed, monitored, controlled, and closed.

B. Federally Mandated Requirements Driving I&M's Compliance Project. Mr. Hendricks described the applicable environmental regulations and other requirements that result in the need for the Rockport CCT Project. Witness Hendricks explained that the MATS Rule creates additional federal environmental requirements that necessitate new environmental control retrofits at the Rockport Plant. Compliance is required within three years of the effective date (with the possibility of a one-year compliance extension in certain circumstances). Mr. Hendricks explained that this rule regulates emissions of hazardous air pollutants ("HAPs") from coal- and oil-fired electric generating units. He said HAPs regulated by this rule are: 1) mercury; 2) several non-mercury metals such as arsenic, lead, cadmium, and selenium; 3) various acid gases including HCl; and 4) many organic HAPs. He testified that the MATS Rule includes stringent emission rate limits for several individual HAPs, including mercury. In addition, this rule contains alternative stringent emission rate limits for surrogates representing two classes of HAPs, acid gases and non-mercury particulate metal HAPs. He stated that the surrogates for the non-mercury particulate metal and acid gas HAPs are filterable particulate matter ("PM") and HCl respectively. He said the rule regulates organic HAPs through work practice standards.

Witness Hendricks testified that the proposed Rockport CCT Project is necessary to reduce HCl emissions from each Rockport Plant unit to meet the MATS Rule. He said the existing ACI system will be modified to comply with the MATS Rule mercury emission limit while the existing ESPs will be upgraded to control filterable PM emissions to meet the corresponding MATS Rule limit. Mr. Hendricks testified that without the Rockport CCT Project, the Rockport plant would not be able to meet the MATS Rule emission limits for acid gases and, therefore, would not be able to operate past April 15, 2015.

Mr. Hendricks discussed the environmental permits related to the project and in particular explained that the Rockport Plant's existing Indiana Department of Environmental Management ("IDEM") operating permit regulating air emissions must be modified before construction activities can commence onsite and added that the final modification was expected to be obtained within six months of the application, which was submitted to IDEM on February 27, 2013. Witness Hendricks also discussed future environmental regulations that could result in additional cost and operational impacts to I&M's generating units, including national ambient air quality standards ("NAAQS"), section 316(b) of the Clean Water Act, steam electric effluent guidelines, the coal combustion residuals rule ("CCR"), and greenhouse gas new source performance standards ("NSPS").

C. Estimated Cost of the Rockport CCT Project. In their direct testimony Mr. Chodak, Mr. Walton, and Mr. Krawec presented the total estimated cost of the Rockport CCT Project. Mr. Chodak noted that this total includes a cost estimate of $240.71 million for the Rockport CCT Project and approximately $44 million incurred in pursuing the installation of a dry scrubber on one unit at the Rockport Plant under Cause No. 44033 ("Rockport Environmental Project" or "REP").

Mr. Walton presented the cost estimate details broken down across four major areas, plus project management, engineering, and construction oversight staffing costs, a risk allocation, an AEP over-head allocations cost estimate, and an estimate for the construction of the new landfill and haul road. He explained how the cost estimate was developed. He stated that because the current level of site-specific project definition is less than 15%, the cost estimate for the Rockport CCT Project would be categorized as a Class 4 cost estimate by the Association of Advancement of Cost Engineering ("AACE"). He said typical accuracy ranges for Class 4 estimates are –15% to –30% on the low side, and +20 to +50% on the high side. However, based upon AEP's experience in executing projects such as these and its utilization of actual cost data from the recent DSI projects, he believes the range of accuracy is set to favor more toward the –15% to +20% range. Mr. Walton stated that I&M would be naïve to presume that all site-specific anomalies have been both recognized and accounted for in the estimate methodology and thus I&M had chosen to apply approximately 20% risk allocation to the estimated cost of the DSI and associated projects, excluding AEP Overheads - Allocations costs. He presented a formal risk assessment in Exhibit RLW-4. Mr. Walton discussed the overhead allocations and explained how I&M has accounted for escalation of labor and materials in the cost estimate. Mr. Walton also discussed the methods I&M employs to mitigate the risk of cost escalations that may affect the construction of the Rockport CCT Project.

D. **<u>Preconstruction Costs.</u>** Mr. Chodak and Mr. Walton discussed I&M's request to recover the costs of the dry flue gas desulfurization ("DFGD") portion of the REP project presented in Cause No. 44033. Mr. Walton explained that the total project cost spent to date as of February 28, 2013 is $44 million. He said I&M's 50% or total company share of the cost of the DFGD portion of the REP total project cost is $22 million.

Mr. Chodak explained that it was reasonable for I&M to incur these costs to assure that it would be in position to timely comply with environmental regulations and maintain the availability of generation from the designated unit. He pointed out that while I&M diligently pursued the alternative compliance strategy of using a lower-cost DSI System instead of the dry scrubber proposed in Cause No. 44033, it was not certain that DSI would be found to be an acceptable compliance measure under the Consent Decree. He testified that it was critically important for I&M to continue to move forward with the REP so that the Rockport Plant would be available for its customers in the event that DSI was not a cost-effective, technologically feasible, or a legally allowed environmental compliance measure.

E. **<u>I&M's Compliance Planning Process and Consideration of Alternative Compliance Plans.</u>** Mr. Weaver described the available options to fulfill the requirements of the MATS Rule, including an evaluation of the cost and feasibility of an option to retrofit and the option to retire and replace the Rockport Units. He also described the modeling process undertaken to evaluate the resulting relative economics of the alternative Rockport Unit 1 and 2 disposition options, including a discussion around the major input parameters and key drivers; chief among them the anticipated long-term price of natural gas and energy as well as CO_2/carbon that could impact the Rockport generating unit's dispatch priority.

This included a detailed overview of the resource planning-related criteria considered in his analysis, presentation of the key long-term fundamental commodity pricing projections used in this analysis, and a summary of the Rockport Units 1 and 2 unit disposition alternative analyses. Finally, Mr. Weaver discussed the results of these economic modeling analyses and the determination that a decision in the near-term to retrofit both Rockport Units 1 and 2 by April 16, 2015, with DSI technology and associated equipment would initiate a course of action around those units that could ultimately save I&M and its customers in excess of $2 billion versus alternative (replacement) approaches.

Mr. Weaver explained that two alternative options – with one of those alternatives posing two sub-options – were modeled surrounding an I&M disposition decision associated with Rockport Units 1 and 2. Succinctly, Option 1 was:

> Retrofit both Rockport units with DSI technology and associated equipment (Rockport CCT Project) by April 16, 2015: Option 1 also included, solely for purposes of the long-term modeling, the retrofit of the Rockport units with SCR technology for NO_x, removal by December 31, 2017 (Unit 1), and December 31, 2019 (Unit 2); add ash pond, effluent guideline waste-water treatment, and clean water act related equipment and investments by approximately 2019; and retrofit the Rockport units with NID™ DFGD technology by December 31, 2025 (Unit 1), and December 31, 2028 (Unit 2).

Option 2A was:

> Shorter-Term PJM Purchases: Retire both Rockport units by April 16, 2015, and Replace each with similar-sized, new-build Natural Gas Combined Cycle ("CC") and/or Natural Gas Simple-Cycle Combustion Turbine ("CT") units by approximately January 1, 2018, relying upon capacity and energy purchases from the PJM market in the interim period.

Option 2B was:

> Longer-Term PJM Purchases: same as Option #2A, except assume replacement new-build CC and/or CT units by approximately January 1, 2026.

Mr. Weaver explained that the inclusion of future investments in Option 1 simply offers – for current modeling purposes only – a potential unit disposition line-of-sight. He stated that under no circumstances does this option constitute a formal plan or recommendation by I&M for either Rockport unit beyond the "nearer-term" Rockport CCT Project. He clarified that the analysis merely identifies the "down-stream" retrofit requirements/terms of the Modified Consent Decree as well as additional emerging EPA requirements such as the CCR rule and 316(b). He reiterated Mr. Chodak's testimony that it would be the intent of I&M to approach this Commission at such point prior to the construction of the next critical-path Rockport unit retrofit – the SCRs – with another formal CPCN filing.

Mr. Weaver explained why the "staged" Rockport Unit retrofit plan represents a reasonable approach even if it were determined later this decade that the installation of an SCR and subsequent DFGD do not represent an appropriate Rockport Unit disposition path. He explained that the modeled cost-recovery period for the relatively lower (versus the down-stream costs of the SCR and DFGD) capital cost Rockport CCT Project to be completed in April 2015, as proposed in this filing, was assumed to be 10 years. He stated that a sensitivity analysis was also performed that would effectively proxy the costs associated with full recovery of this initial (DSI-related) retrofit investment by the end-of-2017 for Unit 1 (approximately 3-year recovery) and end-of-2019 for Unit 2 (approximately 5-year recovery), so as to fully understand the implications of such future disposition options around potential coinciding SCR-related retrofit versus retire dates later this decade. He added, in short, on a cumulative present worth basis, there was only a minor difference in the life-cycle costs of the 2015 Rockport CCT Project if all such costs were recovered over these shorter periods (versus 10 years). Therefore, he concluded the impact of any such potential for accelerated DSI retrofit cost recovery recognition would not have any significant impact on the base modeled option results to be discussed.

Mr. Weaver clarified that the assumption in the modeling that Rockport Unit 1 would be the earlier of the Unit retrofits for DFGD in the next decade was merely a modeling assumption. He said the Modified Consent Decree simply identifies that one Rockport unit would retrofit, retire, re-power or refuel by December 31, 2025, and the other by December 31, 2028. It is not specific as to the ultimate unit order. He explained that other options, such as coal-to-gas refuel and CC repower options were not modeled as out-year alternatives because I&M believes at this point that the future retrofitting of the Rockport units with DFGD would be a more reasonable and viable option – based on currently available cost estimates as well as engineering and design factors – versus re-fueling either of the units to burn natural gas or repowering the units as natural gas CC facilities. He clarified that any formal assessment of Rockport disposition options to be performed in the future could more-fully examine those alternatives.

Mr. Weaver discussed the base assumptions used in the economic modeling, including an assumption that Tanners Creek Unit 4 was to be re-fueled and Tanners Creek Units 1-3 were retired by June 1, 2015, and the assumption that the operating lease shares of Rockport Unit 2 would continue beyond the current 2022 lease term date. He noted that as with the other assumptions, the future lease disposition of Rockport Unit 2 is one that is independent of the nearer-term decision regarding the installation of the Rockport CCT Project posed in this Cause.

Mr. Weaver discussed how the Strategist model was used to perform the unit disposition alternatives analysis and identified the primary model outputs and inputs. Mr. Weaver also discussed the additional cost and performance risk. Mr. Weaver also explained why natural gas pricing is one of the key drivers for this analytical process and discussed the forecasted fundamental commodity pricing, including natural gas, which were used in the analyses.

Mr. Weaver presented the results of the Rockport Unit Disposition Analyses and explained the modeling results represent relative cost analyses, meaning each are compared to one another in the determination of the least-cost alternative outcome. He explained that the modeling results indicate that Option 2A would be more costly than Option 1 by $2.202 billion over the study period. He explained that the sensitivity pricing scenarios showed that Option 2A is more costly by amounts ranging from $2.012 billion to $2.932 billion. He testified that analysis showed that Option 2B would be more costly than Option 1 by $2.069 billion under the base pricing scenario and by amounts ranging from $1.795 billion to $2.891 billion under the sensitivity scenarios. Mr. Weaver explained that economic modeling shows that the Rockport CCT Project is clearly economically-favored across the full range of long-term commodity pricing scenarios modeled. He added that this suggests that this Rockport CCT Project solution has effectively preserved an option for I&M and its customers to consider, in the future, additional possible retrofitting of both Rockport Units 1 and 2 with, first, SCRs and, subsequently, DFGD technology as set forth under the Modified Consent Decree.

Mr. Weaver further discussed the economic results for the two market-based options (Option 2A and 2B) and concluded that both of the market-replacement options remain significantly more costly than I&M's proposed solution and are subject to additional market pricing and performance risks.

Finally, Mr. Weaver explained how price risk around natural gas, construction costs, and performance risk was assessed in the economic modeling.

F. Accounting and Ratemaking and Rate Impacts. Mr. Krawec explained I&M's requested accounting and ratemaking treatment related to the Rockport CCT Project, including I&M's request to include its share of the Rockport CCT Project costs in the CCTR. Mr. Krawec explained that I&M's proposal will provide for the timely ratemaking recognition of all costs incurred in the construction and operation of the Rockport CCT Project, including the ability to add to the value of I&M's property eligible for a return, the value of I&M's share of the Rockport CCT Project under construction and in service until such time as the Commission determines the Rockport CCT Project is used and useful in a proceeding that establishes new basic rates and charges for I&M.

Mr. Krawec explained how costs of the project are tracked and recorded on I&M's books and discussed how I&M would record construction work in progress ("CWIP") rate treatment to the Rockport CCT Project costs. Mr. Krawec explained that allowance for funds used during construction ("AFUDC") will accrue until the Rockport CCT Project has been under construction for at least six months, in accordance with 170 IAC 4-6-13. Mr. Krawec explained that I&M proposes to include related incremental O&M costs, including the cost of consumables used, in its CCTR. He added that I&M requests the Commission authorize I&M to defer incremental O&M costs incurred during the operation of the Rockport CCT Project until such time as such costs are reflected in the CCTR.

Mr. Krawec explained that the depreciation period for each unit CCT Project will commence once the scope of work associated with the operation of that unit is placed in service. He said I&M requests that the Commission authorize I&M to defer any depreciation expense incurred during the operation of the Rockport CCT Project until such time as such costs are reflected in the CCTR or are otherwise reflected in base rates.

With regard to I&M's requested accounting and ratemaking treatment regarding the cost incurred for the REP presented in Cause No. 44033, Mr. Krawec explained that I&M proposes to capitalize these costs as part of the Rockport CCT Project and recover these via the CCTR over the same period (10 years) as the Rockport CCT Project. He clarified that the $44 million includes the $10 million of costs approved for recovery in Cause No. 44033.

Mr. Krawec explained that I&M will use the same methodology for calculation of I&M's weighted cost of capital that I&M currently uses in its CCTR filings, Cause Nos. 43636 ECR X. Mr. Krawec testified the request for authority to defer depreciation expense, carrying costs, and incremental O&M costs until such costs are reflected in the CCTR is reasonable and necessary to insure timely recovery of the Rockport CCT Project as allowed by statute. He added that it would be virtually impossible and inefficient for I&M to perfectly time rate cases with the in-service dates of the Rockport CCT Project.

G. **Alternative Request Pursuant to Ind. Code ch. 8-1-8.4.** Mr. Krawec explained that if the Commission does not approve the request under the CCTR, then I&M seeks to implement a periodic retail rate adjustment mechanism that allows for the timely recovery of part of the approved federally mandated costs and a deferral to recover the rest in the next basic rate case. He stated that the periodic charge would recover eighty percent (80%) of the costs. He testified that under Ind. Code ch. 8-1-8.4, I&M requests an adjustment by the Commission of I&M's authorized net operating income to reflect any approved earnings for purposes of Ind. Code § 8-1-2-42(d)(3). He said the other 20% of the approved costs, including depreciation, AFUDC, and post-in-service carrying costs, based on the overall cost of capital approved by the Commission in Cause 44075, will be deferred and recovered by I&M as part of the next general rate case filed with the Commission.

H. **Ongoing Review.** With regard to the request for ongoing review included in I&M's case-in-chief, Mr. Krawec proposed that an ongoing review process would be conducted as part of I&M's semiannual CCTR proceedings in Cause No. 43636 ECR X.

5. **OUCC's Direct Evidence.** Mr. Rutter concluded that the Rockport CCT Project is a reasonable balance of costs, risks, and policy based on a retrofit approach to meeting the requirements of the MATS Rule. He testified that while there may be significant future expenditures required, uncertainty around the extension of the lease for Unit 2, and evolving environmental rules and requirements associated with coal-fired generation, the OUCC recommends that the Commission approve the Rockport CCT Project. He added that the OUCC also recommends that I&M provide updated estimates through the ECR proceedings, including any additional costs to comply with the Consent Decree and any revised costs as a result of any change to environmental rules and regulations.

Ms. Armstrong discussed the Project in light of existing or expected environmental regulations and supported the OUCC's overall recommendation that the Rockport CCT Project is reasonable and should be approved by the Commission.

Mr. Snyder presented an analysis of the Rockport CCT Project, and confirmed I&M's choice of technology and cost estimates. Mr. Snyder testified that the OUCC agreed the ACI and ESP system modifications are necessary and I&M's proposals for upgrading the ESP and ACI Systems appear reasonable. He concluded that the Rockport Units currently have in place air pollution control devices ("APCD") that could reasonably be modified, along with the addition of DSI for acid emissions, in order to comply with the current MATS regulations. He added that the OUCC has reviewed I&M's documents and preliminary cost estimates for potential future APCD projects. He concluded that I&M's plans for the future addition of SCRs and DFGDs are technically appropriate for meeting the anticipated future regulations. He clarified that even though they provide a reasonable path forward, the details and economics of future projects are not included in this proceeding and therefore cannot be assessed. Echoing the other OUCC witnesses, Mr. Snyder stated the OUCC recommends the Commission approve the I&M CPCN for the Rockport CCT Project.

6. **Disputed Issues.**

A. **Pre-Construction Costs.** Mr. Blakley testified that the $44 million that I&M spent on Preconstruction Costs for the REP proposed in Cause No. 44033 appear to be reasonable. He stated however, the OUCC proposes an alternative ratemaking treatment for these costs and does not agree that I&M should earn a return on these costs because they are not "used and useful" rate base assets and not CWIP that is eligible for a return. He noted that the OUCC questions whether I&M can earn a return on these costs, because they relate to a project that was never approved by the Commission and did not receive a CPCN under Ind. Code ch. 8-1-8.7. He added that while the REP still might be constructed in the future, it is not at all certain if I&M will actually carry through with its request for these projects by 2025. He concluded therefore, that the OUCC recommends that the costs of the projects be recovered through amortization over the remaining expected useful life of the Rockport facility.

Mr. Krawec explained that the Preconstruction Costs were undertaken as part of I&M's obligation to assure reasonably adequate electric service and facilities to meet its customers' need for service. He explained that Mr. Blakley's contention conflicts with the Uniform System of Accounts ("USOA") and Generally Accepted Accounting Principles ("GAAP") and testified that under USOA and GAAP, the Preconstruction Costs are eligible for AFUDC until a cash return on CWIP is recovered. He testified that these costs are appropriately capitalized to the Rockport CCT Projects and included in Electric Plant in Service ("EPIS") and that EPIS is allowed to earn a return. Mr. Krawec also explained that the ratemaking for $10 million of these capital costs approved in Cause No. 44033 infers that the Preconstruction Costs would be treated as any other cost charged to EPIS, which would be allowed a recovery of depreciation and a return.

Mr. Krawec reconciled his analysis with Mr. Weaver's analysis. He explained that the direct testimony cited by Mr. Snyder focused on the portion of the Preconstruction Costs that will be recorded on I&M's books. He explained that there is no conflict. Mr. Weaver considered the 85% of the total plant costs in his economic analysis and Mr. Krawec included the 85% of the total plant costs in his rate impact analysis.

B. **Double Recovery.** Ms. Armstrong stated that the OUCC is concerned that there may be double recovery issues because components of the existing ACI System that are currently included in rate base may be retired and replaced as part of the Rockport CCT Project. She also noted that there is already a level of O&M associated with operating the Rockport ACI Systems embedded in I&M's rates.

Mr. Krawec disagreed with the suggestion that costs reflected in the revenue requirement used to establish I&M's basic rates for electric service should be tracked as Ms. Armstrong suggests. He commented that many costs have changed since the adjusted test period used to establish I&M's retail rates. He explained that the premise underlying Ms. Armstrong's concern is inaccurate because I&M does not expect any retirements associated with the ACI Systems. He testified that the recovery of depreciation expense on new components installed as part of the Rockport CCT Project through the CCTR would not constitute double recovery, but would recognize a distinct and separate cost. He also explained that I&M is only requesting recovery through the CCTR of the incremental activated carbon expense over the activated carbon expense embedded in base rates. Therefore, there is no potential for double recovery of O&M associated with the ACI System that will occur through the rider recovery mechanism.

C. **Post In-Service Accounting.** Mr. Blakley disagreed with I&M's conclusion that post in-service (deferred accounting) treatment for the CCT is reasonable and necessary. He stated that as the OUCC has testified on several occasions, the OUCC believes that post in-service accounting treatment is not warranted in CWIP trackers. Mr. Blakley stated that it is the OUCC's position that the benefits of the CWIP tracking, which includes a cash return during construction (including equity), more than compensates the utility for any immaterial deferred accounting costs that may be incurred. He testified that the Commission has ruled against post-in-service accounting treatment deferrals unless there is a showing of materiality. He added that in order to show materiality, the utility must show earnings erosion. He said that I&M has not shown that it would suffer material financial earnings erosion without the deferred accounting treatment. Mr. Blakley noted that the Commission denied post in-service AFUDC and deferred depreciation requests in Cause Nos. 43874 and 43956. He recommended the Commission do so here.

Mr. Krawec disagreed with Mr. Blakley. Mr. Krawec explained that the deferral is specifically provided for by the statutes under which I&M sought approval and pointed out that the cases Mr. Blakley relied on involved other statutes. Mr. Krawec explained that the accounting relief I&M seeks has been granted by the Commission for similar CCT projects and is necessary to facilitate full and timely recovery of eligible project costs by I&M. Mr. Krawec disagreed with Mr. Blakley's contention that earnings erosion must be shown and testified that he was not aware of any instance where the Commission imposed this test in a CPCN proceeding for Clean Energy Project or QPCP. Mr. Krawec explained that the post in-service AFUDC proposal is consistent with 170 IAC 4-6-21(b). He also pointed out that Ind. Code ch. 8-1-8.4, the statute under which the OUCC urged the Commission to act in this proceeding, expressly recognizes that post-in-service carrying costs are properly included in the cost recovery.

D. **Ind. Code ch. 8-1-8.4.** Ms. Armstrong agreed that the Rockport CCT Project will significantly reduce Rockport's regulated emissions and assist in meeting new environmental requirements. She stated that the DSI Systems are necessary for I&M to comply with MATS, Clean Air Interstate Rule ("CAIR"), Cross-State Air Pollution Rule ("CSAPR"), and the NSR Consent Decree. She added that the DSI Systems will also reduce fine particulate emissions from the Rockport units and may prevent the facility from having to take additional measures to comply with the new $PM_{2.5}$ NAAQS. Mr. Blakley testified that I&M's Rockport CCT Project falls under the definition of "federally mandated project" in Ind. Code ch. 8-1-8.4 and the OUCC recommended cost recovery for the entire project under this statute. He explained that under this statute, I&M's Rockport CCT Project costs (which includes capital, operating maintenance, depreciation, tax, or financing costs) would be subject to the statute's recovery provision, which allows for recovery of 80% of all approved federally mandated costs through a periodic rate adjustment mechanism. He explained that the remaining 20% of the federally mandated costs should be deferred and recovered by the energy utility as part of its next general rate case. He added that actual costs that exceed the federally mandated costs of the approved project by more than 25% would require specific justification and approval by the Commission before being authorized in the next general rate case filed by the utility.

Mr. Krawec explained his understanding that I&M is permitted to elect which statutory framework to utilize and discussed why I&M's inclusion of an alternative request for relief under Ind. Code ch. 8-1-8.4 was administratively efficient. He pointed out that the OUCC and Industrial Group witnesses did not challenge I&M's testimony showing that the Rockport CCT Project constitutes a Clean Energy Project, CCT, QPCP, and Air Pollution Control Devices. He testified that the Commission has used the statutory framework I&M elected for other environmental compliance proceedings and stated that he was not aware of any reason for I&M to be treated differently for purposes of cost recovery. Mr. Krawec explained that the procedures I&M proposed are known practices already in use and approved by the Commission. He explained why the existing ECR process is better for the utility and customers as compared to initiating a new process. He pointed out differences in the statutory frameworks, including his view that the 20% deferral under Ind. Code ch. 8-1-8.4 includes carrying costs on the complete regulatory asset, including deferred depreciation expense and incremental O&M and the fact that Ind. Code ch. 8-1-8.4 does not expressly provide for ongoing review. Finally, Mr. Krawec described how cost recovery under Ind. Code ch. 8-1-8.4 would occur if this statutory framework were used.

E. **Cost Allocation.** According to Mr. Phillips the appropriate method to allocate fixed costs to the customer classes in the CCTR is the 6 CP method used to allocate fixed production costs to classes approved by the Commission in I&M's most recent base rate case (Cause No. 44075). He testified that use of the 6 CP method reflects the method specified in the 170 I.A.C. 4-6-15 and also reflects the method that the Commission approved to allocate fixed production cost responsibility including QPCP costs to customer classes.

Mr. Krawec agreed with Mr. Phillips and explained that I&M intends to allocate the CCTR costs using the allocation methods approved in Cause No. 44075, which includes the 6 CP method for determining the demand allocation.

F. **Unit 2 Lease.** Mr. Phillips raised a concern regarding the Rockport Unit 2 lease related amounts included in Petitioner's Exhibit SMK-1 Column 1, titled "Indiana Michigan Power Share." He said the Rockport Unit 2 is not owned by I&M and the lease expires in 2022. He said he is not aware of any updates regarding the Rockport Unit 2 lease. Mr. Phillips testified that ratepayers are being asked to pay "up-front" through the CCTR for equipment that may not provide service to them after 2022. He stated that if I&M does not extend the lease on its share of Unit 2, then Indiana ratepayers could end up paying for plant that is not used and useful for the provision of service. Pointing to I&M's proposed 10-year depreciation period, Mr. Phillips testified that if the DSI on Unit 2 has a useful life from 2015 to 2028, then almost half of its useful life may not ever benefit Indiana ratepayers but Indiana ratepayers would pay the full cost of the DSI. He said that without knowing I&M's plans regarding Unit 2, and without having any opportunity to test the reasonableness of I&M's plans for Unit 2, it does not seem reasonable to permit the recovery of Unit 2 costs through the CCTR at this time. He stated that Indiana's share of the I&M lease portion of Unit 2 is about 65% of $70 million (about $46 million). He concluded that the issues regarding Rockport Unit 2 are complex and not adequately explained by I&M. He contended that ratemaking for Rockport Unit 2 is beyond the scope of a tracker proceeding and requires a separate proceeding or a base rate case similar to the ratemaking associated with the purchases from AEP Generating Company ("AEG"). He recommended that the Commission require that I&M present for approval its plans for Unit 2, and to demonstrate that the costs of the proposed project for Unit 2 are reasonable in light of that plan if approved, prior to allowing the inclusion of the associated cost in the CCTR. He said it may well be that the Commission would find that the project and cost are not reasonable, or that only a portion of the costs are recoverable if the project life exceeds the time I&M will receive power from the facility.

Ms. Hawkins discussed the lease renewal options and treatment of environmental capital under the Rockport Unit 2 lease agreement. Ms. Hawkins acknowledged the prior testimony in Cause No. 44033 stating that I&M and AEG were actively evaluating the options of renewing, terminating, or buying out the Rockport Unit 2 lease and had then expected to reach a decision by the end of 2011. She indicated that thereafter the discussions with the lessors were held in abeyance while discussions took place regarding the use of DSI at Unit 2. She said the lessors are aware of the modification of the NSR Consent Decree. She said discussions will likely resume at a later time. She explained that while I&M's economic analysis reflected the highest renewal cost, I&M has the ability to select the lower of either continuing its current rental rate or paying a fair market value rate. So if I&M is able to renew at a lower fair market value rate, the benefits of the plan will only be higher than what is currently presented in this case. She noted that I&M cannot give notice under a fixed rate option until December 2017 and notice is not required until 2021. She commented that although I&M may desire to negotiate with the lessors prior to these dates, I&M cannot compel the lessors to execute a renewal term prior to these dates. She said the required dates for the renewal are far past when the DSI equipment must be added to the units. Ms. Hawkins also discussed the lease provisions that would require the lessors to purchase the DSI equipment at fair market value if the lease is not renewed and the lessors continue to operate Unit 2. Ms. Hawkins clarified that I&M is not requesting that the full cost of these assets be depreciated over the remaining life of the lease. Rather, I&M proposes the equipment to be depreciated over 10 years. She said this proposal reasonably balances the possibility that the lease will not be extended with the potential that the lease will be renewed for the balance of the ten-year period, if not beyond that point in time.

Mr. Weaver explained how the analysis set forth in his direct testimony permits us to better understand the implications of future disposition options, including the possibility that the Unit 2 lease would not be renewed beyond the current 2022 term. He explained that the economic analysis shows that the decision to install the Rockport CCT Project on Unit 2 is reasonable and cost effective even under the possible scenario where the lease is not renewed beyond the end of the current term in 2022. He noted that if the Rockport CCT Project is not installed on Unit 2, the unit could not continue to operate under the MATS Rule. Mr. Weaver added that the alternative to performing the DSI project on Rockport Unit 2 is to retire the unit. He stated that the incremental cost for the period 2015 through 2022 to replace the capacity and energy from Rockport Unit 2 far exceeds the incremental fixed, variable and carrying cost of installing and operating the unit with DSI.

Mr. Krawec testified that while the future of the Unit 2 lease beyond 2022 may be dependent on events that have yet to occur, he disagreed that the ratemaking issues are complex. He also disagreed that I&M's capital investment should be denied the ratemaking and accounting treatment applicable to other Clean Energy Projects and QPCP during the period the projects are under construction and in service. He explained that I&M's environmentally related capital investment in Rockport Unit 2 has been reflected in rate base and depreciation expense.

Therefore, I&M earns a return on and of such investment. He explained that the Rockport Plant is currently used and useful and is expected to remain so until the end of the original lease term, if not beyond. He said the Rockport CCT Unit 2 Project will also be part of this used and useful facility at least until the end of the lease term, if not beyond. He stated that there is no need to speculate in this proceeding about possible future lease issues, including the possible return of Rockport Unit 2 to the lessors and the future of the installed DSI Systems. He added that these future issues are more appropriately addressed at the time a decision is made regarding Rockport Unit 2. He testified that for purposes of I&M's requested relief in this matter, I&M should not be penalized from earning a return on its capital investment, incremental O&M and depreciation for used and useful property via the CCTR.

Mr. Krawec discussed the possibility that the lease would not be renewed and indicated that I&M would advise the Commission of such matters and make a proposal to address issues regarding the remaining undepreciated balance of the Rockport CCT Project equipment. Mr. Krawec also explained I&M's proposed treatment if the lease is not extended and the lessors choose to purchase the Rockport DSI equipment. He explained that to the extent the fair market value paid to I&M exceeds I&M's net book value for the DSI equipment, I&M would record a regulatory liability for the difference to be returned to Indiana jurisdictional customers in a future rate proceeding. Conversely, to the extent the fair market value paid I&M is less than I&M's net book value for the DSI equipment, I&M would record a regulatory asset for the difference to be recovered from Indiana jurisdictional customers in a future rate proceeding.

G. __New Cause Number__. To help eliminate possible confusion, Mr. Blakley recommended a new Cause number for the new ECR tracker for the Rockport CCT project. The new tracker should be Cause No. 44331 ECR X.

Mr. Krawec testified that I&M has no objection to using a new cause number.

7. **__Testimony in Support of Settlement Agreement.__**

A. **__I&M's Evidence.__** Mr. Lewis explained that the other parties did not challenge the need for or the estimated cost of the Rockport CCT Project. He explained that the OUCC and Industrial Group raised concerns in this docket primarily regarding ratemaking treatment. The Parties discussed the issues and negotiated a resolution of these concerns in the Settlement Agreement and that from I&M's perspective the proposed resolution is a reasonable part of the comprehensive settlement package. He said that the cost of the Rockport CCT Project, while significant, is substantially less than the cost of the DFGD project proposed in Cause No. 44033. He stated that the construction schedule is also shorter.

Mr. Lewis explained why the estimated capital cost in the Settlement Agreement differs from that presented in I&M's case-in-chief. He testified that the total estimated capital cost presented in I&M's case-in-chief reflected the Phase I cost estimate and the Preconstruction Costs which I&M included in the Rockport CCT Project capital costs in accordance with GAAP and the USOA. He said the Settlement Agreement reflects the Phase II capital cost estimate and Preconstruction Costs, which are more refined and certain and $26.7 million lower than the Phase I cost estimate.

Mr. Lewis further testified that there are four components of the estimate that have been updated. He said the updates include a $4,923,000 reduction in the direct cost of the modifications needed on the dry sorbent injection and activated carbon injection system, an increase of $1,074,000 in internal labor costs, a reduction of $4,585,000 in the amount allocated for AEP overheads, and a reduction of $18,250,000 in the amount allotted for risk allocation. He explained that these updated components have reduced the overall cost estimate for the Rockport CCT Project (excluding Preconstruction Costs) from a total cost of $240,710,000 to $214,026,000. He stated that the changes to the first three components were based on the receipt of updated information from external and internal sources as time and the percentage of the project complete has progressed. He also discussed the updated risk analysis that resulted in the reduction in the amount allotted for risk allocation.

He explained that the Range Estimate Risks and Risk Events evaluate issues the Project might encounter and the probability of occurrence and cost associated with them. He explained that in the updated exhibit, the amount of the project cost subject to risk that the Project has mitigated during the Phase II design evolution and contracting processes performed since I&M's original filing date on April 15, 2013 has increased by approximately $58,500,000 (from $56,112,169 to $114,675,940). He explained that with the additional information, I&M and AEPSC have reduced the probability and values associated with the occurrence of specific events, which further mitigated a portion of the initial project risk. Mr. Lewis explained that I&M considered the Phase II cost estimate to be closer to the +/- 10% range. He clarified that significant engineering and other work remains. He said the Phase II cost estimate is the latest information derived from I&M's phased approach to construction projects. He stated that I&M will strive to construct the Rockport CCT Project within this updated cost estimate. He added that as provided in Paragraph 6(i) of the Settlement Agreement Terms and Conditions, should construction costs exceed this amount by more than 25%, the costs above the 25% will be presented by I&M with specific justification and considered for ratemaking treatment by the Commission in I&M's next applicable general base rate case(s).

Mr. Lewis also addressed the concerns about the Unit 2 lease. He stated that Mr. Phillips challenged I&M's cost recovery proposal for the Rockport Unit 2 costs on the grounds that it is possible that the Rockport 2 lease may not be renewed after the end of its current term in 2022. He added that Ms. Hawkins, Mr. Krawec, and Mr. Weaver addressed this issue in their rebuttal. Mr. Lewis testified that Paragraph 6(j) sets forth the Parties' agreed resolution of this matter. He said this Paragraph provides that except for Preconstruction Costs, I&M will be authorized to depreciate the Indiana Retail Jurisdictional Share of I&M's Direct Ownership Share of the Rockport CCT Project utilizing a 10-year life. He explained that the balance of Paragraph 6(j) addresses the ratemaking treatment of the Rockport CCT Project costs attributable to Unit 2 if the Rockport Unit 2 lease is not renewed beyond the end of its current term in 2022. He stated that this Paragraph provides that notwithstanding the provision regarding the agreed depreciation period, in the event the Rockport Unit 2 lease is not renewed beyond the end of its current term in 2022 and I&M is no longer using the asset, then no later than six months prior to the expiration of the lease, I&M will file a petition with the Commission for approval of I&M's proposal regarding any accounting and ratemaking issues associated with wrapping up the Rockport CCT Project costs and attributes attached to Unit 2 and the ongoing nature of the prospective cost recovery. He noted that the Settlement Agreement further provides that this provision is without waiver of each Party's respective rights to make arguments in such subsequent proceeding regarding the recoverability, accounting and ratemaking for such Unit 2 costs, including the right to propose or oppose the recovery of such costs through the Federal Mandate Rider on a subject to refund basis pending the outcome of such proceeding.

Mr. Lewis explained that from I&M's perspective, the Unit 2 Rockport CCT Project is reasonable even if the lease is not renewed beyond the end of its current term. He noted that this view was discussed in I&M's rebuttal testimony. He stated that while I&M's witnesses explained why I&M disagreed with Mr. Phillips' recommendation, the negotiated compromise reasonably resolves this issue. He stated that the Settlement Agreement permits the CCT Project to be constructed and used on Rockport Unit 2 within the time frame needed to comply with the MATS Rule and avoids the need for the Commission to decide today a matter that may be easier to resolve once the future of the lease is known.

Mr. Lewis testified that the Rockport CCT Project is a cost-effective means of maintaining the availability of relatively low cost, coal-fired generation that complies with environmental regulations, allows the plant to continue to serve customer needs, provides jobs and tax revenues to the community, and does so in a manner that mitigates the rate impact on customers. He concluded that approval of the Settlement Agreement will allow I&M to continue to have economic generation from the Rockport Plant available to serve I&M's customers while complying with Federal environmental regulations at a significantly lower cost than previously contemplated, which is, in his opinion, in the best interest of the public.

Mr. Krawec explained that Exhibit SMK-1 (Updated) attached to the Settlement Agreement depicts how the total estimated cost of the capital investment for Units 1 and 2 flows through the ownership and capacity obligation structure of the Units to I&M on a Total Company basis and on an Indiana Retail Jurisdictional basis.

Mr. Krawec discussed Paragraph 3 of the Settlement Agreement, which provides that the total estimated capital cost (excluding AFUDC) for the Rockport CCT Project in the amount of $258,052,000. He stated that Paragraph 3(a) clarifies that the Rockport CCT Project updated capital cost estimate in the amount of $258,052,000 is a total cost. As also shown on Exhibit SMK-1 (Updated), he said this cost is shared by I&M, AEG, and I&M's sister company, Kentucky Power. He testified that this Paragraph recognizes that the costs allocated to Kentucky Power are not part of this proceeding. Rather, this proceeding and the Settlement Agreement concern I&M's "Direct Ownership Share" and "I&M's Allocated Share" of the total estimated capital costs allocated to I&M via I&M's purchases from AEG. He said these terms, which line up with the columns shown on Exhibit SMK-1 (Updated), are used to facilitate an understanding of the agreement regarding the ratemaking for the project costs.

Mr. Krawec also explained that the Preconstruction Costs, *i.e.,* the costs incurred in pursuing the installation of a DFGD on one unit at the Rockport Plant, are included in the total estimated capital cost of the Rockport CCT Project. Mr. Krawec explained that Paragraph 3(c) identifies I&M's Direct Ownership Share of the total estimated capital costs to be $129,026,000 (Total Company and excluding AFUDC) and stated that this amount includes an estimated $22,013,000 in Preconstruction Costs. He stated that Paragraph 3(d) identifies I&M's Allocated Share of the total estimated capital costs of the Rockport CCT Project is estimated to be $90,318,000 (Total Company).

Mr. Krawec explained that in this case the OUCC and I&M witnesses filed testimony proposing different approaches to timely cost recovery. He said I&M proposed to utilize the cost recovery currently in place in I&M's ECR proceedings and Mr. Blakley recommended the Commission utilize the cost recovery provisions set forth in Ind. Code ch. 8-1-8.4. Mr. Krawec stated that Ind. Code ch. 8-1-8.4 provides for timely recovery of 80% of costs through a tracker while 20% of costs are deferred and recovered in a subsequent base rate case. Mr. Krawec noted that in his rebuttal testimony he explained why I&M disagreed with the OUCC proposal to use this 80/20 cost recovery. He added that the Settlement Agreement resolves the issue by accepting the OUCC proposal to utilize Ind. Code ch. 8-1-8.4 for 80/20 recovery as set forth in the Settlement Agreement.

Mr. Krawec explained that Paragraph 3(f) spells out the agreement regarding I&M's Allocated Share of the Rockport CCT Project costs. He stated that this Paragraph provides that these costs will be recovered in subsequent I&M general rate cases. He added that to the extent I&M's Allocated Share is no more than the estimated costs described herein, then the prudence of such expenditures shall not be subject to challenge other than as contemplated by Paragraph 6(j). He stated that I&M's Allocated Share represents 70% of AEG's share of the total cost of the Rockport CCT Project, which AEG will bill monthly to I&M through the Rockport Unit Power Agreement.

Mr. Krawec explained that Paragraph 3(g) of the Settlement Agreement quantifies the Indiana Retail Jurisdictional Share of I&M's Direct Ownership Share (including the Preconstruction Costs). He said this Paragraph provides that the Indiana Retail Jurisdictional Share of such costs will be determined using the jurisdictional demand allocation factor approved by the Commission in I&M's general rate cases. He noted that to facilitate a better understanding of this provision, the Settlement Agreement sets forth an illustrative calculation based on the jurisdictional demand allocation factor approved in I&M's most recent general rate case (Cause No. 44075). He noted that the Indiana Retail Jurisdictional allocation factors may be reviewed and updated in I&M's subsequent general rate cases, and correspondingly the Indiana Retail Jurisdictional share of I&M's Direct Ownership Share will also be updated.

Mr. Krawec explained that Paragraph 3(h) is similar to Paragraph 3(g) in that Paragraph 3(h) quantifies the Indiana Retail Jurisdictional Share of the Preconstruction Costs reflected in I&M's Direct Ownership Share. He explained that while there was no dispute among the Parties regarding the quantification of this amount, OUCC witness Blakley raised a challenge to I&M's proposal to earn a return on this amount as it is being recovered. He said Paragraph 3(h) sets forth the Parties' negotiated resolution of this issue. He stated that this Paragraph provides that without waiver of the Parties' positions regarding the eligibility of said Preconstruction Costs for cost recovery and solely for purposes of compromise, the Parties agree that the Indiana Retail Jurisdictional Share of the Preconstruction Costs will be amortized and recovered under Ind. Code ch. 8-1-8.4 over the remaining life of the Rockport facility and that the Preconstruction Costs, along with the remaining Indiana Retail Jurisdictional Share of I&M's Direct Ownership Share will earn a return based on I&M's weighted average cost of capital as provided in the Settlement Agreement. He stated that the expected retirement date for Rockport Unit 1 and common facilities used to determine the depreciation rates approved in I&M's most recent base rate case (Cause No. 44075) is December 2044, which equates to a 29-year recovery period for the Preconstruction Costs (2015-2044).

Mr. Krawec noted that the Settlement Agreement also addresses the concern raised by Ms. Armstrong regarding the possibility that certain activated carbon expense embedded in the revenue requirement used to establish I&M's base rates would be "double recovered" through the timely recovery through the tracker of the Rockport CCT Project O&M costs, depreciation, and tax expense. He stated that Paragraph 4 of the Settlement Agreement recognizes that I&M may incur incremental O&M costs (including consumables), depreciation, and tax expense over and above the amount embedded in I&M's base rates. He said this Paragraph provides that such costs will be recovered under Ind. Code ch. 8-1-8.4 as provided for in this Settlement Agreement if reasonable and necessary.

Mr. Krawec testified that Paragraph 6 sets forth how cost recovery under Ind. Code ch. 8-1-8.4 will be implemented. He explained that this provision discusses the 80% timely cost recovery and the 20% deferred cost recovery consistent with Ind. Code ch. 8-1-8.4. He stated that in Paragraph 6(a), the Settlement Agreement provides that eighty percent (80%) of the Federally Mandated Costs shall be recovered in a timely manner through a Federal Mandate Rider including: a carrying charge at the overall weighted average cost of capital (weighted average rate of return) on capital costs/expenditures and Preconstruction Costs during construction and after a project is placed in service, operating and maintenance (including consumables), depreciation, tax, financing costs, and post in-service AFUDC on capital costs and Preconstruction Costs. He said that consistent with Paragraphs 6 and 6(f) of the Settlement Agreement, during construction, I&M will continue to accrue AFUDC on its share of the entire project cost until such time as the Federal Mandate Rider is authorized to recover a carrying charge at the overall weighted average cost of capital on CWIP and Preconstruction Costs. He stated that at that time, AFUDC will cease on 80% of the CWIP amount and 80% of the Preconstruction Costs, and the carrying charge above will be recovered through the Federal Mandate Rider until the Rockport CCT Project amounts are in-service.

Mr. Krawec also discussed the new Federal Mandate Rider included with his settlement testimony. He explained that I&M may file its first Federal Mandate Rider proceeding within three months of a final Commission Order approving this Settlement Agreement. He stated that while Ind. Code ch. 8-1-8.4 is silent regarding the requirement of a six-month construction period to precede the rate recovery through a rider, I&M is confident that the Rockport CCT Project will be under construction for more than six months at the time the initial rider factors are approved, and I&M will reflect this in its forecast used to derive its first set of proposed rider factors. Mr. Krawec explained that I&M will request updates to its Federal Mandate Rider in six-month intervals with the factors established under the Rider remaining in place until superseded by updated factors. I&M will be authorized to defer and record as a regulatory asset 80% of its post-in-service depreciation, incremental O&M expense (including consumables), property tax, and post-in-service AFUDC on capital costs related to the Rockport CCT Project until the Commission approves ratemaking treatment through the Federal Mandate Rider with any resulting variances reconciled in subsequent Rider filings. Mr. Krawec testified that the proposed treatment of the 80% recovery of the federally mandated costs is nearly identical to the treatment afforded for timely recovery of costs and expenses through I&M's CCTR.

Mr. Krawec explained that Paragraph 6(b) provides that the twenty percent (20%) of the Federally Mandated Costs that will be deferred until rates are established in subsequent I&M general rate cases includes: AFUDC on capital costs during construction and Preconstruction

Cost, post in-service AFUDC on capital costs and Preconstruction Costs, and, after the project is placed in service, operating and maintenance (including consumables), depreciation, and taxes. He added that as stated in Paragraph 6(h) the 20% cost recovery allowed under the Ind. Code ch. 8-1-8.4 will be deferred for recovery in I&M's next general rate case. I&M will continue to accrue AFUDC on 20% of the CWIP amount and 20% of the Preconstruction Costs until the Rockport CCT Project is in service. He noted that after the Rockport CCT Project is placed in service, normal AFUDC will cease and I&M will defer post in-service AFUDC on 20% of the capital costs and Preconstruction Costs, and 20% of the depreciation, incremental O&M (including consumables), and property tax expense, until rates are established in a subsequent I&M general rate case. He stated that the deferred amounts will be charged to FERC Account 182.3, Other Regulatory Assets, and will be amortized over the remaining life of the Rockport CCT Project when reflected in a subsequent general rate case.

Mr. Krawec explained that consistent with the Settlement Agreement, the 80% recovery through the Federal Mandate Rider uses the same structure currently in place for timely recovery of costs and expenses through I&M's CCTR. He testified that through the CCTR, I&M received timely cost recovery of its QPCP at its Rockport and Tanners Creek Plants in the form of a carrying charge at the overall weighted cost of capital on CWIP amounts and post-in-service AFUDC until the CCTR provided a carrying charge on the in-service investment, depreciation expense, and operation and maintenance (including consumables) expense. He added that consistent with the CCTR, the Federal Mandate Rider will calculate the monthly carrying charge on 80% of the net amount in service. He said this will automatically reduce net in-service amounts by the monthly depreciation amounts recovered through the Federal Mandate Rider, resulting in a reduced monthly carrying charge on the Rockport CCT Project capital costs. Mr. Krawec noted that the resolution of the implementation details in the Settlement Agreement was important to I&M's decision to accept cost recovery under Ind. Code ch. 8-1-8.4. He explained that mirroring the cost recovery of the 80% of Federally Mandated costs with the CCTR recovery avoids potential disputes about how such cost recovery will occur. He added that I&M did not want to resolve the cost recovery issues in this case by simply deferring all the details to the future rider proceedings.

Mr. Krawec testified that consistent with Mr. Blakley's recommendation and Mr. Krawec's rebuttal testimony, the Settlement Agreement provides that the Federal Mandate Rider will be established as a new case number, such as Cause No. 44331 ECR X. He contemplates that the exhibits, schedules, and workpapers associated with the tracking of the 80% of federally mandated costs will follow the same structure currently used for ECR proceedings under I&M's CCTR. He added that by using a structure that is consistent with that already in place, the Settlement Agreement should permit the timely cost recovery under Ind. Code ch. 8-1-8.4 to be implemented in an efficient manner.

Mr. Krawec testified that as is the case with I&M's existing ECR proceedings, the Settlement Agreement provides that I&M will be authorized to add to the value of I&M's property for ratemaking purposes 80% of the value of the Indiana Retail Jurisdictional Share of I&M's Direct Ownership Share of the total Rockport CCT Project capital costs (including Preconstruction Costs) in accordance with the Commission's construction work in progress ratemaking rules. He stated that pursuant to 170 IAC 4-6-21, I&M shall add the approved return to its net operating income authorized by the Commission for purposes of Ind. Code § 8-1-2-

42(d)(3) in all subsequent fuel adjustment charge proceedings, prorated for the effective period of the approved rates.

Mr. Krawec stated that the Federal Mandate Rider will have a reconciliation process. He stated that the Settlement Agreement provides that I&M will be authorized to defer and record as a regulatory asset post-in-service depreciation, incremental O&M expense (including consumables), tax and post-in-service AFUDC on capital costs until the Commission approves ratemaking treatment through the Federal Mandate Rider with any resulting variances reconciled in subsequent Rider filings. He said I&M expects to file its first reconciliation along with its third rider update request filing. Subsequently, reconciliation will be included in every rider update request filing. He said this reconciliation schedule will allow the first reconciliation to include a full term (*i.e.* 6 months) where the initial rider rates were in effect.

Mr. Krawec explained that Paragraph 6(i) relates to a provision in Ind. Code ch. 8-1-8.4, namely Ind. Code § 8-1-8.4-7(c)(3). He said, this Paragraph provides that in the event the actual construction costs (excluding AFUDC) exceed the projected federally mandated costs of the Rockport CCT Project by more than twenty-five percent (25%), then the Indiana Retail Jurisdictional Share of I&M's Direct Ownership Share of the Rockport CCT Project costs above the 25% will be presented by I&M with specific justification and considered for rate recovery by the Commission in I&M's next applicable general rate case. He added that the total Rockport CCT Project cost (excluding AFUDC) would have to exceed $322,565,000 ($258,052,000 x 125%) to trigger the "25%" rule. In response to the Commission's Docket Entry dated August 2, 2013, I&M explained that the phrase "Federally Mandated costs" was used in Section 6(i) to incorporate statutory language from Ind. Code § 8-1-8.4-7(c)(3). I&M added that the words "actual construction costs" were used in this provision of the Settlement Agreement to clarify what cost would be reflected in the comparison. Further, later in Paragraph 6(i) the Federally Mandated costs used for this comparison are defined as "Indiana Retail Jurisdictional Share of I&M's Direct Ownership Share of the Rockport CCT Project costs", which limits the Federally Mandated costs for this purpose to just the construction costs and Preconstruction Costs.

Mr. Krawec stated that Mr. Phillips recommended that the allocation method approved in I&M's most recent base rate case, Cause No. 44075, be used as the allocation of the CCTR costs to the customer classes. Mr. Krawec noted that he agreed with this recommendation in his rebuttal testimony. He said the Settlement Agreement accepts Mr. Phillips's recommendation by providing that the allocation of costs in the Federal Mandate Rider will be based on the allocation methods approved by the Commission in I&M's base rate case (Cause No. 44075), which includes the 6 CP method for determining the demand allocation.

Mr. Krawec testified that Paragraph 6(j) provides that except for Preconstruction Costs, I&M will be authorized to depreciate the Rockport CCT Project utilizing a 10-year life. He said Paragraph 3(h) explains that Preconstruction Costs will be amortized and recovered under Ind. Code ch. 8-1-8.4 over the remaining life of the Rockport facility. He explained that Exhibit SMK-1 was revised to reflect that the depreciation period for Preconstruction Costs in the Settlement Agreement is 29 years (estimated remaining life of Rockport when DSI is placed in service) and not the 10-year period applicable to the rest of the Rockport CCT Project. He said this exhibit is otherwise the same as the one originally attached to the Settlement Agreement.

Mr. Krawec concluded that the Settlement Agreement including Exhibit SMK-1 (Updated Revised) reduces the estimated impact of the Rockport CCT Project on Indiana retail jurisdictional revenues at the end of the project from approximately 3% to approximately 2.6%.

B. OUCC's Evidence. Mr. Blakley explained that the total estimated cost for the Rockport CCT Project in the settlement, excluding AFUDC, is $258,052,000. He said I&M's Direct ownership of the Rockport CCT project is 50%, making its allocated share of the Project $129,026,000. He added that applying the Indiana Retail Jurisdictional factor of 64.65519% (approved in I&M's last general rate case in Cause No. 44075) results in an Indiana Retail Jurisdictional share of the Rockport CCT investment of $83,422,005. He noted that the amount is less than I&M originally requested but added that the reduced amount is not as a result of the settlement. He stated that after I&M received more detailed engineering and construction information, it was able to reduce the amount of risk contingency it was requesting for the Rockport CCT Project. He said this resulted in a reduction to the cost estimate, which represents a savings benefit to Indiana consumers.

Mr. Blakley explained that the Parties have agreed to the method of cost recovery for the Rockport CCT Project. He said the Rockport CCT Project is defined as a CCT project under Ind. Code chs. 8-1-8.7 and 8-1-8.8 and §§ 8-1-2-6.7 and 8-1-2-6.8. He said the Parties have also agreed that the Rockport CCT Project, including O&M and depreciation costs, also qualifies for cost recovery as a federally mandated project under Ind. Code ch. 8-1-8.4. He added that the Parties have agreed that the calculation of a CWIP return for the Rockport CCT Project will be governed under the Commission's rules in 170 IAC 4-6, which spells out the treatment of construction investment and the calculation of the weighted cost of capital. He said the Rockport CCT Project fits the definition of a "federally mandated" project because I&M has to complete this Project in order to for it to be in compliance with the MATS Rule.

Mr. Blakley explained that a primary feature of Ind. Code § 8-1-8.4 is the 80/20 split for cost recovery. He testified that I&M will be able to recover 80% of all approved federally mandated costs through a periodic retail rate adjustment mechanism, which will be a CWIP tracker. He stated that during the Rockport CCT Project construction, I&M will request an update to this tracker every six (6) months with 80% of the current construction costs. He stated that a return will be calculated on this and together with other costs as set forth in the Settlement Agreement will be billed out to the customers through the tracker. Mr. Blakley stated that the other 20% of these costs will be deferred, accrue AFUDC, and be recovered as part of I&M's next general rate case. He added that when the Project is completed, 80% of the construction costs net of accumulated depreciation will have a return calculated and tracked, and also 80% of related depreciation expense and O&M expenses will flow through this CWIP tracker. He said the 20% deferred will include post-in-service AFUDC on the construction costs. He stated depreciation expense and operation and maintenance expenses will be deferred for 20% of the costs without carrying charges until the time of the next rate case.

He explained that the 80% limitation on cost recovery in the CWIP trackers that falls under the federally mandated requirement statute gives immediate rate relief to customers because 80% of the costs, not 100%, are tracked to customers. He testified that the customers have the benefit of lower bills, while I&M benefits from the cash return before the Project is used and useful, plus the recovery of 80% of its other costs once the Project is used and useful.

I&M also benefits from the ability to defer 20% of costs until the next rate case. He said customers will eventually pay for these deferrals when they are included for recovery in I&M's next rate case.

Mr. Blakley testified that if the Rockport Unit 2 lease is not renewed beyond the end of its current term in 2022 and I&M is no longer using an asset, then I&M must file a petition with the Commission no later than six months prior to its expiration. He said this petition will address the accounting and ratemaking issues associated with the Rockport CCT Project costs attached to Unit 2 and the treatment of any future cost recovery. In his view, this term will help ensure the ratepayers do not continue to pay for an asset that may no longer be used for the benefit of I&M customers.

Mr. Blakley concluded that he believes the Settlement Agreement is in the public interest. He said the agreement addresses the OUCC's concerns with revenue requirements issues and it will result in reduced overall ratepayer financial impact.

8. Commission Discussion and Findings.

A. Settlement Policy. Settlements presented to the Commission are not ordinary contracts between private parties. *United States Gypsum, Inc. v. Indiana Gas Co.*, 735 N.E.2d 790, 803 (Ind. 2000). When the Commission approves a settlement, that settlement "loses its status as a strictly private contract and takes on a public interest gloss." *Id.* (quoting *Citizens Action Coalition of Ind., Inc. v. PSI Energy, Inc.*, 664 N.E.2d 401, 406 (Ind. Ct. App. 1996)). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action Coalition*, 664 N.E.2d at 406.

Further, any Commission decision, ruling, or order – including the approval of a settlement – must be supported by specific findings of fact and sufficient evidence. *United States Gypsum*, 735 N.E.2d at 795 (citing *Citizens Action Coalition of Ind., Inc. v. Public Service Co. of Ind., Inc.*, 582 N.E.2d 330, 331 (Ind. 1991)). The Commission's own procedural rules require that settlements be supported by probative evidence. 170 IAC 1-1.1-17(d). Therefore, before the Commission can approve the Settlement Agreement, we must determine whether the evidence in this Cause sufficiently supports the conclusions that the Settlement Agreement is reasonable, just, and consistent with the purpose of Indiana Code ch. 8-1-2, and that such agreement serves the public interest.

B. Ind. Code ch. 8-1-8.4. The parties agreed that I&M would seek approval of the CPCN and cost recovery for the Rockport CCT Project under Ind. Code ch. 8-1-8.4. Prior to issuing a CPCN under Ind. Code § 8-1-8.4-6, we must consider the following factors: (1) the federally mandated requirements, including any consent decrees related to the federally mandated requirements, that the proposed project will allow the utility to comply with; (2) the costs associated with the proposed project; (3) whether the proposed project will allow the utility to comply with the federally mandated requirements; (4) alternative plans that demonstrate that the proposed project is reasonable and necessary; (5) whether the proposed project will extend the useful life of an existing utility facility and the value of that extension; and (6) any other factors we consider relevant. Ind. Code § 8-1-8.4-7(b)(3). In addition, we must make a finding that public convenience and necessity will be served by the proposed project, Ind. Code § 8-1-2-8.4-7(b)(1), and approve the projected federally mandated costs associated with the project, Ind. Code § 8-1-2-8.4-7(b)(2).

1. **Federally Mandated Requirements.** Mr. Chodak presented evidence about the NSR Consent Decree. On December 10, 2007, AEP entered into the Consent Decree with the EPA related to the NSR provisions of the CAA. The Consent Decree included an agreement that I&M would retrofit SCR and FGD on Rockport Units 1 and 2. I&M later discovered a more cost-effective solution for compliance with the Consent Decree and negotiated a modification to the Consent Decree to allow I&M to construct the Rockport CCT Project as an alternative to the required SCR and FGD projects. In addition, Mr. Hendricks presented testimony about the MATS Rule. The MATS Rule contains stringent emission rate limitations for several HAPs, including HCl.

Based on the evidence presented, we find that the MATS Rule represents a federally mandated requirement as that term is defined in Ind. Code § 8-1-8.4-5. Therefore, we find that I&M has complied with the requirements of Ind. Code § 8-1-8.4-6(b)(1)(A). Because we find that the MATS Rule is sufficient to allow I&M to seek cost recovery under Ind. Code ch. 8-1-8.4, we do not address whether the Consent Decree or its underlying environmental compliance obligations qualify as a federally mandated requirement as defined in Ind. Code § 8-1-8.4-5.

2. **Projected Costs.** Mr. Chodak, Mr. Walton, and Mr. Krawec presented testimony and exhibits regarding the project costs and explained how the total costs of the Rockport CCT Project flowed through the ownership structure, lease and purchase agreement between I&M and AEG. Mr. Snyder testified that he reviewed the cost estimate and recommended approval of the Project.

The estimated capital cost for the Rockport CCT Project reflected in the Settlement Agreement is $258,052,000 of which I&M's Direct Ownership Share is $129,026,000 (excluding AFUDC but including $22,013,000 in Preconstruction Costs). The Settlement Agreement reflects the Phase II capital cost estimate and Preconstruction Costs, which are more certain and $26.7 million less than the Phase I cost estimate that I&M proposed in its case-in-chief evidence. The Settlement Agreement and supporting evidence delineate I&M's Direct Ownership Share and I&M's Allocated Share of the total estimated capital costs of the Rockport CCT Project. The Project does not involve regional transmission expansion costs.

Based on the evidence presented, we find that I&M has adequately described the projected federally mandated costs associated with the Rockport CCT Project, including costs that are allocated to the energy utility in compliance with Ind. Code § 8-1-8.4-6(b)(1)(B).

In the Settlement Agreement, the parties agreed that the total estimated capital cost of the Rockport CCT Project is reasonable. The evidence presented shows that the Rockport CCT Project is a cost-effective means of complying with the MATS Rule, and that the estimated cost of the project is significantly less expensive than other considered alternatives. The parties also agreed to include the Preconstruction Costs from the REP in the estimated capital costs of the Rockport CCT Project. Mr. Chodak testified that the Preconstruction Costs are reasonable because I&M had to move forward with a plan to ensure the Rockport Plant would be available for generation because it was not yet sure whether DSI would be cost effective, technologically feasible, or a legally allowed environmental compliance measure. Based on the evidence, we find that I&M took reasonable steps to insure it could achieve MATS compliance through the REP while it explored the possibility of alternative solutions. We find that the estimated capital costs of the Rockport CCT Project, including the Preconstruction Costs, are reasonable. Therefore, we approve the projected federally mandated costs associated with the Rockport CCT project as required by Ind. Code § 8-1-8.4-7(b)(2).

3. **Compliance with Federally Mandated Requirements.** Mr. Hendricks presented evidence that the Rockport CCT project will limit the emission of SO_2 and HCl, which will enable Rockport Units 1 and 2 to be operated in compliance with the MATS Rule. Both the OUCC and the Industrial Group presented evidence agreeing that the Rockport CCT project will allow I&M to comply with the MATS Rule.

Based on the evidence presented, we find that the Rockport CCT project will allow I&M to comply with the MATS Rule as required by Ind. Code § 8-1-8.4-6(b)(1)(C).

4. **Alternative Plans for Compliance.** Mr. Chodak discussed the efforts undertaken by I&M to explore alternatives and identify a cost-effective means to comply with the MATS Rule. Mr. Walton discussed AEP's experience with DSI technology through pioneering and developing and then patenting the use of a dry sorbent for removal of sulfur trioxide, an acid gas. I&M performed analyses showing that the Rockport CCT Project is the most cost effective option for compliance with the MATS Rule.

Mr. Weaver's analysis set forth the relative cost and feasibility of a Rockport Unit 1 and 2 retirement option and demonstrated that the cost of that alternative would likely significantly exceed that of the proposed Rockport CCT Project. Mr. Weaver's analysis in his direct testimony also showed that the dispatch priority of the proposed environmentally-controlled Rockport units will not be adversely impacted based on the resulting variable cost profiles within the economic analyses described above. It would be anticipated that the units' annual capacity factor will not be significantly different from historical levels after these retrofits are installed. Accordingly, the record shows that the Rockport CCT Project is not expected to significantly change the dispatching order of the units.

Mr. Rutter also investigated whether there are viable alternatives to the Rockport CCT Project and concluded that the Rockport CCT Project is a reasonable balance of costs, risks and policy based on a retrofit approach to meeting the requirements of the MATS Rule.

Based on the evidence presented, we find that I&M considered several alternative plans for compliance with the federally mandated requirements, in addition to the SCR and FGD projects originally required by the Consent Decree. The evidence demonstrates that the Rockport CCT Project is a cost-effective method to achieve compliance with the MATS Rule. Therefore, we find that the alternative plans demonstrate that the project is reasonable and necessary as required by Ind. Code § 8-1-8.4-6(b)(1)(D).

5. **Useful Life of the Facility.** The record reflects that due to the need to comply with the MATS Rule emission limits, I&M would be forced to shut down both

Rockport Units absent the proposed retrofit. The record reflects that the installation of the Rockport CCT Project will preserve, if not extend, the remaining lives of the Rockport Units. Therefore, based on the evidence we find that I&M has demonstrated that the Rockport CCT Project will extend the useful life of Rockport Units 1 and 2, as required by Ind. Code § 8-1-8.4-6(b)(1)(E).

6. **Public Convenience and Necessity.** As our discussion above demonstrates, I&M put significant work into identifying a cost-efficient method of complying with the MATS Rule and the Consent Decree. Since the filing of its case-in-chief, I&M undertook further work on the project and was able to complete the Phase II cost estimate, which further reduced the projected costs being sought for recovery in this Cause. The cost estimate set forth in the Settlement Agreement reflects the Phase II cost estimate and the Preconstruction Costs. The record reflects that the updated Phase II cost estimate would be categorized as a Class 1 estimate by the AACE. Mr. Lewis testified that the Phase II cost estimate is based upon 60% of the engineering having been completed and approximately 40% of the overall project now under contract.

Based upon the findings made by the Commission above regarding the analysis provided in support of the issuance of the CPCN in accordance with the Settlement Agreement and as required by Ind. Code § 8-1-8.4-7(b)(1), we find that the public convenience and necessity will be served by the construction, implementation and use of the Rockport CCT Project when the total capital cost as defined in Section A.3 of the Settlement Agreement is considered.

7. **Cost Recovery.** If we approve a compliance project and the associated federally mandated costs, Ind. Code § 8-1-8.4-7(c) sets forth the ratemaking that applies. This ratemaking has been referred to as an 80/20 cost recovery.[1] The Settlement Agreement sets forth how the accounting ratemaking and the new Federal Mandate Rider will be implemented. The Settlement Agreement also expressly incorporates the 25% cap on I&M's projected federally mandated costs set forth in Ind. Code § 8-1-8.4-7(c)(3). Should I&M's actual costs exceed the 25% cap, the statute requires I&M to provide specific justification for and seek recovery of those additional costs in its next general rate case. These provisions were supported by the testimony in support of the Settlement Agreement offered by I&M and the OUCC. We find the accounting and ratemaking provisions of the Settlement Agreement to be reasonable and consistent with Ind. Code § 8-1-8.4-7. We further find these provisions should be approved and the Federal Mandate Rider proceedings should be docketed as Cause No. 44331 ECR X.

C. **Settlement Agreement.** Based upon the findings above, we find that the Settlement Agreement is reasonable and consistent with the governing regulatory framework. The Rockport CCT Project is a cost-effective means of maintaining the availability of the Rockport Units that complies with environmental regulations, allows the plant to continue to serve customer needs, and does so in a manner that mitigates the rate impact on customers. We find the Rockport CCT Project is the best option to permit Rockport to continue to provide generation needed to serve I&M's customers' needs. We further find and conclude that the

[1] Ind. Code § 8-1-8.4-7(c) allows for recovery of 80% of the approved costs, including up to 80% of the capital cost identified in Paragraph 9.B.6 above, via a periodic rate adjustment mechanism and for deferral treatment of the remaining 20% of the approved costs. Any amounts above the approved costs would be addressed in a future base rate case.

Settlement Agreement terms regarding accounting, depreciation, and ratemaking provide a reasonable and cost effective means of addressing and resolving the OUCC and Industrial Group concerns while recognizing I&M's operational needs. Therefore, we conclude that the Settlement Agreement is reasonable and in the public interest and should be and is approved.

The parties agree that the Settlement Agreement should not be used as precedent in any other proceeding or for any other purpose, except to the extent necessary to implement or enforce its terms. Consequently, with regard to future citation of the Settlement Agreement, we find that our approval herein should be construed in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434, 1997 Ind. PUC LEXIS 459, at *19-22 (IURC March 19, 1997).

D. **Confidentiality Findings.** I&M filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information on July 15, 2013, which Motion was supported by affidavit showing documents to be submitted to the Commission were trade secret information within the scope of Ind. Code §§ 5-14-3-4(a)(4) and (9) and Ind. Code § 24-2-3-2. The Presiding Officers issued a Docket Entry on July 19, 2013 finding such information to be preliminarily confidential, after which such information was submitted under seal. There was no disagreement among the Parties as to the confidential and proprietary nature of the information submitted under seal in this proceeding. We find all such information is confidential pursuant to Ind. Code §§ 5-14-3-4 and 24-2-3-2, is exempt from public access and disclosure by Indiana law and shall be held confidential and protected from public access and disclosure by the Commission.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. The Settlement Agreement is approved in its entirety.

2. I&M's Rockport CCT Project is approved, including the construction and use of emission reduction technologies.

3. I&M is issued a Certificate of Public Convenience and Necessity under Ind. Code § 8-1-8.4-7(b) for the Rockport CCT Project. This Order constitutes the Certificate.

4. The projected federally mandated costs set forth in the Settlement Agreement for the Rockport CCT Project are approved.

5. The Rockport CCT Project costs are federally mandated costs and cost recovery shall be implemented in accordance with Ind. Code ch. 8-1-8.4 as provided in the Settlement Agreement.

6. I&M is authorized to add to the value of I&M's property for ratemaking purposes the value of the Rockport CCT Project in accordance with the Commission's CWIP ratemaking rules and the Settlement Agreement. Pursuant to 170 I.A.C. 4-6-21 and as provided in the Settlement Agreement, I&M shall add the approved return to its net operating income authorized by the Commission for purposes of Ind. Code § 8-1-2-42(d)(3) in all subsequent fuel adjustment charge proceedings.

7. I&M is authorized to depreciate the Rockport CCT Project utilizing a 10-year life, except for the Preconstruction Costs which shall be amortized over the remaining life of the Rockport facility as provided in the Settlement Agreement.

8. The proposed Federal Mandate Rider is approved and rider filings shall be docketed as Cause No. 44331 ECR X.

9. Eighty percent (80%) of the approved federally mandated costs shall be recovered by I&M through the Federal Mandate Rider in accordance with Ind. Code § 8-1-8.4-7(c) and the Settlement Agreement.

10. I&M is authorized to defer and record as a regulatory asset post-in-service depreciation and O&M expense associated with the Rockport CCT Project, with any resulting variances reconciled in subsequent Federal Mandate Rider filings as provided in the Settlement Agreement.

11. As provided in the Settlement Agreement, I&M is authorized to accrue and recover AFUDC on the cost of the Rockport CCT Project, and the accrual of AFUDC shall continue on any unrecovered value of the Rockport CCT Project until ratemaking treatment for the value of the property is effective, including post-in-service AFUDC, on costs not yet recognized in the Federal Mandate Rider from the in-service date until ratemaking treatment reflecting the value of that Property is effective.

12. I&M is authorized to defer and record as a regulatory asset twenty percent (20%) of the federally mandated costs in accordance with Ind. Code § 8-1-8.4-7(c) and the Settlement Agreement.

13. The information filed in this Cause pursuant to motion for protective order is deemed confidential pursuant to Ind. Code §§ 5-14-3-4 and 24-2-3-2, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

14. This Order shall be effective on and after the date of its approval.

ATTERHOLT, BENNETT, LANDIS AND ZIEGNER CONCUR; MAYS ABSENT:

APPROVED: NOV 13 2013

I hereby certify that the above is a true and correct copy of the Order as approved.

Brenda A. Howe

Brenda A. Howe
Secretary to the Commission

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANA MICHIGAN POWER COMPANY ("I&M"), AN INDIANA CORPORATION, FOR APPROVAL OF CLEAN COAL AND ENERGY PROJECTS AND QUALIFIED POLLUTION CONTROL PROPERTY AND FOR ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR USE OF CLEAN COAL TECHNOLOGY ("PROJECTS"); FOR ONGOING REVIEW; FOR APPROVAL OF THE TIMELY RECOVERY OF COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF SUCH PROJECTS THROUGH I&M'S CLEAN COAL TECHNOLOGY RIDER; FOR APPROVAL OF DEPRECIATION PROPOSAL FOR SUCH PROJECTS; FOR AUTHORITY TO DEFER COSTS INCURRED DURING CONSTRUCTION AND OPERATION, INCLUDING CARRYING COSTS, DEPRECIATION, AND OPERATION AND MAINTENANCE COSTS, UNTIL SUCH COSTS ARE REFLECTED IN THE CLEAN COAL TECHNOLOGY RIDER, FOR APPROVAL OF COST RECOVERY OF COSTS INCURRED FOR ROCKPORT ENVIRONMENTAL PROJECT, , ALL PURSUANT TO IND. CODE §§ 8-1-2-6.1, 8-1-2-6.7, 8-1-2-6.8, 8-1-2-42(a), 8-1-8.4-6, 8-1-8.4-7, 8-1-8.7, 8-1-8.8, AND 170 IAC 4-6-1 ET SEQ.	)	CAUSE NO. 44331

STIPULATION AND SETTLEMENT AGREEMENT

Indiana Michigan Power Company ("I&M" or "Company"), Intervenor Industrial Group ("Industrials"), and the Indiana Office of Utility Consumer Counselor ("OUCC"), (collectively the "Parties" and individually "Party") solely for purposes of compromise and settlement and having been duly advised by their respective staff, experts and counsel, stipulate and agree that the terms and conditions set forth below represent a fair, just and reasonable resolution of all matters pending before the Commission in this Cause, subject to their incorporation by the Indiana Utility Regulatory Commission ("Commission") into a final, non-appealable order ("Final Order") without modification or further condition that may be unacceptable to any Party. If the Commission does not approve this Stipulation and Settlement Agreement ("Settlement Agreement"), in its entirety, the entire Settlement Agreement shall be null and void and deemed withdrawn, unless otherwise agreed to in writing by the Parties.

A. TERMS AND CONDITIONS

The Settling Parties stipulate and agree as follows:

1) I&M's Rockport CCT Project will be approved, including the construction and use of emission reduction technologies and associated facilities.

2) I&M is issued a Certificate of Public Convenience and Necessity for the Rockport CCT Project.

3) The total estimated capital cost (excluding Allowance for Funds Used During Construction (AFUDC)) provided by I&M in this Cause for the Rockport CCT Project in the amount of $258,052,000 set forth on Petitioner's Exhibit SMK-1 (Updated) attached hereto is reasonable and will be approved consistent with the clarification set forth below:

   a) As shown on Petitioner's Exhibit SMK-1 (Updated), the total estimated capital cost of the Rockport CCT Project (($258,052,000 excluding AFUDC) is allocated to I&M through two components as follows:

      i. "I&M's Direct Ownership Share"; and

      ii. "I&M's Allocated Share" of the total estimated capital costs allocated to I&M via I&M's purchases from AEP Generating Company.

   As shown on Petitioner's Exhibit SMK-1 (Updated), Kentucky Power is also allocated a share of the total estimated capital costs of the Rockport CCT Project (the "Kentucky Costs"). This proceeding and this Settlement Agreement do not involve the Kentucky Costs.

   b) The total estimated capital cost of the Rockport CCT Project includes the "Preconstruction Costs" incurred in pursuing the installation of a dry flue gas desulfurization system on one unit at the Rockport Plant (Cause No. 44033).

   c) As shown on Petitioner's Exhibit SMK-1 (Updated), I&M's Direct Ownership Share of the total estimated capital costs ($258,052,000 excluding AFUDC) is estimated to be $129,026,000 (Total Company). I&M's Direct Ownership Share includes an estimated $22,013,000 in Preconstruction Costs.

d) As shown on Petitioner's Exhibit SMK-1 (Updated), I&M's Allocated Share of the total estimated capital costs of the Rockport CCT Project is estimated to be $90,318,000 (Total Company).

e) While the total estimated capital cost of the Rockport CCT Project is reasonable and should be approved, only the Indiana Retail Jurisdictional Share of I&M's Direct Ownership Share (including Preconstruction Costs) will be recovered under Ind. Code §8-1-8.4 (the Federal Mandated Requirements Statute) as provided below.

f) I&M's Allocated Share of the Rockport CCT Project will be recovered in subsequent I&M general rate case(s). To the extent I&M's Allocated Share is no more than the estimated costs described herein, then the prudence of such expenditures shall not be subject to challenge other than as contemplated by paragraph 6(j) below.

g) The Indiana Retail Jurisdictional Share of I&M's Direct Ownership Share (including the Preconstruction Costs) will be determined using the jurisdictional demand allocation factor approved by the Commission in I&M's general rate cases. By way of illustration, as shown on Petitioner's Exhibit SMK-1 (Updated), the jurisdictional demand allocation factor approved in I&M's most recent general rate case (Cause No. 44075) is 64.65519%. Applied to I&M's Direct Ownership Share (Total Company), the resulting capital cost using the current jurisdictional demand allocation factor is $83,422,005. The Indiana Retail Jurisdictional allocation factors may be reviewed and updated in I&M's subsequent general rate cases.

h) Also by way of illustration, using the current allocation factor, the Indiana Retail Jurisdictional Share of the Preconstruction Costs reflected in I&M's Direct Ownership Share is estimated to be $14,232,547 ($44,026,000 * 50% * 64.65519%). Without waiver of the Parties' position regarding the eligibility of said Preconstruction Costs for cost recovery and solely for purposes of compromise, the Parties agree that the Indiana Retail Jurisdictional Share of the Preconstruction Costs will be amortized and recovered under Ind. Code §8-1-8.4 over the remaining life of the Rockport facility and that the Preconstruction Costs, along with the remaining Indiana Retail Jurisdictional Share of I&M's Direct Ownership Share will earn a return based on I&M's weighted average cost of capital as provided below.

4) The Rockport CCT Project may have incremental O&M costs (including consumables), depreciation, and tax expense over and above the amount embedded in I&M's base rates. Such costs will be recovered under Ind. Code §8-1-8.4 as provided for in this Settlement Agreement if reasonable and necessary.

5) I&M's Rockport CCT Project constitutes Clean Coal Technology, a Clean Energy Project and Qualified Pollution Control Property and is eligible for the ratemaking treatment described in Ind. Code §§8-1-8.7, 8-1-8.8, 8-1-2-6.7 and 8-1-2-6.8. The cost of the Rockport CCT Project, including capital, operating and maintenance (including

consumables), depreciation, tax and financing costs are also Federally Mandated Costs under Ind. Code §8-1-8.4-4.

6) Without waiver of I&M's position regarding the eligibility of the Rockport CCT Project for cost recovery under Ind. Code §§8-1-8.7, 8-1-8.8, 8-1-2-6.7 and 8-1-2-6.8, and solely for purposes of compromise, the cost recovery for the Indiana Retail Jurisdictional Share of I&M's Direct Ownership Share (including Preconstruction Costs) and associated operating and maintenance (including consumables), depreciation, tax and financing costs (referred to below as the Federally Mandated Costs) will be implemented under Ind. Code §8-1-8.4 as set forth below.

   a) Eighty percent (80%) of the Federally Mandated Costs shall be recovered in a timely manner through a Federal Mandate Rider including: a carrying charge at the overall weighted average cost of capital (weighted average rate of return) on capital costs/expenditures and Preconstruction Costs during construction and after a project is placed in service; operating and maintenance (including consumables), depreciation, tax, financing costs and post in service AFUDC on capital costs and Preconstruction Costs. The Federal Mandate Rider will be established in this docket. I&M may file its first Federal Mandate Rider proceeding within three (3) months of a final Commission Order approving this Settlement Agreement. I&M will request updates to its Federal Mandate Rider in six month intervals with the factors established under the Rider remaining in place until superseded by updated factors. I&M will be authorized to defer and record as a regulatory asset post in-service depreciation, incremental operations and maintenance expense (including consumables), tax and post in service AFUDC on capital costs until the Commission approves ratemaking treatment through the Federal Mandate Rider with any resulting variances reconciled in subsequent Rider filings.

   b) Twenty percent (20%) of the Federally Mandated Costs, including: AFUDC on capital costs during construction and Preconstruction Cost, post in service AFUDC on capital costs and Preconstruction Costs; after project is placed in service, and operating and maintenance (including consumables), depreciation, and taxes will be deferred until rates are established in subsequent I&M general rate case(s).

   c) While approved as a Federally Mandated Project under Ind. Code §8-1-8.4, the 80% recovery through the Federal Mandate Rider will be set up to use the same structure currently in place for timely recovery of costs and expenses through I&M's Clean Coal Technology Rider (CCTR).

   d) Timely cost recovery of the Rockport CCT Project Federally Mandated capital costs provided for herein will be subject to subsection (j) below.

   e) I&M will be authorized to add to the value of I&M's property for ratemaking purposes the value of the Indiana Retail Jurisdictional Share of I&M's Direct Ownership Share of the total Rockport CCT Project capital costs (including Preconstruction Costs) in accordance with the Commission's construction work in progress ratemaking rules. Pursuant to 170 IAC 4-6-21, I&M shall add the approved return to its net operating income authorized by the Commission for purposes of Ind. Code §8-1-2-42(d)(3) in all subsequent fuel adjustment charge proceedings, pro-rated for the effective period of the approved rates.

f) I&M will be authorized to accrue and recover AFUDC on the capital cost of the Rockport CCT Project, and the accrual of AFUDC shall continue on any unrecovered value of a particular Project until ratemaking treatment for the value of the property is effective, including post-in-service AFUDC on costs not yet recognized in the Federal Mandate Rider for the period following the in-service date of a particular project until ratemaking treatment reflecting the value of that property is effective.

g) The 80% recovery through the Federal Mandate Rider will be established as a new case number, such as Cause No. 44331 ECR-X.

h) The 20% cost recovery allowed under the Federally Mandated Requirements Statute will be deferred with all attributable costs allowed under §8-1-8.4 for recovery in I&M next applicable general base rate case(s).

i) In the event the actual construction costs (excluding AFUDC) exceed the Federally Mandated costs of the Rockport CCT Project by more than twenty-five percent (25%), then the Indiana Retail Jurisdictional Share of I&M's Direct Ownership Share of the Rockport CCT Project costs above the 25% will be presented by I&M with specific justification and considered for rate recovery by the Commission in I&M's next applicable general base rate case(s).

j) Except as provided above for Preconstruction Costs, I&M will be authorized to depreciate the Indiana Retail Jurisdictional Share of I&M's Direct Ownership Share of the Rockport CCT Project utilizing a 10 year life. Notwithstanding the foregoing provision, in the event the Rockport Unit 2 lease is not renewed beyond the end of its current term in 2022 and I&M is no longer using the asset, then no later than six (6) months prior to the expiration of the lease, I&M will file a petition with the Commission for approval of the Company's proposal regarding any accounting and ratemaking issues associated with wrapping up the Rockport CCT Project costs and attributes attached to Unit 2 and the ongoing nature of the prospective cost recovery. This provision is without waiver of each Party's respective rights to make arguments in such subsequent proceeding regarding the recoverability, accounting and ratemaking for such Unit 2 costs, including the right to propose or oppose the recovery of such costs through the Federal Mandate Rider be continued on a subject to refund basis pending the outcome of such proceeding.

7) The allocation of costs in the Federal Mandate Rider will be based on the allocation methods approved by the Commission in I&M's base rate case (Cause No. 44075), which includes the 6 coincident peak (CP) method for determining the demand allocation.

8) The information filed in this Cause pursuant to motion for protective order is deemed confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2, is exempt from

public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

9) Any settlement agreement will be formalized using standard form of settlement and associated boilerplate consistent with past agreements between I&M, the OUCC and Industrial Group.

10) The Settling Parties will file a Motion for Leave to File Settlement Agreement and request the Commission to conduct a settlement hearing on August 8, 2013. The Settling Parties will file testimony in support of the Settlement Agreement at least five (5) business days prior to the settlement hearing.

B. PRESENTATION OF THE SETTLEMENT TO THE COMMISSION

1. The Parties shall support this Settlement Agreement before the Commission and request that the Commission expeditiously accept and approve the Settlement Agreement. The concurrence of the Parties with the terms of this Settlement Agreement is expressly predicated upon the Commission's approval of the Settlement Agreement in its entirety without any modification or any condition that may be unacceptable by any Party. If the Commission does not approve the Settlement Agreement in its entirety and without change, the Settlement Agreement shall be null and void and deemed withdrawn, upon notice in writing by any Settling Party within fifteen (15) business days after the date of the Final Order that any modifications made by the Commission are unacceptable to it.

2. The Parties shall jointly move for leave to file this Settlement Agreement and supporting evidence. Such evidence together with the evidence previously prefiled by the Parties in this Cause will be offered into evidence without objection and the Parties hereby waive cross-examination. The Parties propose to submit this Settlement Agreement and evidence conditionally, and that, if the Commission fails to approve this Settlement Agreement in its entirety without any change or with condition(s) unacceptable to any Party, the Settlement and supporting evidence shall be withdrawn and the Commission will continue to hear Cause No.

44331 with the proceedings resuming at the point they were suspended by the filing of this Settlement Agreement.

3. A Final Order approving this Settlement Agreement shall be effective immediately, and the agreements contained herein shall be unconditional, effective and binding on all Parties as an Order of the Commission.

4. The Parties shall jointly agree on the form, wording and timing of public/media announcement (if any) of this Settlement Agreement and the terms thereof. No Party will release any information to the public or media prior to the aforementioned announcement. The Parties may respond individually without prior approval of the other Parties to questions from the public or media, provided that such responses are consistent with such announcement and do not disparage any of the Parties. Nothing in this Settlement Agreement shall limit or restrict the Commission's ability to publicly comment regarding this Settlement Agreement or any Order affecting this Settlement Agreement.

C. EFFECT AND USE OF SETTLEMENT

1. It is understood that this Settlement Agreement is reflective of a negotiated settlement and neither the making of this Settlement Agreement nor any of its provisions shall constitute an admission by any Party to this Settlement Agreement in this or any other litigation or proceeding. It is also understood that each and every term of this Settlement Agreement is in consideration and support of each and every other term.

2. This Settlement Agreement shall not constitute and shall not be used as precedent by any person in any other proceeding or for any other purpose, except to the extent necessary to implement or enforce the terms of this Settlement Agreement.

3. This Settlement Agreement is solely the result of compromise in the settlement process and except as provided herein, is without prejudice to and shall not constitute a waiver of any position that any of the Parties may take with respect to any or all of the items resolved here and in any future regulatory or other proceedings.

4. The Parties agree that the evidence in support of this Settlement Agreement constitutes substantial evidence sufficient to support this Settlement Agreement and provides an adequate evidentiary basis upon which the Commission can make any findings of fact and conclusions of law necessary for the approval of this Settlement Agreement, as filed. The Parties shall prepare and file an agreed proposed order with the Commission as soon as reasonably possible.

5. The communications and discussions during the negotiations and conferences and any materials produced and exchanged concerning this Settlement Agreement all relate to offers of settlement and shall be privileged and confidential, without prejudice to the position of any Party, and are not to be used in any manner in connection with any other proceeding or otherwise.

6. The undersigned Parties have represented and agreed that they are fully authorized to execute the Settlement Agreement on behalf of their designated clients, and their successors and assigns, who will be bound thereby.

7. The Parties shall not appeal or seek rehearing, reconsideration or a stay of the Final Order approving this Settlement Agreement in its entirety and without change or condition(s) unacceptable to any Party (or related orders to the extent such orders are specifically implementing the provisions of this Settlement Agreement). The Parties shall support or not oppose this Settlement Agreement in the event of any appeal or a request for a stay by a person not a party to this Settlement Agreement or if this Settlement Agreement is the subject matter of any other state or federal proceeding.

8. The provisions of this Settlement Agreement shall be enforceable by any Party before the Commission and thereafter in any state court of competent jurisdiction as necessary.

9. This Settlement Agreement may be executed in two (2) or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

ACCEPTED and AGREED as of the 24 th day of July, 2013.

INDIANA MICHIGAN POWER COMPANY

Name: Marc E. Lewis
Its: Vice President

INDUSTRIALS

Name: Timothy L. Stewart
Its: Attorney

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

RC Helmen

Name: Randall C. Helmen
Its: Chief Deputy Consumer Counselor

INDS01 1409602v1

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

FILED

July 26, 2017

INDIANA UTILITY

REGULATORY COMMISSION

PETITION OF INDIANA MICHIGAN POWER COMPANY, AN INDIANA CORPORATION, FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN RATE ADJUSTMENT; (2) APPROVAL OF: REVISED DEPRECIATION RATES; ACCOUNTING RELIEF; INCLUSION IN BASIC RATES AND CHARGES OF QUALIFIED POLLUTION CONTROL PROPERTY, CLEAN ENERGY PROJECTS AND COST OF BRINGING I&M'S SYSTEM TO ITS PRESENT STATE OF EFFICIENCY; RATE ADJUSTMENT MECHANISM PROPOSALS; COST DEFERRALS; MAJOR STORM DAMAGE RESTORATION RESERVE AND DISTRIBUTION VEGETATION MANAGEMENT PROGRAM RESERVE; AND AMORTIZATIONS; AND (3) FOR APPROVAL OF NEW SCHEDULES OF RATES, RULES AND REGULATIONS.	)	CAUSE NO. 44967-NONE

SUBMISSION OF DIRECT TESTIMONY OF
<u>RODERICK KNIGHT</u>

Petitioner, Indiana Michigan Power Company (I&M), by counsel, respectfully submits the direct testimony and attachments of Roderick Knight in this Cause.

Teresa Morton Nyhart (Atty. No. 14044-49)
Nicholas K. Kile (Atty. No. 15023-23)
Jeffrey M. Peabody (Atty No. 28000-53)
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Attorneys for Indiana Michigan Power Company

CERTIFICATE OF SERVICE

The undersigned certifies that the foregoing was served upon the following via electronic email, hand delivery or First Class, or United States Mail, postage prepaid this 26th day of July, 2017 to:

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Attorneys for INDIANA MICHIGAN POWER COMPANY

EXHIBIT I&M-_____

INDIANA MICHIGAN POWER COMPANY

PREFILED VERIFIED DIRECT TESTIMONY

OF

RODERICK KNIGHT

**PRE-FILED VERIFIED DIRECT TESTIMONY OF RODERICK KNIGHT
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY**

Q. What is your name and business address?

A. My name is Roderick Knight and my business address is Knight Cost Engineering Services, LLC (Knight CES), 22 Mountain View Terrace, New Milford, Connecticut 06776.

Q. What is your position?

A. My position is President of Knight Cost Engineering Services, LLC (KCES).

Q. What is KCES?

A. KCES is a sole proprietor cost engineering company under which I provide cost engineering services, primarily to the nuclear industry.

Q. What are your responsibilities within that organization?

A. As the sole proprietor of the company, I am responsible for all aspects of cost engineering including estimating, planning, scheduling, material takeoff, cash flow analysis and litigation support. I also contract support staff on an as-needed basis and oversee their work.

Q. What is your educational and professional experience?

A. I earned a Bachelor of Science degree in Civil Engineering from the University of New Haven in 1992, graduating Magna Cum Laude. I also earned a Bachelor of Science degree in Natural Resource Management from the University of Maine in 1981. I am a member of Chi Epsilon, an honorary Civil Engineering Society and a Certified Cost Professional through AACE International.

I have over 30 years of experience performing cost estimates for the nuclear industry for commercial, government and research facilities. My expertise includes the analysis of post shutdown cost reduction methods including the analysis of spent fuel storage options, volume reduction techniques, staff levels and schedule optimization. I have also performed numerous prudency reviews of cost estimates developed by others, for confidential clients. More recently, I have taught classes on how to develop decommissioning cost estimates for the International Atomic Energy Agency (IAEA) to members from various countries. The IAEA work also includes the development of lesson plans for future workshops. I have also taught a similar class in South Korea.

I was formerly employed by SCIENTECH, Inc. and by its predecessor NES, Inc. from 1992 until 2004, when I started KCES. As an employee of SCIENTECH/NES I served as Project Manager in the preparation of well over 100 decommissioning cost estimates. I also served as one of eleven members on the EM-6 Expert Review Team for the Department of Energy at Brookhaven National Laboratory. I presented a paper entitled “How Utilities Can Achieve More Accurate Decommissioning Cost Estimates,” at the 1999 ANS Winter Meeting in Long Beach California. I also developed lesson plans and was an instructor at the SCIENTECH-sponsored Decommissioning Workshop. Prior to this, I was employed by TLG Engineering for seven years, where I was responsible for the management of decommissioning cost estimates from preliminary client contact to preparation of the final report.

I also have extensive international experience including numerous missions with the IAEA. These missions include providing decommissioning cost estimating support in Kazakstan for the BN-350 Nuclear Power Plant and in Croatia and Slovenia in support of the Krsko Nuclear Power Plant decommissioning plan. I have also worked as part of a SCIENTECH team contracted by PA Government Services (PA) to assist in developing and promoting a series of reforms for the Armenian energy sector.

In addition to developing decommissioning cost estimates for commercial nuclear power plants, I have developed estimates for a variety of facilities. These estimates were developed for a number of reasons, including proposal support, owner estimates and project funding. This work includes the development of estimates at several National Laboratories, including Los Alamos, Argonne and Brookhaven. In addition, I have developed estimates for manufacturing facilities and research facilities. Most of these estimates included the remediation of both radiological and hazardous wastes.

Q. What is the purpose of your testimony?

A. I was asked by Indiana Michigan Power Company (I&M or Company) to review and update the 2013 D.C. Cook Decommissioning Cost Study (2013 Study) to 2015 costs and conditions. The 2013 Study was also developed by KCES utilizing my proprietary estimating program. An updated study was required to determine whether the Company is adequately providing for the eventual decommissioning of the Donald C. Cook Nuclear Power Plant (Cook Plant). One decommissioning scenario was developed for the two-unit Cook Plant. This scenario includes the cost for the immediate decommissioning of the site (DECON), on-site spent fuel storage of spent fuel and the removal of clean structures. The cost estimate is contained in the document entitled Decommissioning Study of the D.C. Cook Nuclear Power Plant, January 21 2016, Revision 0, (2016 Study), as prepared for I&M by KCES, and which has been marked as Attachment RK-1. The purpose of my testimony is to present the results of this study.

Q. Are you sponsoring any attachments in this proceeding?

A. Yes. I sponsor the following attachments which were prepared or assembled by me or under my supervision:

- Attachment RK-1: Decommissioning Study of the D.C. Cook Nuclear Power Plant, January 21 2016, Revision 0, (2016 Study)
- Attachment RK-2: Comparison of the 2012 and 2015 D. C. Cook Decommissioning Estimates, Rev 2

Q. WHAT IS INCLUDED IN THE 2016 STUDY?

A. The report contains a description of the decommissioning scenario considered to be feasible for the Cook Plant, the cost estimate, and the estimate of the schedule of performance. All costs are in July 2015 dollars, which means that although a task may not actually occur until after final shutdown, its cost is estimated as if it occurred in 2015. The decommissioning cost estimate is shown in Table 1 which follows:

Table 1
Summary of the 2015 Decommissioning Cost Estimate
For D.C. Cook Nuclear Power Plant

Decommissioning Scenario	Fuel Storage & Decommissioning Costs $	Dormancy Period Cost $	Delayed Dismantling Cost $	Total Program Cost $
DECON, Indefinite On-Site Dry Storage and Modified Spent Fuel Pool Systems				
Decommissioning	909,101,900	N/A	N/A	909,101,900
Fuel Storage	529,465,600	N/A	N/A	529,465,600
Greenfield	195,470,900	N/A	N/A	195,470,900
			TOTAL	1,634,038,400
Annual ISFSI Storage	4,912,700			4,912,700
ISFSI Decommissioning	56,952,300			56,952,300

Q. What is the decommissioning scenario?

A. The decommissioning scenario considered in the study is DECON. This acronym reflects the definition established by the NRC. This option is based on sequential shutdown of Cook Plant Units l and 2 with Unit 1 shutdown occurring on October 25, 2034, and Unit 2 on December 23, 2037.

Q. What are the line item entries “Decommissioning” and “Greenfield” on Table 1?

A. The Table 1 term Decommissioning refers to 10 Code of Federal Regulations (CFR) 50.75(c) costs pertaining to the achievement of decommissioning objectives and work but which specifically excludes the costs of removal and disposal of spent fuel and the removal of clean structures. The Table 1 term Greenfield refers to the costs of removal of clean structures and returning the site to greenfield conditions.

Q. What is the line item entry “Fuel Storage” in Table 1?

A. While the site is licensed under 10 CFR 50, 10 CFR 50.54(bb) requires funding by the licensee “for the management of all irradiated fuel at the reactor upon expiration of the reactor operating license until title to the irradiated fuel and possession of the fuel is transferred to the Secretary of Energy for its ultimate disposal in a repository.” The costs labeled Fuel Storage represent the costs that will be incurred after final shutdown of both Cook Plant units during the period of on-site spent fuel storage in the existing fuel storage pool, on-site dry storage in an Independent Spent Fuel Storage Installation (ISFSI), off-site dry storage at a private fuel storage facility, or some combination of the three. These are the costs that the utility will incur due to the post-shutdown management of spent fuel prior to acceptance by the Department of Energy for disposal at a repository. As prescribed in 10 CFR 50.75(c) a licensee must provide reasonable assurance that funds will be available for the decommissioning process. The NRC definition of decommissioning does not include the operation of the spent fuel pool or the construction and/or operation of an ISFSI. These costs may be included in a site specific estimate but should be clearly defined.

Q. Are these spent fuel-related costs included in the 2016 Study?

A. Yes, they are included and specifically identified as such. The 2016 Study updated not only the cost factors associated with spent fuel storage but also the assumptions used to determine the costs and schedules.

Q. Why was only one scenario considered?

A. As discussed the 2016 Study consists of one decommissioning scenario. The decommissioning alternative analyzed in this study is DECON. This alternative is further defined and described later in my testimony. The DECON scenario considers that spent fuel will be transferred to an on-site ISFSI within 7.5 years of Unit 2 shutdown. For this scenario it is assumed that the spent fuel will remain in an on-site ISFSI indefinitely.

The 2013 Study provided costs for five scenarios. The reduction to one scenario in the 2016 Study from the five scenarios in the 2013 Study is based on several factors. There has been little movement toward the development of an off-site spent fuel storage repository since 2013. The Annual Capacity Report, identifying spent fuel shipping rates and allocation, has not been updated. There is no viable alternative to the on-site storage of spent fuel. For planning purposes, it is prudent to assume a long term post-shutdown storage of spent fuel will be required. As I&M has historically updated this study every 3 years, new developments in spent fuel storage can be addressed as they occur.

The DECON scenario is typically the preferred scenario when the funds are available to proceed with decommissioning immediately after cessation of operations. It is anticipated that I&M will have a fully funded decommissioning fund at the time of Unit 2 shutdown allowing for immediate decommissioning. Having all spent fuel transferred to dry storage will simplify decommissioning as well as reduce annual spent fuel storage costs.

Q. How was the 2016 Study developed?

A. The 2016 Study, consistent with prior studies, is site specific. Unit cost factors for the various elements of work comprising the decommissioning programs were applied to each element of plant equipment and structures. These cost factors reflect 2015 labor rates experienced at Cook Plant. The cost estimate was derived by the "building block" approach, whereby the process of decommissioning was broken down into small elements of work and each element of work activity was individually estimated. These activities were laid out in an optimum chronological sequence and schedule, and the additional costs of management and support services, such as health physics, were estimated for the defined work period. The total estimated costs calculated in the study are the sum of these many basic work elements. The costs directly associated with decommissioning and the costs associated with spent fuel storage are presented in separate tables in the study.

Q. Please further describe the scenario that you considered in the 2016 Study.

A. The DECON option is defined as the removal from the plant site of fuel assemblies, source material, radioactive fission and corrosion products, and all other radioactive and contaminated materials having activities above license limits. The reactor pressure vessel and internals will be removed using remote tooling and handling methods. Conventional removal and demolition techniques will be applied to the remaining systems and structures with contamination controls employed as required. After removal of all fixed and removable contamination the site may be released for unrestricted use with no further licensing requirements. The remaining buildings, non-radioactive structures and systems may also be removed and disposed of as is considered in the study. This program would result in a site that could be used for any purpose, since the entire nuclear power plant facility would be dismantled and removed from the site.

Q. What is the benefit of DECON with respect to social and economic impacts?

A. The DECON scenario allows for a quick termination of the license and a return to unrestricted use of the site, eliminating long-term maintenance and surveillance costs. There is also a knowledgeable workforce available to assist in the decommissioning. The DECON alternative also eliminates the uncertainty of the availability of low-level waste facilities in the future. The DECON scenario does come at a cost of higher worker and public doses due to lack of decay time. This increased exposure can be controlled through the use of engineered safety barriers and procedural controls as evidenced by the recent successful decommissioning projects.

Q. What caused the increase in spent fuel storage costs compared to the 2013 Study?

A. There is an increase in the spent fuel storage cost of $143.2 million. The major reason for this increase is due to the increase in the estimate to construct the expansion to the spent fuel storage pad. In the 2013 Study the estimate for the expanded pad was based on the actual cost to construct the existing pad. The 2013 Study estimate for the pad expansion was $25.1 million, before contingency, for 120 additional storage casks. The 2016 Study uses an estimate that was developed in 2015 by site personnel for the expansion of the pad. This estimate was $135 million, before contingency, for 111 additional storage casks. In both cases the expansion would be sufficient to hold all spent fuel on site after both units shutdown.

This increase was somewhat offset by the decrease in the cost of the spent fuel storage casks. While the cost of the casks increased, from $1.93 million each to $2 million each, fewer casks were estimated to be required. At the time the 2013 Study was being prepared it was estimated that 120 additional casks would be required after shutdown to empty the spent fuel pool. Based on a revised analysis of spent fuel discharges this number was reduced to 111 additional casks. Table 2 provides a summary of spent fuel storage costs.

Except for one modification, the Utility Staff personnel levels associated with the post-shutdown storage of spent fuel have remained the same as in the 2013 Study. The Utility Staff level during period 4 was increased from 14.25 to 33 in the 2016 Study. This increase is due to the in-pool spent fuel cooling period increasing from 5 years to 7 years. This increase causes spent fuel to remain in the spent fuel pool for the majority of period 4, requiring a larger staff.

There were a few changes to the Security Staff levels associated with spent fuel storage. These modifications are a result of new information provided by AEP. Period 4 was also modified due to the increase from 5 years to 7 years for in-pool cooling.

The DECON scenario in both the 2013 Study and the 2016 Study assumes that spent fuel will remain on site indefinitely. The annual costs for long storage increased approximately $432,646 or 9.66%. The main reason for this increase is due a change in the methodology used to calculate the O&M expenses during decommissioning. Since KCES received a more detailed list of these expenses, a more accurate assessment of the costs incurred during decommissioning was made. A more detailed description of the O&M costs is provided below. This increase was partially offset by a decrease in the Utility staff overhead rate from 69.73% to 29.84%. In addition, the spent fuel storage maintenance costs were included in the O&M budget and these values were used in the 2016 Study, as opposed to being estimated separately in the 2013 Study. Table 2 provides a summary of the dry spent fuel storage costs.

Table 2 – Spent Fuel Storage Costs
(Costs include contingency – see contingency discussion on page 15 below)

	2013 Totals	**2016 Totals**	**Cost Difference**
Undistributed Costs	$59,888,277	$78,678,208	$18,789,930
Pool sys, security & control room mods	$6,030,177	$6,105,135	$75,558
New pad construction cost	$30,861,277	$167,181,700	$136,320,423
Additional cask costs	$289,462,600	$277,500,000	-$11,962,600
Total	$386,242,332	$529,465,643	$143,223,311
Number of new casks	120	111	

Cost per cask, excluding contingency	$1,929,750	$2,000,000	$70,250
Period 7 Duration, months	12	12	
Annual Period 7 costs	$4,480,089	$4,912,735	$432,646

Q. What are the other major contributors to the cost differences?

A. The Decommissioning costs increased approximately $106.7 million or 13.30%. The Greenfield costs increased approximately $53.4 million or 37.54% from the DECON scenario in the 2013 Study to the 2016 Study. There are several areas that caused these increases.

Structures and component removal costs increased $40.9 million or 11.26% overall. The systems and structures inventory for the 2013 Study were developed in the 1990s and have been used in every estimate since then. Over the years the unit cost factors have been revised to better reflect industry experience. The systems and structures inventory were developed from current site drawings and database for the 2016 Study. This allowed for better alignment with the current unit cost factors.

Based on the new inventory there was some change in waste volumes. There is now a detailed material takeoff to support the 2016 Study. Based on the changes to the inventories clean demolition and clean disposal increased $35.2 million or 55.74% and $24.5 million or 81.53%, respectively. The decontamination of structures decreased $2.2 million or 4.04%, while the removal of contaminated systems decreased $10.5 million or 20.44%. The majority of these changes are due to the recalculation of the system and structures inventory. Structures and component removal costs are affected, to a much less extent, by the waste disposal and labor costs. Waste disposal costs decreased $6.6 million or 3.47% while labor rates increased 0.85% on average. The Comparison Report provided as Attachment RK-2 provides additional details. O & M Budget item costs increased by approximately $47.7 million or 214.24%. The basis for these costs is similar to that used in the 2013 Study in that the cost for each period was based on a percent of that incurred during operations. At the time of the 2013 Study, the percentages were applied to the operating costs at the department level. The basis was supplied by AEP for a 2006 Study, escalated for each subsequent update, and was not sufficiently detailed to allow for the percentages to be applied at a lower level. For the 2016 Study AEP supplied a more detailed version of these costs, 457 line items versus 190 in 2006. The new information allowed for the percentages to be applied on a line item basis. As an example, at the time of the 2013 Study the same percentage was applied to all costs in the business services department. For the 2016 Study, a separate percentage was applied to each cost category within the business services department. This added detail allows for a better tracking of the costs through the decommissioning.

Utility Staff costs increased by approximately $3.4 million or 2.56% from the 2013 Study to the 2016 Study. The total Utility Staff man-years increased from 889 to 1,066 due to a schedule change. The post shut-down schedule duration increased from 97 months to 112 months. There were two reasons for this increase. The first is due to a revision to the reactor vessel and reactor vessel internals removal duration. The duration increased from 11 months in the 2013 Study to 21 months in the 2016 Study. This increase was due to a modification in the calculations based on more current information. The second is that the in-pool spent fuel cooling period was increased from 5 years to 7 years. The result was that the period dependent costs increased more than the increase due to inflation.

Based on the information provided by AEP, the average base salary increased approximately 25%. Fringes and payroll tax decreased from 69.73% to 29.84%, a 57.21% decrease. This decrease is due to a revised method for determining the Utility overhead percentage rate. The combined effect is to decrease the average cost per man-year by 14.47%.

The Comparison Report provides additional details of the period dependent costs.

Q. How were waste disposal costs determined in the Cook Plant Study?

A. A matrix of currently operating low level waste disposal facilities and their current disposal costs was developed. The majority of Low Level Waste was assumed to qualify for processing as Bulk Survey For Release (BSFR), this includes the reactor building floors and walls that will be removed in bulk. The remaining Class A waste will be disposed of at either the Energy*Solutions* Clive, Utah facility, or at the Waste Control Specialist, LLC (WCS) facility in Andrews, Texas.

The WCS facility is currently licensed to accept Class B and C waste. This study assumes that all Class B & C waste will be disposed of at WCS. There is currently only a published fee and surcharge structure for in compact generators. Based on guidance from WCS personnel, increasing the published fees and surcharges by 20% would be representative of the rates that would be charged to out of compact generators. The base disposal rate for Class B & C waste is currently $2,680/cubic foot. This rate was provided by AEP.

Additionally, there is a dose rate surcharge and a millicurie charge that must be added. The basic millicurie charge is $0.55 per millicurie up to $220,000 per shipment. There is also a weight surcharge, up to $20,000 per shipment; a dose rate surcharge, up to $400 per cu. ft.; an irradiated hardware there is an additional surcharge of $75,000 per shipment and a cask handling surcharge of $2,500 per cask. Finally there are State and County fees of 5% each. These rates appear to be unchanged from the time of the 2013 Study. This estimate includes all applicable surcharges and fees.

Table 3 provides a comparison of the disposal rates and volumes between the 2013 Study and the 2016 Study. While the disposal costs either increased or stay the same, the overall costs decreased due to a larger volume going out as BSFR. Smelting was not included in the 2016 Study due to uncertainties in the industry.

Table 3 – Waste Summary

Waste Disposal (without contingency)	**2013**	**2016**	
Contaminated Disposal, Includes surcharges	$191,363,101	$184,723,286	-3.47%
Energy*Solutions* rate, $/cu ft	$158.54	$171.84	8.39%
Energy*Solutions* volume, cu. ft.	278,239	190,644	-31.48%
Smelting rate, $/lb	$2.10		
Smelting volume, cu. ft.	188,051	Not Used	
WCS disposal rate, $/cu ft	$208.79	$208.79	0.00%
WCS disposal volume, cu. ft.	70,018	3,946	-94.36%
BSFR rate, $/lb	$0.13	$0.25	92.31%
BSFR volume, cu. ft.	2,879,629	3,389,951	17.72%

The 2016 Study assumes that the reactor vessel and reactor internals will be removed and disposed of based on the same methodology as in the 2013 Study. This waste is assumed to be disposed of at either the Energy*Solutions* facility in Clive, Utah or the WCS facility in Andrews, Texas in the estimate used in the 2016 Study. The increase is due, in part to the increase in disposal costs for B and C waste. Class B waste was increased from $300.00 per cubic foot to $2,680.00 and Class C from $1,200.00 per cubic foot to $2,680.00. There was also a modification to the vessel removal labor costs based on recent experience, increasing the labor costs for the 2016 Study.

The Comparison Report provides details on variations in undistributed costs, starting on page two.

Q. What is the ISFSI decommissioning cost?

A. The 2013 Study identified an ISFSI decommissioning cost of $44,370,355 for scenario 1 (DECON). The 2016 Study identifies an ISFSI decommissioning cost of $56,952,300. The ISFSI decommissioning cost includes the cost to dispose of the concrete overpack and concrete pad as contaminated material. It was assumed that this bulk material would be eligible for processing as BSFR material. The cost increase is primarily due to the increase in the BSFR processing cost from $0.13 per pound to $0.25 per pound.

Q. What is the basis of the contingency factors included in the 2016 Study?

A. Contingencies are applied to cost estimates primarily to allow for unknown or unplanned occurrences during the decommissioning program, *e.g.* increased radioactive waste material volumes over that expected, equipment breakdowns, weather delays, labor strikes, etc. The U.S. Department of Energy (DOE) Cost Estimating Guide, DOE G 430.1-1, 3-28-97, defines contingency as follows:

> Covers costs that may result from incomplete design, unforeseen and unpredictable conditions, or uncertainties within the defined project scope. The amount of contingency will depend on the status of design, procurement, and construction, and the complexity and uncertainties of the component parts of the project. Contingency is not to be used to avoid making an accurate assessment of expected costs.

DOE G 430.1-1 provides a recommended range of contingencies as a function of program design:

Time of Estimate	Contingency Range as a % of Total Estimate
Planning Phase	20-30
Budget	15-25
Title I	10-20
Title II	5-15

Another source for published contingency values is the AIF/NESP-0036 "Guidelines for Producing Nuclear Plant Decommissioning Cost Estimates" (AIF). This document identifies contingencies for activities specific to nuclear power plant decommissioning, such as reactor internals removal. With the exception of system decontamination and reactor vessel and reactor internals removal and disposal, the contingencies presented in AIF are consistent with the values presented in DOE G 430.1-1 for a Budget/Title I estimate. The contingencies identified in AIF for system decontamination and reactor vessel and reactor internals removal and disposal are significantly higher than the ranges identified in DOE G 430.1-1. This is due to the lack of actual decommissioning work performed at the time AIF was published.

Knight CES has determined contingency values specific to Cook Plant utilizing the information presented in AIF and consistent with DOE G 430.1-1. A number of large scale decommissioning projects have recently been completed. The 2016 Study incorporates the lessons learned from these projects. As such, costs can be estimated with a greater degree of confidence than was true at the time AIF was published. This increased level of confidence allows for a downward adjustment to the recommended contingency, especially with regard to system decontamination and reactor vessel and reactor internals removal and disposal. The following table provides a summary of the contingency values used in the 2016 Study:

	Labor	Packaging	Transportation	Equip & Mat.	Disposal	Energy & Other, $
Engineering, Utility & DGC	15%					
Contam. components/concrete	25%		10%	15%	25%	
Reactor vessel & internals	50%		25%	25%	50%	
Clean components/concrete	15%		10%	25%	10%	
Supplies and consumables		25%				
Other						15%

Contingency rates identified above were applied to each cost category for each activity. The average overall contingency is 23.60% and 18.91% for Decommissioning and Greenfield, respectively.

The contingency analysis for on-site spent fuel storage varies slightly from that discussed above. There are two components comprising this contingency element: equipment capital cost contingency and on-site fuel storage operation contingency. The capital costs include the cost of acquisition of the multi-purpose fuel storage canisters and their on-site storage overpacks, the on-site dry storage facility, and the skid-mounted systems for modified wet storage in the spent fuel storage pool. Since these items are subject to many unknown or unplanned occurrences for which contingency is based, the above methodology will be applied. The operating costs of the spent fuel storage facility include only a 10% contingency because of the higher degree of knowledge and confidence in the factors comprising the operation of the wet or dry storage facility. It should be noted, however, that any variability as to the duration of the fuel storage period is excluded from the contingency. The average contingency for spent fuel storage is estimated at 23.06%. The calculated contingency for the ISFSI decommissioning is 29.04%, consistent with the final NRC rule I discuss below. A more detailed discussion of the development of the contingency factors is presented in Section 3.6 of the 2016 Study.

Q. Is there support to conclude that the Cook Plant can be completely dismantled?

A. Yes. In the United States in the past 15 or so years, twelve commercial nuclear power plants (NPP) have been successfully decommissioned. Each of these NPPs has had their license terminated or modified to allow for the on-site storage of spent fuel. In most of the NPP decommissionings, some combination of reactor vessel and reactor vessel internals have been removed, transported and disposed of in one piece. In some cases the shutdown was of an unplanned nature causing some lack of coordination in the first few years following shutdown. Once the intent to decommission was accepted, decommissioning proceeded in a timely and efficient manner. There are currently 16 NPPs in some phase of the decommissioning process.

In addition to the NPPs there have been numerous government-owned electric generation nuclear power plants, test reactors, research reactors, processing facilities, and many reactor facilities in Canada and Europe that have been successfully decommissioned using proven techniques. The lessons learned from the completed decommissioning projects have been well documented in the reports of successful program completions such as the *Maine Yankee Decommissioning Experience Report, Detailed Experiences 1997 – 2004*, EPRI, Palo Alto, CA: 2004 and the *Connecticut Yankee Decommissioning Experience Report, Detailed Experiences 1996 – 2006*, EPRI, Palo Alto, CA: 2006.

The basic activities of cutting piping, segmenting vessel internals, demolishing reinforced concrete and decontaminating contaminated systems and structures are independent of the size of the structure or megawatt rating of the plant. A contaminated 12-inch diameter pipe in a 3000 megawatt thermal plant utilizes the same segmentation process as a 12-inch diameter pipe in a 58 megawatt thermal plant, although the number of cuts will be greater in the larger plant. The major activities include removal of contaminated piping and components using conventional power saws or torches within contamination control envelopes, followed by disposal at a waste repository. Lessons learned from recently completed or ongoing decommissioning projects include the one piece removal of at least the reactor vessel, bulk removal of contaminated components versus decontaminate, survey and release and utility management of the project versus a decommissioning operations contractor. These recent decommissioning projects have learned from and built on the lessons learned from previous decommissioning programs. The successful application of these decommissioning techniques in both small and large nuclear power plants demonstrates assurance of decommissioning feasibility.

Q. Why are Greenfield costs included in the estimate?

A. While not required by NRC regulations, Greenfield or clean system and structure removal costs, have been calculated and are included in the 2016 Study. These costs may be required by local authorities to minimize liability. Removal of clean systems and structures may also be required to access contaminated components and structures. Recently completed decommissioning projects have included the removal of clean systems and structures, to some depth below grade, usually three feet.

Q. Was there any salvage or scrap value considered for any or the components?

A. It was assumed that there would be no salvage for any equipment left at the site at shutdown. Scrap value was not included in the estimate due to large fluctuations in scrap values. The 2016 Study assumes all clean material will be disposed of at a local landfill. This approach will also reduce liability concerns. The appropriateness of utilizing a scrap dealer can be addressed in future updates closer to shutdown.

Q. What regulatory requirements have the greatest effect on decommissioning?

A. CFR 50.82, Termination of License, governs the procedure to terminate the Part 50 license. Key provisions of the regulations include the certification of permanent cessation of operation within 30 days of permanent cessation, certification of permanent fuel removal, submittal of a Post-Shutdown Decommissioning Activity Report (PSDAR) within two years of shutdown and submittal of a License Termination Plan two years prior to license termination. The PSDAR must contain a site-specific decommissioning cost estimate. Regulatory Guide 1.184 provides a summary and timeline of these regulations.

On June 17, 2011, the NRC published a final rule amending its regulations to improve decommissioning planning. The rule became effective on December 17, 2012 and requires compliance by March 31, 2013. This rule will require licensees to report additional details in their decommissioning cost estimate. To assist in the implementation of the new rule, the NRC revised NUREG-1757, "Consolidated Decommissioning Guidance, Financial Assurance, Recordkeeping and Timeliness," specifically volume 3. Provisions of the final rule changes to 10 CFR 82 require that the site specific decommissioning cost estimate, included in the PSDAR, will now include the projected cost of managing spent fuel. An additional provision requires that after submitting the site specific decommissioning cost estimate and until the licensee has completed its final radiation survey permitting termination of the license, the licensee must submit, annually, a financial assurance status report.

Changes have also been made to 10 CFR 72 due to the final rule. The amended regulations require licensees to report additional details in their decommissioning cost estimates. In addition, at the time of license renewal and at intervals not to exceed 3 years the decommissioning funding plan must be updated and resubmitted.

Q. What factors have the greatest impact on the post-shutdown costs associated with on-site storage of spent fuel?

A. The two primary factors that will determine the magnitude of these costs are the date by which a spent fuel repository will be available and the rate at which DOE will be able to accept spent fuel at that repository. Both of these factors will directly influence the duration of the on-site storage period and, therefore, the costs associated with that period. The 2016 Study has assumed that spent fuel will remain on-site indefinitely, in dry storage. Since the DOE has not specified a spent fuel shipping start date or a shipping rate, it is prudent at this time to assume an indefinite spent fuel storage duration. Future studies will address developments as they occur.

Q. How will future developments in improved technology and increased or decreased costs be reflected in cost estimates for decommissioning?

A. The cost estimates prepared by Knight CES for I&M are based on current state-of-the-art technology and on current federal and state regulations. It is my understanding that I&M intends to review these estimates periodically and to revise them to account for cost increases or decreases as influenced by future technology, regulations, labor cost trends and waste disposal trends.

Q. Have you addressed the means by which decommissioning costs are to be financed or recovered?

A. No. I have addressed only the development of the total decommissioning cost estimate in 2015 dollars.

Q. Are there any changes that should be made to the January 2016 Study due to recent revisions to regulations or as the result of new information from ongoing or recently completed decommissioning projects?

A. The 2016 Study incorporates the most current information available to date. I believe that the costs developed for the 2016 Study provide a realistic estimate of the actual future costs and is reliable for I&M's financial planning purposes.

Q. Is it necessary to select a decommissioning method at this time?

A. No. The actual method or combination of methods selected to decommission the Cook Plant should be based on a detailed economic, engineering, and environmental evaluation of the alternatives considering the site and surroundings at the time of decommissioning and reflecting the latest experience in the decommissioning of similar nuclear power facilities. Considering that Cook Plant Units 1 and 2 are licensed to operate until 2034 and 2037, respectively, changes in waste disposal and/or processing costs, locations and methods are likely. NRC regulations governing decommissioning could also change. These changes could influence the decision on whether to proceed with DECON or SAFSTOR. The status of the spent fuel acceptance by the DOE may change, affecting the decision to store spent fuel in the spent fuel pool, on-site dry storage or off-site dry storage. Periodic estimate updates should be able to track the decommissioning trends without locking into a specific method or jeopardizing the availability of adequate decommissioning funds.

Q. Does this conclude your pre-filed verified direct testimony?

A. Yes, it does.

VERIFICATION

I, Roderick W. Knight, President of Knight Cost Engineering Services, LLC (KCES)], affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information, and belief.

Date: June 28, 2017

Roderick W.Knight

Decommissioning Study of the D. C. Cook Nuclear Power Plant

Prepared for Indiana Michigan Power Company

Knight Cost Engineering Services, LLC
January 21, 2016

Revision 0

TABLE OF CONTENTS

1.0 INTRODUCTION

1.1 DONALD C. COOK UNITS 1 AND 2 PLANT SITE

The Donald C. Cook Nuclear Power Plant (D.C. Cook Plant) is a nuclear-powered electrical generating facility located in Bridgman, Michigan. D.C. Cook Plant consists of two pressurized water reactors (PWR). Its electrical rating is 1084 MWe for reactor Unit 1 and 1107 MWe for reactor Unit 2. D.C. Cook Plant has been granted a twenty-year license extension by the Nuclear Regulatory Commission (NRC). Based on the terms of this extension, Unit 1 is scheduled for shutdown on October 25, 2034; Unit 2 is scheduled for shutdown on December 23, 2037. Units 1 & 2 are planned to be decommissioned in series following shut down.

This study is an update of the 2012 site-specific Decommissioning Cost Estimate of the D.C. Cook Nuclear Power Plant, Units 1 & 2, prepared for the Indiana Michigan Power Company (the Company). As such, it reflects site-specific plant information and cost factors. The most current decommissioning experience and logic have been incorporated into this estimate, including spent fuel acceptance rates, spent fuel storage issues, decommissioning methodologies, decommissioning management and waste disposal.

1.2 OVERVIEW OF THE SCENARIO

This study consists of one decommissioning scenario. This scenario includes the cost for the immediate decommissioning of the site (DECON), on-site storage of spent fuel, and clean removal. In addition, it includes the cost for the removal of the Independent Spent Fuel Storage Installation (ISFSI).

The cost estimate contained herein was developed based on a May 2015 configuration. It utilizes site-specific plant systems and building inventory recently generated based on current site configuration, drawings and component database. Costs have been determined for removal, packaging, transportation and disposal.

The decommissioning activities contained herein were previously developed and have been modified as required, with costs determined for each activity. The critical path schedule was previously developed and has been modified based on new spent fuel discharge assumptions and new and modified task durations. Period-dependent costs include utility staff, decommissioning general contractor staff, security, insurance, energy and others. Cost levels were determined based on specific periods or groups of activities per the schedule. Total period dependent costs were determined by the scenario-specific durations. Activity and period dependent costs were totaled to determine overall costs for each scenario.

The purpose of this study is to provide one cost estimate based the actual spent fuel storage conditions. The costs presented are for financial planning. All costs are in summer, 2015 dollars. All costs are based on the aforementioned spent fuel shipping and storage assumptions.

Utilizing the above estimating methodology, the cost for this scenario is $1,634,038,400. In addition there will be an annual cost of $4,912,700 per year of post decommissioning spent fuel storage and $56,952,300 for the eventual decommissioning of the ISFSI.

2.0 SUMMARY

Decommissioning is the safe removal of a facility or site from service and the reduction of radioactivity to a level that permits either the release of the property for unrestricted use and NRC license termination; or a restricted release of the property and NRC license termination.

2.1 DECOMMISSIONING ALTERNATIVES

The NRC allows three types of scenarios in estimating the decommissioning of a nuclear site, DECON, SAFSTOR and ENTOMB. The first, DECON, occurs soon after shutdown. It assumes that all systems, structures and contaminated site areas will be removed or decontaminated and that the facility's license will be terminated.

For the second alternative, SAFSTOR, preparations occur soon after shutdown. It assumes limited site decontamination and dismantlement; that all liquid will be drained from systems; that the facility will be placed in a safe and stable condition; that all spent fuel will be held in storage or shipped from the site; and that the site will be decontaminated and its license terminated within sixty years. This study does not consider the SAFSTOR scenario.

In the third alternative, ENTOMB, preparations occur soon after shutdown. It assumes limited site decontamination and dismantlement; that all liquid will be drained from systems; that the remaining radioactive systems and structures will be encased inside an entombment structure; that the facility will be continuously monitored; that spent fuel will be held in storage or shipped from the site; that the site will be decontaminated and license terminated within 60 years; and that most reactors will have radionuclides in concentrations exceeding the limits for unrestricted release after 100 years. This study does not consider the ENTOMB scenario.

Per NRC regulations, there are specific reporting requirements for decommissioning and spent fuel storage. Regulation 10 CFR 50.75, *Reporting and Recordkeeping for Decommissioning Planning, requires* a decommissioning report certifying that financial assurance will be available for decommissioning. The amount funded must be adjusted annually. A report on the status of funding must be submitted every two years. Costs not associated with decommissioning, such as spent fuel storage and clean removal costs, are specifically excluded.

Five years before license expiration or within 2 years after permanent shutdown, whichever occurs first, NRC regulation 10 CFR 50.54(bb) requires the licensee have a program to manage and provide funding for the management of spent fuel following permanent cessation until title to and possession of all of its spent fuel is transferred to the Department of Energy (DOE) for ultimate disposal in a repository. The licensee must demonstrate the actions will be consistent with NRC requirements and will be implemented on a timely basis according to these requirements.

On June 17, 2011, the NRC published a final rule amending its regulations to improve decommissioning planning. The rule became effective on December 17, 2012 and required compliance by March 31, 2013. This rule requires licensees to report additional details in their decommissioning cost estimate. To assist in the implementation of the new rule, the NRC revised NUREG-1757, "Consolidated Decommissioning Guidance, Financial Assurance, Recordkeeping and Timeliness," specifically volume 3. This volume applies to the timeliness and recordkeeping requirements for licensees under Title 10 of the Code of Federal Regulations (10 CFR) Parts 30, 40, 70, and 72. It also applies to financial assurance requirements for licensees under 10 CFR Parts 30, 40, 70, and 72. This volume does not apply to licensees under 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities." Regulatory Guide 1.159, Revision 1, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors," issued October 2003, provides guidance on financial assurance for these licensees. While the final rule applies to reactor licensees, like Cook, the guidance of NUREG-1757 is not directly applicable but does provide additional information useful in the development of this cost estimate.

While none of the above NRC regulations require Greenfield or clean system and structure removal costs, these costs may be required by local authorities to minimize liability. Removal of clean systems and structures may also be required to access contaminated components and structures. Therefore, Greenfield costs have been included in this study.

Table 2-1 provides a summary of the costs for this scenario. Costs are separated into the three cost categories based on the aforementioned spent fuel shipping and storage assumptions and have been determined based on the described estimating methodology.

TABLE 2-1
SUMMARY OF COSTS

DECON, Indefinite On-Site Dry Storage and Modified Spent Fuel Pool Systems				
Decommissioning Alternative	**Fuel Storage and Decommissioning Cost**	**Dormancy Period Cost**	**Delayed Dismantling Cost**	**Total Program Cost**
10 CFR 50.75(c)	$909,101,862	N/A	N/A	$909,101,862
10 CFR 50.54(bb)	$529,465,643	N/A	N/A	$529,465,643
Greenfield	$195,470,882	N/A	N/A	$195,470,882
			total:	**$1,634,038,387**
Annual ISFSI	$4,912,735 per year			**$4,912,735 per year**
ISFSI Decommissioning	$56,952,278			**$56,952,278**

3.0 DECOMMISSIONING COST ESTIMATING METHODOLOGIES

3.1 DECON

There are typically six periods associated with the DECON methodology of decommissioning cost estimating. Period one consists of decommissioning planning prior to shutdown. Period two involves post-shutdown preparations, including isolation of spent fuel; decontamination of the primary system; flushing and draining of all systems; implementation of cold and dark; and characterization surveys. Period three consists of removal of reactor internals and removal of the reactor vessel. The critical path task for period three is the removal, packaging, shipping and disposal of the reactor internals and the reactor vessel. Also in period three, the steam generators, pressurizers, contaminated systems and structures are removed, packaged, shipped and disposed of. Additionally, clean structures and systems are removed as they become unnecessary. In period four, the buildings undergo decontamination. Building decontamination includes decontamination of the reactor building(s), removal, packaging, shipping and disposition of spent fuel racks after spent fuel has been removed from the spent fuel pool, decontamination of the spent fuel pool and the balance of the auxiliary building(s), a formal site survey of any remaining buildings, and termination of 10 CFR Part 50 license. Period five consists of demolition of clean buildings. In this period, all remaining clean structures are removed with the exception of any required to support spent fuel storage. Period six consists of site restoration. In this period, the site is graded and landscaped to conform to the natural surroundings. Depending on the spent fuel storage assumptions, these periods may be separated by a wet spent fuel storage period, a dry spent fuel storage period, and/or a combination of both.

The estimate in this study utilizes the DECON methodology.

There are advantages to utilizing the DECON methodology. DECON provides sooner termination of the NRC license compared to SAFSTOR. Knowledgeable employees who are familiar with the site will still be available. There is no need for long-term security and surveillance. The DECON method provides a greater certainty of regulatory requirements due to the inherent uncertainty in trying to assess future regulatory requirements. Finally, the total cost will be lower as it is incurred in current dollars and there is no extended dormancy period. DECON offers similar advantages over ENTOMB, primarily avoiding the uncertainty and long-term surveillance costs likely associated with restricted release of the site. In addition, DECON allows more flexible site reuse compared to ENTOMB.

Disadvantages of the DECON methodology compared to SAFSTOR or ENTOMB include the following: the short time period that elapses following shut-down means less radioactive decay and therefore a higher worker dose. The initial cash outlay will be larger. There is time for funds to accrue, which means a larger present value; and work will have to be performed in proximity to the on-site storage of spent fuel.

3.2 SPENT FUEL ACTIVITIES

There are many uncertainties associated with the Department of Energy's (DOE) acceptance of spent fuel. The Department of Energy (DOE) originally contracted to begin accepting spent fuel from nuclear power plants no later than January 31, 1998. To date, no commercial spent fuel has been taken by the DOE under the contract. Many utilities have brought legal proceedings against the DOE for their breach of contract with the majority winning court ordered compensation. Recently, all activity at Yucca Mountain has been shutdown and, at least in the near term, has been removed as a potential spent fuel repository. It appears unlikely that that spent fuel shipments to a Federal repository will occur anytime in the foreseeable future. In light of this fact, all nuclear utilities should be prepared to store spent fuel on-site for a long period of time. This scenario assumes indefinite storage.

In October, 2011 the DOE reached a settlement agreement with Indiana Michigan Power Company in regards to their failure to commence acceptance of spent nuclear fuel and high level waste. The agreement allowed Indiana Michigan to recover costs incurred due to the DOE's failure through December 31, 2013. An Addendum to this settlement agreement was issued in January of 2014. The Addendum extended the termination date of the settlement to December 31, 2016. Allowable reimbursements are based on costs incurred above and beyond those that would have been incurred had the DOE performed according to the contract. But for DOE's failure to perform, Indiana Michigan's spent fuel allocations, those spent fuel assemblies that would have been taken by DOE, are identified in attachment 1 of the Addendum.

This scenario assumes all spent fuel will be transferred to an on-site ISFSI after shutdown. Dry storage will be required during operations to maintain full core discharge capabilities, including expanding the ISFSI, if needed. The ISFSI must be expanded, after shutdown, sufficiently to accommodate the long term storage of all spent fuel from both units. The storage system is anticipated to be licensed for both storage and transportation facilitating the eventual transfer to the DOE site.

It is assumed that spent fuel cannot be transferred to dry storage until it has cooled a minimum of seven years in the spent fuel pool. In order to minimize post-shutdown spent fuel storage costs the spent fuel island concept will be implemented. Modifications to the site will provide self-contained fuel pool cooling, cleanup, monitoring, control and electrical power systems. This will isolate the spent fuel pool from the remainder of the site and will allow decommissioning to continue safely on the balance of site. This option will provide the low cost option for the long term on-site storage of spent fuel.

Per ISFSI Licensing requirements, a 10 CFR part 72 license will be required in order to terminate the 10 CFR Part 50 license. Systems approved for use under the provisions of 10 CFR part 72 Subpart K, a Certificate of Compliance, may be used on a site with a 10 CFR part 50 license without a 10 CFR Part 72 Subpart C license. The process to obtain a 10 CFR Part 72 license will be simplified by utilizing a storage system with a Certificate of Compliance. For this reason, this study assumes the dry storage system utilized will have a Certificate of Compliance.

A site re-evaluation is not required to obtain the Part 72 subpart C ISFSI license if it is shown that original site findings have not changed. A re-evaluation would only be required if new information is available that alters the original findings. It is assumed that the system utilized for dry storage will meet or could be modified to meet the original site design conditions.

3.3 DECOMMISSIONING MANAGEMENT

The utility staff will retain certain of their ongoing functions during decommissioning, including the following:

- Shipment of low-level waste remaining from plant operations
- Radiological health and safety
- Security
- Quality assurance
- Health physics monitoring
- Defueling of the reactor
- Draining and de-energizing of all systems
- Continued safe on-site storage of spent fuel
- Management of the decommissioning general contractor.

The number of staff during each period depends on the major work planned for each period. Details are provided in section seven of this report.

While not directly applicable, consistent with the reasons stated in the NRC guidance of NUREG-1757, Vol. III, App. A, Section A.3.1, this study assumes that the utility will hire an experienced decommissioning general contractor (DGC) who will be responsible for performing the decommissioning activities. The DGC in turn will hire and be responsible for subcontractors hired to perform activities, such as primary system decontamination flush and large component removal. The number of staff during each period depends on the major work planned for each period. Details are provided in section seven of this report.

3.4 COLD & DARK

To simplify the removal of systems and structures, a "cold & dark" status will be implemented. The cold & dark status will allow component removal without individually verifying that each component has been de-energized. To implement cold & dark, all systems will be drained and electrical power to components will be removed as appropriate. After the spent fuel pool isolation has been completed, a new minimized control room will be constructed. Construction power will be supplied to the site for decommissioning and to operate essential loads with color coded wire. This process ensures that all energy sources are removed prior to the beginning of decommissioning activities, simplifying the removal process and greatly increasing safety during the decommissioning process.

3.5 DECONTAMINATION PROCEDURES

To facilitate the removal of contaminated large components, contamination control envelopes (CCE's) will be set up inside the reactor building. CCEs will have integral ventilation systems for contamination control and to maintain negative pressure. Cutting stations, including for underwater cutting, will be set up within the reactor building.

The reactor vessel internals will be removed from the vessel and transferred to the fuel transfer canal. Once in the transfer canal, they will be segmented and loaded underwater into shipping liners. The liner outer surfaces will be washed and loaded into shipping casks for transport to the disposal facility.

The reactor vessel will be cut into ring segments with each segment transferred to the fuel transfer canal. Here, each segment will be further segmented and loaded into shipping cask liners. The outer surfaces of the liners will be washed and then loaded into shipping casks for transport to the disposal facility.

With the exception of the upper shell, the steam generator will be removed intact. A steam generator transfer system and support equipment will be installed to remove the steam generator from the reactor building. A CCE and ventilation system, scaffolding, temporary lighting and shielding will also be installed. The insulation will be removed from the steam generators, followed by cutting of the main steam, feedwater and miscellaneous piping. Next the upper shell and components will be cut and removed. These will be surveyed, decontaminated and released if possible.

A steel plate will be welded to the top of the lower shell. The lower shell will be removed, transferred from the building, prepared for transport and transported to the disposal facility.

The pressurizer will be removed in a similar fashion, excluding segmentation.

The following process will be used for removal and disposal of contaminated systems, previously drained by the utility staff: Contaminated pipe and components will be cut free and segmented as necessary. The components will be transferred to a packaging area where a crew will package them, survey the containers and prepare the containers for shipment.

Clean pipe and components will be cut free and segmented when necessary. The components will be transferred to a packaging area where a crew will package the material into containers and prepare for them for shipment. It is assumed that clean waste will be disposed of at a local landfill.

With the exception of the reactor building interior, contaminated concrete surfaces will be decontaminated by partial surface removal. In some cases entire walls and/or floors will be removed. The remaining structures will be surveyed for conformance to release limits. Depending on the results of the survey, more decontamination may be required. Bulk removal of the reactor building interior floors and walls will be performed with all of the material being sent out for off-site processing. This leads to a large disposal volume; however, at a lower rate for bulk processing than for direct burial. In addition, there will be far less characterization and iterative decontamination.

Clean structures will be demolished using explosives and/or mechanical means and disposed of at a local landfill.

3.6 CONTINGENCY

Contingencies are applied to cost estimates primarily to account for unknown or unplanned events that experience tells us are likely to occur. These events include increased radioactive waste materials in volumes exceeding the amount anticipated; equipment breakdowns; weather delays; labor strikes, etc. Estimates are based on assumed values of cost, which in reality are subject to variability. The actual costs may be higher or lower than the estimated value; however, they usually go higher. The amount of contingency to be added is directly related to the level of detail and uncertainty contained in the estimate.

The U.S. Department of Energy (DOE) Cost Estimating Guide, DOE G 430.1-1, 3-28-97; defines contingency as follows: "Covers costs that may result from incomplete design, unforeseen and unpredictable conditions, or uncertainties within the defined project scope. The amount of contingency will depend on the status of design, procurement, and construction; and the complexity and uncertainties of the component parts of the project. Contingency is not to be used to avoid making an accurate assessment of expected costs."

DOE G 430.1-1 provides a recommended range of contingencies as a function of program design:

Time of Estimate	Contingency Range as a % of Total Estimate
Planning Phase	20-30
Budget	15-25
Title I	10-20
Title II	5-15

The AACE International Certification Study Guide, Second Edition - Revised, 2003, defines contingency as follows: "Contingency is a cost element of an estimate to cover a statistical probability of the occurrence of unforeseeable elements of cost within the defined project scope due to a combination of uncertainties, intangibles and unforeseen, highly-unlikely occurrences of future events based on management decisions to assume certain risks."

AIF/NESP-0036 "Guidelines for Producing Nuclear Plant Decommissioning Cost Estimates" (AIF) is another source for published contingency values. This document identifies contingencies for activities specific to nuclear power plant decommissioning. Except for system decontamination, reactor vessel removal and disposal and reactor internals removal and disposal, the contingencies presented in AIF are consistent with the values presented in DOE G 430.1-1 for a Budget/Title I estimate. The contingencies identified in AIF for system decontamination and reactor vessel and reactor internals removal and disposal are higher than the ranges identified in DOE G 430.1-1. This is in part due to the lack of actual decommissioning work performed during the time period the AIF document was published.

While not directly applicable to a Part 50 reactor license, the NRC guidance of NUREG-1757, Vol. III, App. A, Section A.3.1, states that a contingency factor of 25% is normally appropriate. "Because of the uncertainty in contamination levels, waste disposal costs, and other costs associated with decommissioning, the cost estimate is required to apply an 'adequate' contingency factor. In general a contingency of 25 percent applied to the sum of all estimated decommissioning costs should be adequate, but in some cases, a higher contingency may be appropriate." The guidance goes on to recognize that "Proposals to apply the contingency only to selected components of the cost estimate, or to apply a contingency lower than 25 percent, should be approved only in circumstances when a case-specific review has determined that there is an extremely low likelihood of unforeseen increases in the decommissioning costs." For the reasons developed below, this study is an example of circumstances where a case-specific review has determined that applying a contingency lower than 25 percent to some elements of the cost estimate is appropriate.

An estimate of the nature developed for D. C. Cook would be considered somewhere between a Budget estimate (based on conceptual design) and a Title I (based on more detailed site specific design). As such, an overall contingency in the 15% to 25% range would be appropriate. Knight Cost Engineering Services, LLC (KCES) has determined contingency values specific to DC Cook utilizing the information presented in AIF and consistent with DOE G 430.1-1. There are a number of large scale decommissioning projects in progress or nearing completion. The DC Cook decommissioning cost estimate incorporates the lessons learned from these projects. As such, costs can be estimated with a greater degree of confidence than was true at the time AIF was published. This increased level of confidence allows for a downward adjustment to the recommended contingency where applicable. Other cost elements, particularly with regard to the reactor vessel segmentation, are less well known and contingency up to 50 percent is appropriate. The following table provides a summary of the contingency values that were applied to each activity for each cost category.

TABLE 3.1

	Staff Labor	Craft Labor	Equip & Mtls	Pkging	Trans-portation	Clean Disposal	Contam-inated Disposal	Energy	Other
Engineering and Project Management	15%								
Contaminated removal		25%		10%	15%		25%		
Reactor Vessel and Internals		50%		25%	25%		50%		
Clean removal		15%		10%	25%	10%			
Supplies and consumables			25%						
Other								15%	15%

There is some variation associated with the contingency analysis for on-site spent fuel storage. The activity costs associated with spent fuel storage, such as the purchase and construction of the ISFSI, the modification of the spent fuel pool and the transfer of spent fuel pool to the ISFSI are subject to many of the unknown or unplanned occurrences for which contingency is based. As such, the above methodology will be applied. During periods of spent fuel storage only, either wet or dry, the operating costs of the spent fuel storage facility include only a ten percent contingency because of the higher degree of knowledge and confidence in the factors comprising the operation of the wet or dry storage facility. Any variability in the duration of the fuel storage period due to failed DOE schedules is excluded from the contingency.

4.0 ASSUMPTIONS

Following is a list of assumptions developed by KCES in completing this study. These assumptions are based on the most current decommissioning methodologies and site-specific considerations.

1. **Component quantities** with the exception of pipe, conduit, cable tray and duct lengths, were developed from directly from the plan EDB system. Pipe, conduit, cable tray and duct lengths were used as is from the previous estimate.

2. **Structure inventory quantities** were developed for this estimate from general arrangement drawings and the site walkdown.

3. **The utility staff** is assumed to be the same size at the time of Unit 2 shutdown as it was in July, 2015.

4. **Utility staff positions and costs** were supplied by the Company and represent July, 2015 salary and benefit data

5. **Subcontractor base labor rates and fringe benefits** were supplied by AEP for most crafts. These rates were current as of June, 2015. The overhead and profit structure for these rates was developed by KCES.

6. **Craft labor rates** for positions not supplied by the Company were determined by KCES.

7. **Activity labor** costs do not include any allowance for delays between activities, nor is there any cost allowance for craft labor retained on-site while waiting for work to become available.

8. All **skilled laborers** will be supplied by the local union hall and hired by the Decommissioning General Contractor (DGC).

9. The **professional personnel** used for the planning and preparation activities will be paid per diem at the rate of $142.00/day. Since the skilled laborers are being supplied by local union hall they will not be paid per diem.

10. The cost for **Utility personnel** assisting the DGC to develop decommissioning activity specifications is included in the Utility Staff costs.

11. **Health Physics technicians** used during vessel and internal removal will be supplied by the Utility Staff.

12. **The DGC staff salaries**, including overhead and profit, were determined by KCES.

13. **Transportation** costs are based on actual mileage from D. C. Cook to each disposal or processing facility utilized in the estimate.

14. **Class B & C radioactive waste base disposal costs** are based on actual out of compact disposal rates and fees incurred at the WCS facility in Andrews, TX. In addition, the disposal costs of the Greater Than Class C waste, e.g., the core baffle and lower core grid plate, include present day curie surcharges as imposed at the WCS facility to more accurately reflect handling costs for highly radioactive material.

15. **Class A waste** will be disposed of at the Energy*Solutions* facility in Utah, Energy*Solutions* metal melt facility in Tennessee or the Studsvik processing facility in Tennessee, which Energy*Solutions* acquired in 2014. Waste is assumed to be transported to the lowest cost facility for which it qualifies. Further details on these processes are presented in Section 8.1.

16. **Clean waste** is assumed to be disposed of at a local landfill at a cost of $90.00 per ton.

17. It is assumed that **all radioactive waste** generated during operations and stored on-site will be disposed of prior to shutdown. The cost of disposal of this material is considered an operating expense and is assumed not to be a decommissioning cost.

18. **Greater than Class C waste** will be removed from the reactor vessel, segmented and packaged in containers of similar size and shape to the spent fuel assemblies. The containers will be stored in the spent fuel pool or transferred to the ISFSI. The additional containers are assumed to be shipped offsite with the spent fuel and are included in the spent fuel shipping analysis. Eighty-four containers will be filled per unit for both scenarios.

19. **All costs** used in these calculations were current on July, 2015.

20. The costs of all **required safety analyses and safety measures** for the protection of the general public, the environment, and decommissioning workers are included in the cost estimates.

21. All post shutdown costs necessitated by the presence of **stored spent fuel** are presented separately.

22. It is assumed that **Unit 1 will shut down** in October, 2034 and that **Unit 2 will remain operational** until December 2037.

23. **On-site dry storage** will utilize the Holtec Vertical Concrete Casks (VCC) and Multi-Purpose Canister (MPC) system. Each MPC is designed to store and transport 32 spent fuel assemblies. Separate overpacks will be used for transportation and disposal.

24. It is assumed that spent fuel will cool seven years in the spent fuel pool prior to being transferred to the ISFSI or shipped off site.

25. Only the costs for the **expanded storage pad**, **canister and overpacks** projected to be purchased after Unit 1 shutdown are included in this study as a spent fuel storage

expense. All canisters and overpacks required during operations, in order to maintain full core discharge capabilities, are assumed to be an operations expense. The cost per canister and storage overpack is estimated to be $2,000,000, including closure services.

26. **The Unit 1 and Unit 2 reactor vessel and internals** will be removed sequentially.

27. **The Unit 1 and Unit 2 reactor vessel and internals** are considered identical.

28. **Vessel and internals curie estimates** were derived from the values for the Reference PWR vessel and internals in NUREG/CR-0130. These values were adjusted for MWT rating, weight and decay period.

29. While there will in all likelihood be some level of property tax after shutdown, this study does not attempt to estimate the amount. It has been assumed for purpose of this study that **property taxes** for the D.C. Cook Plant will be zero after shutdown. This issue will be addressed as more information becomes available.

30. No **PCBs** will be on-site at shutdown.

31. It is assumed that all **asbestos insulation** will have been removed during the operating life of the plant.

32. **Clean building walls and foundations** more than three feet below grade may be left in place if there are no voids.

33. KCES has assumed that a site specific 10 CFR Part 72 license will be required for the balance of the dry storage period prior to terminating the 10 CFR Part 50 operating license.

34. The decommissioning will be performed under the **current regulations.** These regulations require a Post-Shutdown Decommissioning Activities Report (PSDAR) to be submitted prior to or within two years of after shutdown. In addition, certificates for permanent cessation of operations and permanent removal of fuel from the vessel must be submitted to the NRC 90 days after the PSDAR submittal. Major decommissioning activities that meet the criteria of 10 CFR Part 50.59, may be performed provided NRC agrees with the PSDAR.

35. The VCCs and storage pad may have some level of activation, as such the material will be removed and transported to one of the Energy*Solutions* processing facilities in Tennessee .

5.0 SCENARIO DESCRIPTION

Utilizing the above described estimating methodology cost for this scenario is $1,634,038,400. In addition there will be an annual cost of $4,912,700 per year of post decommissioning spent fuel storage and $56,952,300 for the eventual decommissioning of the ISFSI. The assumptions pertinent to this scenario are described below.

5.1 DECON WITH INDEFINITE ON-SITE DRY STORAGE

This scenario includes Unit 1 shutdown on Oct 25, 2034 and Unit 2 on Dec 23, 2037. The transfer of spent fuel remaining in the spent fuel pool to the dry storage facility will begin in 2039. The existing ISFSI will be expanded to accommodate all spent fuel remaining on-site. With the exception of the last core load of fuel assemblies, transfer of all remaining fuel to the ISFSI will be completed seven years after shutdown. The transfer of the last core load of 193 assemblies and a few remaining assemblies will occur immediately after the required seven year cooling period. The site will remain as an Independent Spent Fuel Storage Installation indefinitely.

The spent fuel pool will be modified immediately after Unit 2 shutdown to isolate it from the remainder of the facility. The capital cost of the skid mounted pool support systems package is included in this estimate. This will allow decommissioning to proceed exclusive of the spent fuel pool. Once all spent fuel has been removed from the spent fuel pool, the spent fuel pool island will be decommissioned. As soon as all spent fuel is transferred to dry storage, the balance of the D.C. Cook Plant will be decommissioned. All spent fuel will be stored on-site in Holtec's VCC and MPC system.

The six sequential periods in this scenario and the major activities occurring in each are as follows:

Period	Description	Period Duration, Months
1	BETWEEN SHUTDOWN OF UNIT 1 AND SHUTDOWN OF UNIT 2 • Planning for spent fuel pool modifications • Planning for cold and dark • Planning for primary systems flush • Select DGC • Planning for decommissioning	38
2	POST-SHUTDOWN ACTIVITIES • Transfer spent fuel from pool to the ISFSI • Modification of spent fuel pool systems • Primary system decontamination flush	12

- Flush and drain non-essential systems
- Perform characterization survey
- Implement cold and dark
- Vessel and Internals removal preparations

3	REMOVAL OF MAJOR COMPONENTS • Transfer spent fuel from pool to the ISFSI • Removal of Unit 1 and Unit 2 reactor vessels and internals • Removal of Unit 1 and Unit 2 steam generators • Removal of Unit 1 contaminated systems • Remove Unit 1 clean systems • Decontaminate Unit 1 Reactor Building • Begin Unit 1 and Unit 2 structures decontamination	42
4	DECON BALANCE OF SITE • Removal of Unit 2 contaminated systems • Remove Unit 2 clean systems • Decontaminate Unit 2 Reactor Building • Remove spent fuel racks • Decontaminate spent fuel storage building • Completion of Unit 1 and Unit 2 structures decontamination • Final site survey of reactor plant confirming satisfactory removal	38
5	CLEAN STRUCTURES DEMOLITION • Demolition of decontaminated Unit 1 and Unit 2 structures	18
6	RESTORATION OF PLANT SITE • Backfill, grading and landscaping of Unit 1 and Unit 2 sites	2

In this scenario, decommissioning and site restoration will be complete approximately 112 months or 9.3 years after Unit 2 shutdown. Spent fuel will remain on-site indefinitely. The cost for the eventual decontamination and removal of the ISFSI is included in the estimate.

6.0 SCHEDULES

A scenario-specific schedule has been developed for this study. The schedule is based on some combination of the following assumptions:

- DECON
- Spent fuel shipping start date
- Spent fuel shipping rate
- Construction and maintenance of on-site dry storage facility

The first step in determining each schedule is assessment of the spent fuel disposition. The spent fuel disposition schedule will have a major influence on the overall schedule critical path. The spent fuel disposition analysis will then be combined with the decommissioning activities to determine the overall project schedule.

Activity durations are determined based on the unit cost factor approach. Once the plant material inventory has been determined specific unit rates for cost, man hours and schedule hours for a specific activity, such as surface decontamination, are applied to the inventory. From this calculation the removal or decontamination cost, total man hours and total schedule hours are determined for an activity. The schedule hours are then entered into the schedule to determine project duration. The schedule will be divided into multiple periods depending on the activities occurring during that time period. The separation into multiple periods allows for better control in determining the period dependent costs such as staffing, insurance and security.

The spent fuel disposition analysis for Unit 1 and Unit 2 are presented in Table 6.1. This scenario assumes an indefinite on-site storage period. A detailed decommissioning schedule, based upon this spent fuel transfer schedule and a critical path analysis of the decommissioning activities, is presented in Appendix A.

6.1 DECON WITH ON-SITE DRY STORAGE AND NO SPENT FUEL SHIPPING

Spent fuel is assumed to remain on-site in dry storage indefinitely. The schedule of spent fuel movements is reflected in Table 6.1. The detailed project schedule is present in Appendix A. The decommissioning schedule has been optimized within the limitations imposed by the spent fuel storage requirements. Program periods and durations for this scenario are as follows:

Period	Description	Duration, months
1	U1 & U2 Decommissioning Planning Cost:	38
2	Post-Shutdown Activities Costs:	12
3	Vessel and Internals Removal Costs:	42

4	Decontaminate Balance of Site Costs:	38
5	Clean Structure Demolition Costs:	18
6	Restore Site Costs:	2
7	Dry Storage (Indefinitely)	
8	Eventual decontamination and removal of ISFSI	21

Decommissioning of the site will be complete in 2047, which is 112 months after the shutdown of Unit 2. Spent fuel will remain on site in dry storage indefinitely.

TABLE 6.1
SPENT FUEL SHIPPING SCHEDULE

Year	Unit 1 Fuel Discharged	Unit 2 Fuel Discharged	Assemblies To DOE	Total Assemblies & other items on Site	Assemblies to Dry Storage	Total Assemblies in Dry Storage	Pool Locations Occupied
2015		84 note 1		3684	512	896	2788
2016	89	89		3862	0	896	2966
2017	89	0		3951	0	896	3055
2018	0	89		4040	512	1408	2632
2019	89	89		4218	0	1408	2810
2020	89	0		4307	0	1408	2899
2021	0	89		4396	512	1920	2476
2022	89	89		4574	0	1920	2654
2023	89	0		4663	0	1920	2743
2024	0	89		4752	384	2304	2448
2025	89	89		4930	0	2304	2626
2026	89	0	0 note 3	5019	0	2304	2715
2027	0	89	0	5108	384	2688	2420
2028	89	89	0	5286	0	2688	2598
2029	89	0	0	5375	0	2688	2687
2030	0	89	0	5464	320	3008	2456
2031	89	89	0	5642	0	3008	2634
2032	89	0	0	5731	0	3008	2723
2033	0	89	0	5820	0	3008	2812
2034	193	89	0	6102	0	3008	3094
2035		0	0	6102	0	3008	3094
2036		89	0	6191	0	3008	3183
2037		193	0	6384	0	3008	3376
2038			0	6384	0	3008	3376
2039		42 note 2	0	6426	320	3328	3098
2040		84	0	6510	384	3712	2798
2041		42	0	6552	512	4224	2328
2042			0	6552	512	4736	1816
2043			0	6552	704	5440	1112
2044			0	6552	704	6144	408
2045			0	6552	408	6552	0
2046			0	6552		6552	0

NOTES:
1. Discharge supplied by AEP 5/5/15.
2. 84 spent fuel baskets loaded with GTCC will be discharged into the spent fuel pool, from each unit, during internals removal.
3. Spent fuel will remain on-site indefinitely.
4. Assemblies to dry storage determined by AEP through, 2033. Assemblies to dry storage after Unit 1 shutdown determined by KCES
5. Max number of casks required: 205
6. Casks purchased after shutdown 111

7.0 PROJECT MANAGEMENT

There are three components to project management during decommissioning, Utility Staff (staff), Decommissioning General Contractor Staff (DGC) and Security. Each of these is further broken down into that required for decommissioning and that required for spent fuel storage. The person levels for each are specific to each decommissioning period.

7.1 UTILITY STAFF

The staff size at Unit 1 shutdown is assumed to be the same size and composition as it was in the spring of 2015. Immediately after Unit 1 shutdown, the staff is reduced approximately 33%, severance payments for the severed personnel are included in period one of this study. The majority of the remaining staff is attributed to the operation of Unit 2. Upon shutdown of Unit 2 this staff is reduced to the level required for decommissioning operations and spent fuel storage, the severance payments for the severed personnel are included in period two of this study. Severance payments are tracked through the decommissioning and all costs are included in this study. All severed employees will receive a severance package based on the existing severance policy.

There are two components to the staff, decommissioning and spent fuel storage. The majority of the staff during the early part of the decommissioning process will be attributed to decommissioning. A staff level of 11.5 full time employees (FTE) will be required during period 1, between Unit 1 and Unit 2 shutdown. Upon shutdown of Unit 2, period 2, approximately 145 FTEs will be required to prepare the site for decommissioning, including the spent fuel pool, security and control room modifications. Once these modifications have been made the staff will be reduced to 96 FTEs to support the reactor internals and reactor vessel removal, period 3. The staff will be further reduced to 78 FTEs, 7 FTEs and 3 FTEs for period 4 site decontamination, period 5 structures removal and period 6 site restorations, respectively.

During the decommissioning process there is a need to manage the safe operations of the spent fuel storage facilities, whether spent fuel is in wet storage or dry storage. The Utility staff will maintain responsibility for these actions. Spent fuel will remain in the spent fuel pool for a minimum of seven years. Also, there is an existing ISFSI, required during operations to maintain full core off load capabilities. As such, there are two on-site spent fuel storage scenarios, wet and dry storage in operations at the same time and dry storage only. During the wet and dry storage periods the Utility staff will be 33 FTEs and 14.25 during dry storage only. There will be some fluctuation in these staffs due to sharing of upper management personnel with the decommissioning staff.

7.2 DECOMMISSIONING GENERAL CONTRACTOR

The DGC is assumed to have no role in the post shutdown management of the spent fuel storage facility. Upon selection of a DGC contractor, the contractor will begin to mobilize on site. A DGC staff of 27 FTEs is assumed to be on site during the last 12 months of period 1, between Unit 1 and Unit 2 shutdown. A DGC staff of 76 FTEs will be on site to prepare for decommissioning during period 2 site preparations. The DGC staff will be increased to 89 FTEs to support the reactor internals and reactor vessel removal, period 3. The DGC staff will be reduced to 76 FTEs, 34 FTEs and 15 FTEs for period 4 site decontamination, period 5 structures removal and period 6 site restorations, respectively.

7.3 SECURITY

There are two components to the security staff, decommissioning and spent fuel storage. The majority of the security staff during the early part of the decommissioning process will be attributed to decommissioning. An apportionment of the full security staff is allocated to Unit 1 during period 1, between Unit 1 and Unit 2 shutdown, estimated to be 5 full time employees (FTE). Upon shutdown of Unit 2, period 2, approximately 72 FTEs will be required during preparations for decommissioning. Once modifications have been made to the spent fuel pool, security and control room the security staff will be reduced to 32 FTEs to support the reactor internals and reactor vessel removal, period 3 and site decontamination, period 4. The staff will be further reduced to 7 FTEs and 2 FTEs for period 5 structures removal and period 6 site restorations, respectively.

During the decommissioning process there will be a need to manage the safe operations of the spent fuel storage facilities, whether spent fuel is in wet storage or dry storage. A dedicated security staff will be assigned to both the wet and dry storage facility. Spent fuel will remain in the spent fuel pool for a minimum of seven years. There is an existing ISFSI, required during operations to maintain full core off load capabilities. As such, there are two on-site spent fuel storage scenarios, wet and dry storage in operations at the same time and dry storage only. During the wet and dry storage periods the security staff will be 20 FTEs and during dry storage only the security staff will consist of 13 FTEs. A security staff of 13 FTEs is attributed to spent fuel storage during the ISFSI removal.

The following Table 7-1 is a summary of the utility staff, DGC and security staff levels required.

7.4 DECON WITH INDEFINITE DRY STORAGE

Table 7.1 summarizes the staff level for Decommissioning and Table 7.2 summarizes the staff levels for spent fuel storage as defined above, by period.

TABLE 7-1 DECOMMISSIONING STAFF SUMMARY

Position:	1	2	3	4	5	6	7
Health Physics	2.25	29	24	24	0	0	0
Engineering	1.25	20	11	10	2	1	0
Maintenance Services	2.75	19	5	5	3	0	0
Operations	0.75	38	14	5	0	0	0
Projects	3.25	13	29	22	0	0	0
Administration	1.25	26	13	12	2	2	0
	11.5	**145**	**96**	**78**	**7**	**3**	**0**
DGC	27	76	89	76	34	15	
Security Guards	5	72	32	32	7	2	

TABLE 7-2 SPENT FUEL STORAGE STAFF SUMMARY

Position:	1	2	3	4	5	6	7	8
Health Physics	0	5	5	5	1.25	1.25	1.25	4
Engineering	0	1	1	1	0	0	0	0
Maintenance Services	0	5	5	5	2	2	2	2
Operations	0	13	13	13	5	5	5	6
Projects	0	0	0	0	2	2	2	1
Administration	0	9	9	9	4	4	4	4
	0	**33**	**33**	**33**	**14.25**	**14.25**	**14.25**	**17**
DGC	0	0	0	0	0	0	0	14
Security Guards	0	24	20	20	13	13	13	13

8.0 WASTE DISPOSAL

8.1 LOW LEVEL WASTE DISPOSAL BACKGROUND

The Low-Level Waste Policy Act (LLWPA), passed by Congress in 1980 and the Low-Level Waste Policy Amendments Act of 1985 encouraged states to form compacts for the disposal of low-level radioactive waste. The Acts made each state responsible for disposing of their own radioactive waste. The formation of compacts allowed states to limit their disposal facility to compact members thereby limiting the amount of waste accepted. On the other hand, the Acts also required that states not participating in the process would be required to take title to waste generated within that state. This provision was overturned by the U. S. Supreme Court in 1992 thus eliminating the need for states to develop their own disposal facility, including those already in a compact. The compact process has not resulted in the expected regionalization of low level radioactive waste disposal; to date there has been just one new disposal facility licensed to accept all low level radioactive waste, including Class A, B & C.

There are currently three facilities licensed to accept all low level radioactive waste: the Barnwell, South Carolina facility operated by Energy*Solutions*, LLC; the Waste Control Specialists, LLC (WCS) facility in Andrews, TX and the Hanford, Washington facility operated by U. S. Ecology. There is one other site in Clive, Utah owned and operated by Energy*Solutions*, LLC; however, this facility is currently licensed to accept only Class A radioactive waste. As of July 1, 2008 the Barnwell facility will only accept waste from the Atlantic Compact states. The Atlantic Compact member states include South Carolina, Connecticut and New Jersey. The Hanford facility only accepts waste from the Northwest Compact and the Rocky Mountain Compact; this has been the case since 1993. The Northwest Compact and Rocky Mountain Compact member states include Alaska, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington and Wyoming. While the WCS facility is the compact disposal facility for Texas and Vermont it will accept waste from out of compact. WCS is licensed to accept Class A, B and C radioactive waste, as such this estimate assumes that Class B & C waste will be disposed of at this facility with the costs based on the current rate structure for out of compact waste.

8.2 CLASS A WASTE DISPOSAL

There are currently multiple options for the disposition of Class A waste. These include metal melt, direct burial and waste processing. Table 8-1 provides a summary of waste disposition options for Class A waste and their unit rates considered in this estimate. KCES assumes that each waste stream will be transported to the least cost option for which it qualifies. Packaging and transportation costs have been calculated based on these specific locations.

Table 8-1
Class A Waste Disposal Options

Description	Disposal Cost, $/cu. ft.
ENERGY*SOLUTIONS* disposal	$171.84 per cubic foot
WCS disposal	$208.79 per cubic foot
BSFR processing	$0.25 per pound

KCES assumed that the reactor building internal floors and walls will be removed in bulk and sent for processing to a BSFR facility. This approach will produce a large volume of waste compared to the traditional decontamination, survey and release methodology but at a lower rate. In addition, the approach will reduce the amount of characterization and iterative decontamination. Other contaminated structures will follow the decontamination, survey and release approach due to the smaller areas of potentially contaminated surfaces.

The steel in the vertical concrete casks and the storage pad for the ISFSI are assumed to be potentially activated. The entire volume of the VCCs and pad will be sent to the BSFR facility in Tennessee for processing. Sending the entire volume of this material for processing will eliminate the time consuming processing of separating, surveying and repeating as necessary. The remainder of the material associated with the ISFSI will be removed as clean material.

8.3 CLASS B & C WASTE DISPOSAL

As discussed above, the WCS facility is licensed to accept Class B and C waste. This study assumes that all Class B & C waste will be disposed of at WCS. There is currently only a published fee and surcharge structure for in compact generators. Based on guidance from WCS personnel, increasing the published fees and surcharges by 20% would be representative of the rates that would be charged to out of compact generators. The base disposal rate for Class B & C waste is currently $2,680/cubic foot. This rate was provided by AEP.

Additionally, there is a dose rate surcharge and a millicurie charge that must be added. The basic millicurie charge is $0.55 per millicurie up to $220,000 per shipment. There is also a weight surcharge, up to $20,000 per shipment; a dose rate surcharge, up to $400 per cu. ft.; an irradiated hardware there is an additional surcharge of $75,000 per shipment and a cask handling surcharge of $2,500 per cask. Finally there are State and County fees of 5% each. These rates appear to be unchanged from 2012. This estimate includes all applicable surcharges and fees.

8.4 DISPOSAL OF WASTES GREATER THAN CLASS C

While waste identified as Class A, B and C, according to 10 CFR 61, may be disposed of at a near-surface disposal facility, certain components may exceed the radionuclide concentration limitations for 10 CFR 61 Class C waste. These components cannot be disposed in a near-surface radioactive waste disposal facility based on 10 CFR 61 definitions. They will have to be transferred to a geologic repository or a similar site approved by the NRC.

The KCES site-specific classification of radioactive wastes for the D.C. Cook Plant identified that the Spent Fuel Assemblies and two components within each reactor vessel (the Core Baffle and the Lower Core Grid Plate) will exceed Class C limitations. Like the spent fuel assemblies, the reactor vessel components will be stored with the spent fuel either in wet or dry storage. Here they will wait for transportation to a DOE geologic disposal facility for disposal. The costs for disposing of these components was estimated based upon the maximum curie surcharges currently in effect at the WCS disposal facility. Prior to placing in storage with the spent fuel, these components will be segmented and the pieces placed into spent fuel sized containers, it is estimated that 168 containers will be generated from the two units.

8.5 RADIOACTIVE WASTE VOLUMES PER 10 CFR 61 CLASSIFICATIONS

KCES has determined the classifications of radioactive wastes resulting from decommissioning the D.C. Cook Plant. The radioactive waste associated with each decommissioning activity is based upon the site-specific decommissioning calculations prepared for this cost estimate. The total volumes of 10 CFR 61 wastes for Units 1 and 2 are presented in Table 8.2. These volumes represent waste volumes generated at the site, for both units, excluding the waste generated by removing the ISFSI.

Table 8-2
10 CFR 61 Radioactive Waste Volumes (cubic feet)

Class A	3,622,768
Class B	5,480
Class C	2,344
Greater Than Class C	1,512
Total:	3,632,104

Waste associated with the removal of the ISFSI, is identified in Table 8-3 below.

Table 8-3
10 CFR 61 Radioactive Waste Volumes (cubic feet)

ISFSI	534,981

8.6 PROJECTION OF NON-RADIOACTIVE WASTE QUANTITIES

KCES has included the cost for disposal of all non-contaminated waste at a local landfill. As seen in the Maine Yankee decommissioning, on-site use of concrete rubble to fill below grade voids can be problematic. Maine Yankee originally intended to utilize remediated concrete to fill below grade voids. Many felt that this would essentially be considered on-site disposal of radioactive material since the concrete, although below the limits specified in the License Termination Plan (LTP), might still be slightly radioactive. Maine Yankee decided to eliminate potential legacy waste by transporting and disposing of this material in a licensed landfill. For this reason KCES has assumed that all non-contaminated waste, including pipe and components will be disposed of in a licensed landfill at a rate of $0.045 per pound. Table 8-4 presents the total volumes of non-contaminated waste resulting from the decommissioning program.

Table 8-4
Non-Contaminated Waste (pounds)

Structures	1,006,158,339
Systems	45,885,045

9.0 COST SUMMARIES

9.1. ESTIMATING APPROACH

The estimating methodology utilized in the development of the cost estimate in this study is consistent with that presented in both *Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates*, AIF/NESP-036, May 1986 and *Revised Analysis of Decommissioning for the Reference Pressurized Water Reactor Power Station*, NUREG/CR-5884, PNL-8742, November 1995. Specifically the estimating methodology used by KCES herein is based on the Unit Cost Factor (UCF) approach. In addition, current experience from recently completed decommissioning projects has been considered in developing the estimating methodology.

KCES has developed a database of unit cost factors specific to the work activities associated with decommissioning a nuclear power reactor such as the cutting of a section of six inch contaminated pipe. These UCFs define the duration of an activity on a unit basis, including for the example above, contamination control set-up, cutting, capping pipe ends, removal from area, removal of contamination control and productivity adjustment factors. From the durations, local labor rates and equipment and material costs, removal costs are determined, including associated consumable costs. Material waste volumes, man-hours, disposal costs, packaging costs and transportation costs are also determined, again on a unit basis for each UCF. Each UCF is adjusted based on site specific factors such as labor rates, transportation costs and disposal rates.

The first step in developing the site specific activity removal and disposal cost is to develop a site specific plant inventory. KCES developed the structure inventory for this estimate from current site specific drawings supported by a site walkdown. The systems inventory was developed from the site component database supported by referencing flow diagrams and the USAR. The plant system inventory list was separated into contaminated and non-contaminated components and unique unit cost factors were developed for each radiological condition. The site specific material quantities are then multiplied by the appropriate UCF to determine the total activity cost and removal man-hours.

The decommissioning activities are inserted into a project schedule and sequenced based on order of performance. The schedule hours, as determined by the UCFs for each activity are then incorporated in the project schedule to determine the critical path of the project. The schedule is then divided into several periods. Each period is defined by an activity or group of activities requiring a specific amount of oversight or support. For instance, during the vessel internals and reactor vessel removal activities the Utility staff, DGC staff and security staff are required to be maintained at a certain level. Once these activities are complete the levels may change based on the controlling activities.

Period dependent costs are those costs that are not specific to the decommissioning activities but are required as support. Costs such as those for the Utility staff, DGC staff, security staff, insurance, health physics supplies and energy are calculated on a monthly basis based on the major activities defining a given period. These monthly costs are then multiplied by the duration of the respective period to determine period dependent costs. The activity and period dependent costs are then summed to determine total decommissioning costs.

These activity and period dependent costs are either spent fuel storage related (10 CFR 50.54(bb)), decommissioning related (10 CFR 50.75(c)), greenfield (g) or a combination of the three. KCES has separated costs in each of these categories during the estimating process.

A detailed decommissioning cost table is presented in Appendix B and is summarized below. All costs are presented in 2015 dollars. The summarized costs include contingency.

9.2 DECON WITH INDEFINITE ON-SITE DRY STORAGE

The total cost for this scenario is **$1,634.0** million fixed and **$4.9** million annual, as shown in Table 9.1. A total of $529.5 million fixed is attributed to the preparation and transfer of spent fuel to the ISFSI. An annual cost of $4.9 million will be incurred for the continuing maintenance and surveillance of the ISFSI. A total of $909.1 million is attributed to the decommissioning, and $195.5 million for greenfield. For this scenario, there is a large fixed cost required for the design, license, cask procurement, and construction and installation of the dry storage facility. There are also annual surveillance costs, NRC license fees and NRC inspection fees. The cost attributed to the operation and maintenance of the spent fuel pool has been optimized by minimizing the spent fuel support systems. There is an additional cost of $57.0 million for the eventual decontamination and removal of the ISFSI.

An ISFSI will have been constructed during operations in order to maintain full core offload capabilities in the spent fuel pool. The existing facility will be expanded shortly after Unit 1 shutdown to accommodate the long term storage of spent fuel. The transfer of the spent fuel assemblies remaining in the spent fuel pool at shutdown, to the ISFSI, will begin just after Unit 2 shutdown. This transfer will proceed at a rate sufficient to allow the spent fuel pool to be empty approximately 7.5 years after Unit 2 shutdown. The maximum number of spent fuel assemblies stored at the ISFSI at any time will be approximately 6,552 requiring 205 storage casks, 111 of which will have been purchased to maintain full core offload capability and are an operations expense. In addition to the spent fuel, 168 spent fuel size containers loaded with GTCC will be stored at the ISFSI, requiring an additional six casks.

The existing ISFSI and infrastructure will have to be expanded to accommodate the post shutdown transfer of spent fuel. The additional pad and infrastructure will cost approximately

$135 million, before contingency. It is assumed that the Holtec vertical storage system will be utilized in the ISFSI at a cost of $2,000,000 per 32 assembly PWR canister and overpack, including welding services. All casks purchased during operations to maintain full core offload capability would be expended prior to Unit 1 shutdown, so would not be an expense of the decommissioning trust. A total of 111 casks will be purchased after Unit 2 shutdown at a cost of $222.0 million, before contingency. All costs associated with the operation of the ISFSI such as staff oversight, maintenance costs, insurance costs, etc. are included in the 10 CFR 50.54(bb) costs.

TABLE 9.1

PERIOD	DESCRIPTION	50.75(c) Cost	50.54(bb) Cost	Greenfield Cost	Total Cost
1	U1 & U2 DECOMMISSIONING PLANNING COST:	$50,041,436	$173,086,201		$223,127,637
2	POST-SHUTDOWN ACTIVITIES COSTS:	$126,358,434	$153,329,659		$279,688,093
3	VESSEL AND INTERNALS REMOVAL COSTS:	$487,208,650	$169,529,044	$27,958,874	$684,696,569
4	DECONTAMINATE BALANCE OF SITE COSTS:	$245,493,342	$27,478,897	$20,813,681	$293,785,921
5	CLEAN STRUCTURE DEMOLITION COSTS:		$5,493,075	$144,693,529	$150,186,604
6	RESTORE SITE COSTS:		$548,766	$2,004,798	$2,553,564
	TOTAL COSTS:	$909,101,862	$529,465,643	$195,470,882	$1,634,038,387
7	ANNUAL DRY STORAGE		$4,912,735		$4,912,735
8	ISFSI DECONTAMINATION AND REMOVAL		$56,952,278		$56,952,278

10.0 REFERENCES

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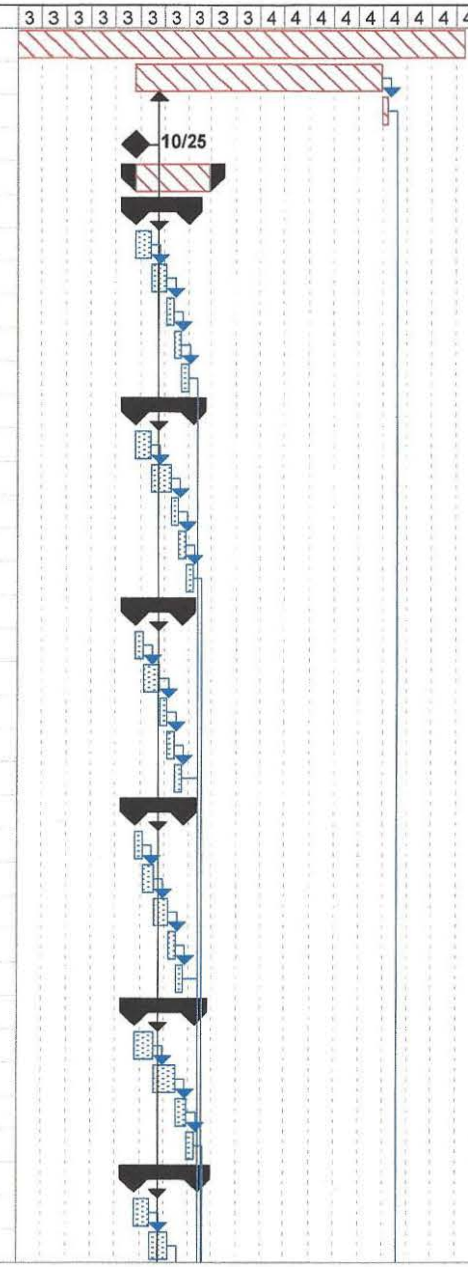
APPENDIX A

SCHEDULE

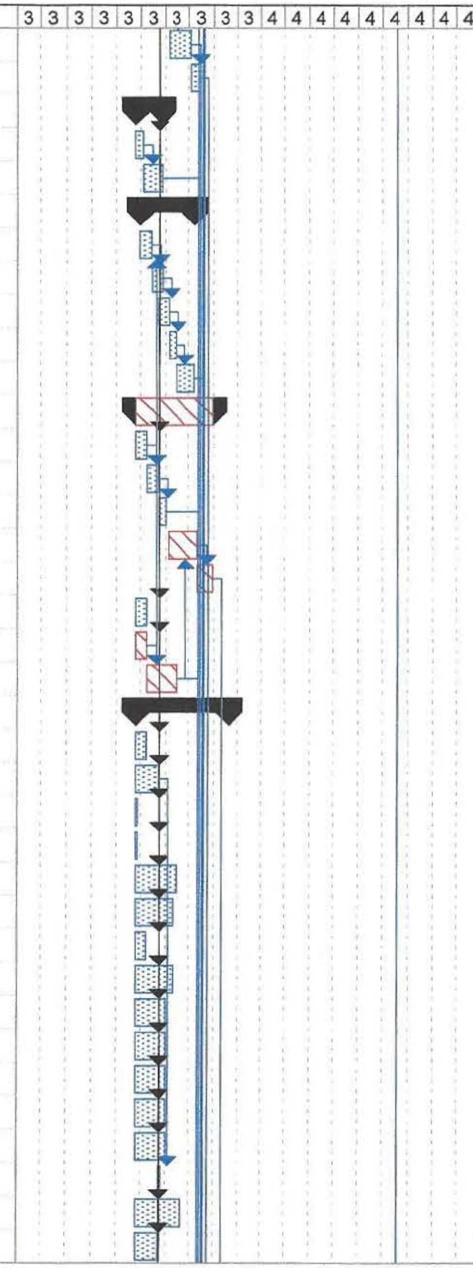
2015 D. C. Cook
Scenario 1

ID	Task Name	Duration	Start	Finish	Predecessors
1	Dry spent fuel storage	1925 wks	Fri 7/1/11	Thu 5/21/48	
2	Post-shutdown wet storage	531 wks	Wed 10/25/34	Tue 12/27/44	4
3	Transfer remaining assemblies to ISFSI	13 wks	Wed 12/28/44	Tue 3/28/45	2
4	Unit 1 Down	0 days	Wed 10/25/34	Wed 10/25/34	
5	**Period 1 Decommissioning Planning**	**825 days**	**Wed 10/25/34**	**Tue 12/22/37**	
6	**Modify spent fuel support systems**	**576 days**	**Wed 10/25/34**	**Wed 1/7/37**	
7	Define systems modification	168 days	Wed 10/25/34	Fri 6/15/35	4
8	Design systems modification and equipment specificatons	168 days	Mon 6/18/35	Wed 2/6/36	7
9	Prepare installation procedures	80 days	Thu 2/7/36	Wed 5/28/36	8
10	Prepare test procedures	80 days	Thu 5/29/36	Wed 9/17/36	9
11	Prepare maintenance procedures	80 days	Thu 9/18/36	Wed 1/7/37	10
12	**Control room relocation**	**624 days**	**Wed 10/25/34**	**Mon 3/16/37**	
13	Define control room equipment	168 days	Wed 10/25/34	Fri 6/15/35	4
14	Design control room modification and equipment specificatons	216 days	Mon 6/18/35	Mon 4/14/36	13
15	Prepare installation procedures	80 days	Tue 4/15/36	Mon 8/4/36	14
16	Prepare test procedures	80 days	Tue 8/5/36	Mon 11/24/36	15
17	Prepare maintenance procedures	80 days	Tue 11/25/36	Mon 3/16/37	16
18	**Design spent fuel storage security modifications**	**504 days**	**Wed 10/25/34**	**Mon 9/29/36**	
19	Define modification	88 days	Wed 10/25/34	Fri 2/23/35	4
20	Design modification and equipment specificatons	176 days	Mon 2/26/35	Mon 10/29/35	19
21	Prepare installation procedures	80 days	Tue 10/30/35	Mon 2/18/36	20
22	Prepare test procedures	80 days	Tue 2/19/36	Mon 6/9/36	21
23	Prepare maintenance procedures	80 days	Tue 6/10/36	Mon 9/29/36	22
24	**Primary system decontamination**	**520 days**	**Wed 10/25/34**	**Tue 10/21/36**	
25	Define scope	80 days	Wed 10/25/34	Tue 2/13/35	4
26	Evaluate processes	120 days	Wed 2/14/35	Tue 7/31/35	25
27	Prepare bid specifications and RFP	160 days	Wed 8/1/35	Tue 3/11/36	26
28	Qualify Contractors	80 days	Wed 3/12/36	Tue 7/1/36	27
29	Evaluate Proposals	80 days	Wed 7/2/36	Tue 10/21/36	28
30	**Select Decommissioning General Contractor**	**640 days**	**Wed 10/25/34**	**Tue 4/7/37**	
31	Define scope	200 days	Wed 10/25/34	Tue 7/31/35	4
32	Prepare bid specifications and RFP	240 days	Wed 8/1/35	Tue 7/1/36	31
33	Qualify Contractors	120 days	Wed 7/2/36	Tue 12/16/36	32
34	Evaluate Proposals	80 days	Wed 12/17/36	Tue 4/7/37	33
35	**U1 & U2 cold and dark site repowering**	**680 days**	**Wed 10/25/34**	**Tue 6/2/37**	
36	Define scope	160 days	Wed 10/25/34	Tue 6/5/35	4
37	Design modification and equipment specificatons	200 days	Wed 6/6/35	Tue 3/11/36	36



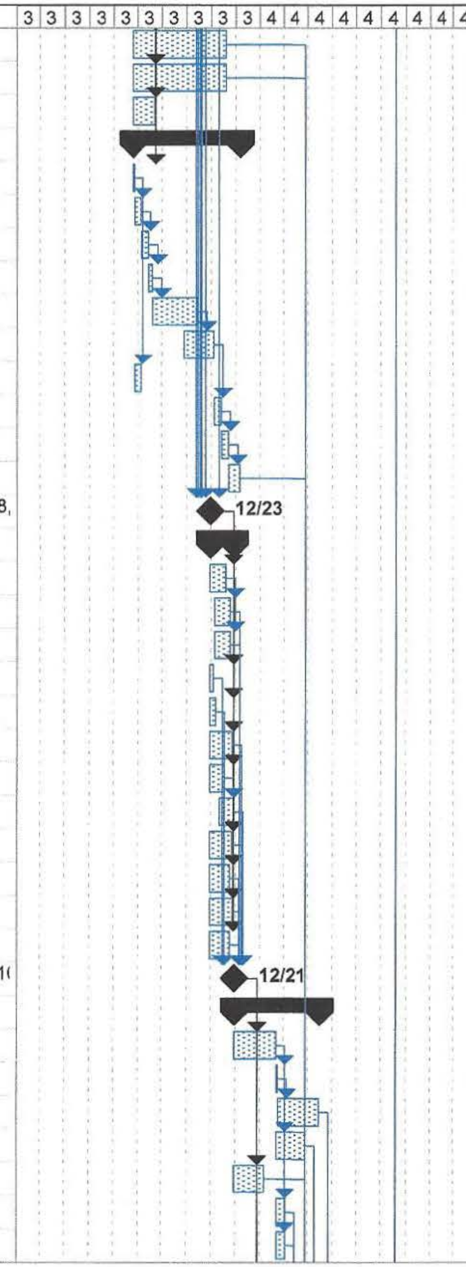
2015 D. C. Cook
Scenario 1

ID	Task Name	Duration	Start	Finish	Predecessors
38	Prepare installation procedures	240 days	Wed 3/12/36	Tue 2/10/37	37
39	Prepare test procedures	80 days	Wed 2/11/37	Tue 6/2/37	38
40	**Modify U1 & U2 containment access**	**280 days**	**Wed 10/25/34**	**Tue 11/20/35**	
41	Select new access location	80 days	Wed 10/25/34	Tue 2/13/35	4
42	Design access and equipment specificatons	200 days	Wed 2/14/35	Tue 11/20/35	41
43	**U1 & U2 Site Characterization**	**590 days**	**Wed 12/27/34**	**Tue 3/31/37**	
44	Define scope	120 days	Wed 12/27/34	Tue 6/12/35	56FS-75 days
45	Prepare bid specifications and RFP	120 days	Wed 6/13/35	Tue 11/27/35	44
46	Qualify Contractors	120 days	Wed 9/19/35	Tue 3/4/36	45FS-50 days
47	Evaluate Proposals	80 days	Wed 3/5/36	Tue 6/24/36	46
48	Prepare procedures	200 days	Wed 6/25/36	Tue 3/31/37	47
49	**ADMINISTRATIVE ACTIVITIES**	**825 days**	**Wed 10/25/34**	**Tue 12/22/37**	
50	Develop staff transition plan	120 days	Wed 10/25/34	Tue 4/10/35	4
51	Develop severance and retention policy	120 days	Wed 4/11/35	Tue 9/25/35	50
52	Prepare project administrative procedures	80 days	Wed 9/26/35	Tue 1/15/36	51
53	Develop area based decommissioning cost estimate	320 days	Wed 2/20/36	Tue 5/12/37	57FS-19 wks
54	Develop project budget and schedule controls	160 days	Wed 5/13/37	Tue 12/22/37	53
55	Assemble plant drawings	120 days	Wed 10/25/34	Tue 4/10/35	4
56	Define end product	120 days	Wed 10/25/34	Tue 4/10/35	4
57	Develop technical approach and detailed project plans	320 days	Wed 4/11/35	Tue 7/1/36	56
58	**LICENSING/PERMITTING DOCUMENTATION**	**1000 days**	**Wed 10/25/34**	**Tue 8/24/38**	
59	Insurance exemption	120 days	Wed 10/25/34	Tue 4/10/35	4
60	Prepare Post-Shutdown Decommissioning Activities Report	240 days	Wed 10/25/34	Tue 9/25/35	4
61	Prepare certification of permanent cessation of operations	24 days	Wed 10/25/34	Mon 11/27/34	4
62	Prepare certification of permanent reactor defueling	24 days	Wed 10/25/34	Mon 11/27/34	4
63	Prepare post-shutdown technical specification modifications	440 days	Wed 10/25/34	Tue 7/1/36	4
64	Update FSAR	400 days	Wed 10/25/34	Tue 5/6/36	4
65	Develop certified fuel handler program	120 days	Wed 10/25/34	Tue 4/10/35	4
66	Prepare post-shutdown emergency plan	400 days	Wed 10/25/34	Tue 5/6/36	4
67	Prepare post-shutdown QA plan	320 days	Wed 10/25/34	Tue 1/15/36	4
68	Prepare post-shutdown security plan	320 days	Wed 10/25/34	Tue 1/15/36	4
69	Prepare post-shutdown fire protection plan	320 days	Wed 10/25/34	Tue 1/15/36	4
70	Prepare post-shutdown radiation protection manual	320 days	Wed 10/25/34	Tue 1/15/36	4
71	Prepare and submit state and local permits	320 days	Wed 10/25/34	Tue 1/15/36	4
72	Respond to NRC questions on PSDAR	24 days	Wed 9/26/35	Mon 10/29/35	60
73	Prepare detailed resource loaded project schedule	480 days	Wed 10/25/34	Tue 8/26/36	4
74	Perform 50.59 unreviewed safety questions	240 days	Wed 10/25/34	Tue 9/25/35	4



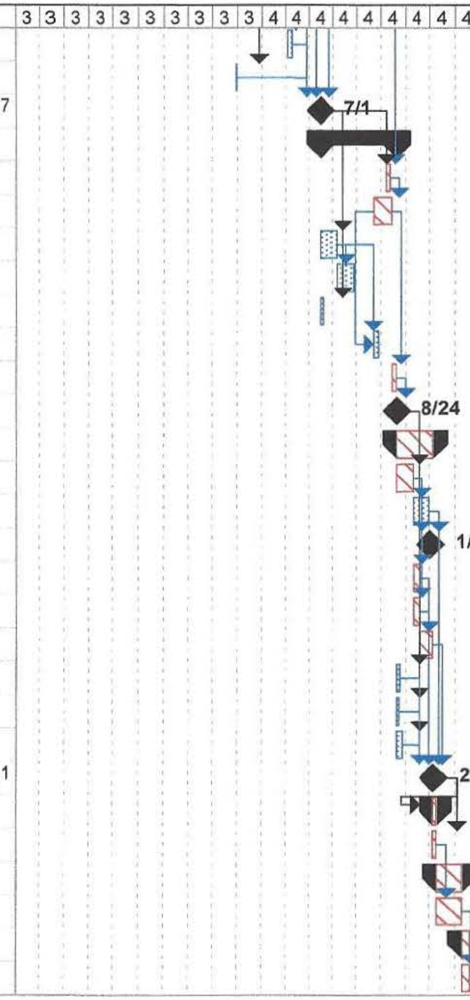
2015 D. C. Cook
Scenario 1

ID	Task Name	Duration	Start	Finish	Predecessors
75	Prepare activity specifications	1000 days	Wed 10/25/34	Tue 8/24/38	4
76	Prepare detailed work procedures	1000 days	Wed 10/25/34	Tue 8/24/38	4
77	Select shipping casks and obtain permits	240 days	Wed 10/25/34	Tue 9/25/35	4
78	**LICENSE TERMINATION PLAN**	**1144 days**	**Wed 10/25/34**	**Mon 3/14/39**	
79	General information	16 days	Wed 10/25/34	Wed 11/15/34	4
80	Site Characterization	80 days	Thu 11/16/34	Wed 3/7/35	79
81	Identification of remaining site dismantlement activities	80 days	Thu 3/8/35	Wed 6/27/35	80
82	Remediation Plans	40 days	Thu 6/28/35	Wed 8/22/35	81
83	Final Radiation Survey Plan	480 days	Thu 8/23/35	Wed 6/24/37	82
84	Compliance with the radiological criteria for license termination	320 days	Thu 11/27/36	Wed 2/17/38	83FS-150 days
85	Update decommissioning cost estimate	80 days	Thu 11/16/34	Wed 3/7/35	79
86	Supplement to the environmental report	80 days	Thu 2/18/38	Wed 6/9/38	84
87	Respond to NRC questions	80 days	Thu 6/10/38	Wed 9/29/38	86
88	Update LTP	118 days	Thu 9/30/38	Mon 3/14/39	87
89	Unit 2 Down	0 days	Wed 12/23/37	Wed 12/23/37	11,17,23,29,34,38,
90	**Period 2 Post-Shutdown Activities**	**260 days**	**Wed 12/23/37**	**Tue 12/21/38**	
91	Modify Spent Fuel Cooling System	173 days	Wed 12/23/37	Fri 8/20/38	89
92	Modify control room	173 days	Mon 3/1/38	Wed 10/27/38	91FS-125 days
93	Modify security system	173 days	Mon 3/1/38	Wed 10/27/38	91FS-125 days
94	Primary System Decon	40 days	Wed 12/23/37	Tue 2/16/38	89
95	Flush & Drain Systems	60 days	Wed 12/23/37	Tue 3/16/38	89
96	Implement cold & dark	240 days	Wed 12/23/37	Tue 11/23/38	89
97	Modify U1 Containment Access	160 days	Wed 12/23/37	Tue 8/3/38	89
98	Modify U2 Containment Access	160 days	Wed 5/12/38	Tue 12/21/38	97FS-60 days
99	Historical Site Assessment	240 days	Wed 12/23/37	Tue 11/23/38	89
100	Vessel and internals activation analysis	215 days	Wed 12/23/37	Tue 10/19/38	89
101	Characterization survey	250 days	Wed 12/23/37	Tue 12/7/38	89
102	Test special equipment and training	215 days	Wed 12/23/37	Tue 10/19/38	89
103	End Period 2	0 days	Tue 12/21/38	Tue 12/21/38	94,95,96,99,100,1(
104	**Period 3 Reactor Vessel and Internals Removal**	**920 days**	**Wed 12/22/38**	**Tue 7/1/42**	
105	Remove Unit 1 reactor vessel internals and reactor vessel	450 days	Wed 12/22/38	Tue 9/11/40	103
106	Transfer Equipment to Unit 2	4 wks	Wed 9/12/40	Tue 10/9/40	105
107	Remove Unit 2 reactor vessel internals and reactor vessel	450 days	Wed 10/10/40	Tue 7/1/42	106
108	Remove Unit 1 steam generators	65 wks	Wed 9/12/40	Tue 12/10/41	105
109	Remove Unit 2 steam generators	65 wks	Wed 12/22/38	Tue 3/20/40	103
110	Remove Unit 1 contaminated systems	105 days	Wed 9/12/40	Tue 2/5/41	105
111	Remove Unit 1 clean systems	103 days	Wed 9/12/40	Fri 2/1/41	105



2015 D. C. Cook
Scenario 1

ID	Task Name	Duration	Start	Finish	Predecessors
112	Decon Unit 1 reactor building	56 days	Wed 2/6/41	Wed 4/24/41	110,111
113	Remove miscellaneous structures	8 days	Wed 12/22/38	Fri 12/31/38	103
114	End Period 3	0 days	Tue 7/1/42	Tue 7/1/42	108,109,112,113,7
115	**Period 4 Building Decontamination**	**822 days**	**Wed 7/2/42**	**Thu 8/24/45**	
116	Remove Spent fuel storage racks	8 wks	Wed 3/29/45	Tue 5/23/45	114,3
117	Remove Unit 2 contaminated systems	194 days	Thu 9/22/44	Tue 6/20/45	116FS-174 days
118	Remove Unit 2 clean systems	190 days	Wed 7/2/42	Tue 3/24/43	114
119	Remove Turbine Building	188 days	Wed 3/25/43	Fri 12/11/43	118
120	Decon Steam Generator Storage Building	35 days	Wed 7/2/42	Tue 8/19/42	114
121	Decon Unit 2 Reactor Building	56 days	Thu 9/22/44	Thu 12/8/44	117SS,118
122	Decon Auxiliary Building	47 days	Wed 6/21/45	Thu 8/24/45	117
123	End Period 4	0 days	Thu 8/24/45	Thu 8/24/45	122
124	**Period 5 Clean Removal**	**392 days**	**Fri 8/25/45**	**Mon 2/25/47**	
125	Perform final radiological survey of all structures	36 wks	Fri 8/25/45	Thu 5/3/46	123
126	Perform final survey of the site	36 wks	Fri 5/4/46	Thu 1/10/47	125
127	Obtain NRC approval	0 days	Thu 1/10/47	Thu 1/10/47	126,125
128	Remove Unit 1 reactor building	80 days	Fri 5/4/46	Thu 8/23/46	125
129	Remove Unit 2 reactor building	80 days	Fri 5/4/46	Thu 8/23/46	125
130	Remove Auxiliary Building	132 days	Fri 8/24/46	Mon 2/25/47	129,128
131	Remove Steam Generator Storage Building	40 days	Fri 8/25/45	Thu 10/19/45	123
132	Remove Administration building	31 days	Fri 8/25/45	Fri 10/6/45	123
133	Remove Low Level Radwaste building	66 days	Fri 8/25/45	Fri 11/24/45	123
134	End Period 5	0 days	Mon 2/25/47	Mon 2/25/47	129,131,132,133,1
135	**Period 6 Restore site**	**40 days**	**Tue 2/26/47**	**Mon 4/22/47**	**134**
136	Restore site	8 wks	Tue 2/26/47	Mon 4/22/47	134
137	**Period 7 Dry Storage**	**260 days**	**Tue 4/23/47**	**Mon 4/20/48**	
138	Dry Storage	52 wks	Tue 4/23/47	Mon 4/20/48	136
139	**Period 8 ISFSI Removal**	**84 days**	**Tue 4/21/48**	**Fri 8/14/48**	
140	Decon and remove ISFSI	16.8 wks	Tue 4/21/48	Fri 8/14/48	138



APPENDIX B

COST TABLE

2015 D. C. Cook
Scenario 1
DECON and Permanent On-Site Dry Storage

	Type		Staff Labor, $	Craft Labor, $	Equipment & Materials, $	Packaging, $	Transportation, $	Clean Disposal, $	Contaminated Disposal, $	Energy, $	Other, $	Subtotal without Contingency, $	Contingency, $	Total with Contingency, $	Staff Manhours	Clean Craft Manhours	Contaminated Craft Manhours
PERIOD 1 - U1 & U2 DECOMMISSIONING PLANNING COST:																	
		SPENT FUEL ACTIVITIES															
		Modify spent fuel support systems															
1	A 50.54(bb)	Define systems modification	$65,204									$65,204	$9,800	$75,004	608		
1	A 50.54(bb)	Design systems modification and equipment specificatons	$155,196									$155,196	$23,300	$178,496	1,568		
1	A 50.54(bb)	Prepare installation procedures	$19,042									$19,042	$2,900	$21,942	192		
1	A 50.54(bb)	Prepare test procedures	$19,042									$19,042	$2,900	$21,942	192		
1	A 50.54(bb)	Prepare maintenance procedures	$19,042									$19,042	$2,900	$21,942	192		
		Control room relocation															
1	A 50.54(bb)	Define control room equipment	$65,204									$65,204	$9,800	$75,004	608		
1	A 50.54(bb)	Design control room modification and equipment specificatons	$188,091									$188,091	$28,200	$216,291	1,896		
1	A 50.54(bb)	Prepare installation procedures	$19,042									$19,042	$2,900	$21,942	192		
1	A 50.54(bb)	Prepare test procedures	$19,042									$19,042	$2,900	$21,942	192		
1	A 50.54(bb)	Prepare maintenance procedures	$19,042									$19,042	$2,900	$21,942	192		
		Design spent fuel storage security modifications															
1	A 50.54(bb)	Define modification	$30,754									$30,754	$4,600	$35,354	288		
1	A 50.54(bb)	Design modification and equipment specificatons	$107,927									$107,927	$16,200	$124,127	1,016		
1	A 50.54(bb)	Prepare installation procedures	$19,042									$19,042	$2,900	$21,942	192		
1	A 50.54(bb)	Prepare test procedures	$19,042									$19,042	$2,900	$21,942	192		
1	A 50.54(bb)	Prepare maintenance procedures	$19,042									$19,042	$2,900	$21,942	192		
1	A 50.54(bb)	ISFSI Pad Construction		$135,000,000								$135,000,000	$32,181,700	$167,181,700	192		
		SUBTOTAL - SPENT FUEL ACTIVITIES	$783,758	$135,000,000								$135,783,758	$32,299,700	$168,083,458	7,904		
		SPENT FUEL PERIOD DEPENDENT															
1	PD 50.54(bb)	Utility Staff															
1	PD 50.54(bb)	Security															
1	PD 50.54(bb)	Insurance									$2,882,843	$2,882,843	$432,400	$3,315,243			
1	PD 50.54(bb)	O & M Budget Items															
1	PD 50.54(bb)	Permits & Fees															
1	PD 50.54(bb)	Waste Transfer and Loading															
1	PD 50.54(bb)	Energy															
1	PD 50.54(bb)	Spent Fuel Storage Maintenance Supplies															
1	PD 50.54(bb)	Small Tools			$1,350,000							$1,350,000	$337,500	$1,687,500			
		SUBTOTAL - SPENT FUEL PERIOD DEPENDENT			$1,350,000						$2,882,843	$4,232,843	$769,900	$5,002,743			
		DECOMMISSIONING ACTIVITIES															
		Primary system decontamination															
1	A 50.75(c)	Define scope	$43,826									$43,826	$6,600	$50,426	328		
1	A 50.75(c)	Evaluate processes	$55,757									$55,757	$8,400	$64,157	448		
1	A 50.75(c)	Prepare bid specifications and RFP	$55,713									$55,713	$8,400	$84,113	512		
1	A 50.75(c)	Qualify Contractors	$15,010									$15,010	$2,300	$17,310	112		
1	A 50.75(c)	Evaluate Proposals	$41,198									$41,198	$6,200	$47,398	248		
		Select Decommissioning General Contractor															
1	A 50.75(c)	Define scope	$83,634									$83,634	$12,500	$96,134	736		
1	A 50.75(c)	Prepare bid specifications and RFP	$88,549									$88,549	$13,300	$101,849	776		
1	A 50.75(c)	Qualify Contractors	$23,013									$23,013	$3,500	$26,513	176		
1	A 50.75(c)	Evaluate Proposals	$41,198									$41,198	$6,200	$47,398	248		
		U1 & U2 cold and dark site repowering															
1	A 50.75(c)	Define scope	$71,703									$71,703	$10,800	$82,503	616		
1	A 50.75(c)	Design modification and equipment specificatons	$158,617									$158,617	$23,800	$182,417	1,560		
1	A 50.75(c)	Prepare installation procedures	$222,607									$222,607	$33,400	$256,007	2,080		
1	A 50.75(c)	Prepare test procedures	$19,042									$19,042	$2,900	$21,942	192		
		Modify U1 & U2 containment access															
1	A 50.75(c)	Select new access location	$31,895									$31,895	$4,800	$36,695	208		
1	A 50.75(c)	Design access and equipment specificatons	$140,511									$140,511	$21,100	$161,611	1,320		
		U1 & U2 Site Characterization															
1	A 50.75(c)	Define scope	$50,169									$50,169	$7,500	$57,669	408		
1	A 50.75(c)	Prepare bid specifications and RFP	$56,812									$56,812	$8,500	$65,312	496		
1	A 50.75(c)	Qualify Contractors	$23,013									$23,013	$3,500	$26,513	176		
1	A 50.75(c)	Evaluate Proposals	$41,198									$41,198	$6,200	$47,398	248		
1	A 50.75(c)	Prepare procedures	$139,929									$139,929	$21,000	$160,929	1,256		
		ADMINISTRATIVE ACTIVITIES															
1	A 50.75(c)	Develop staff transition plan	$43,226									$43,226	$6,500	$49,726	352		
1	A 50.75(c)	Develop severance and retention policy	$43,226									$43,226	$6,500	$49,726	352		
1	A 50.75(c)	Prepare project administrative procedures	$46,957									$46,957	$7,000	$53,957	488		
1	A 50.75(c)	Develop area based decommissioning cost estimate	$217,919									$217,919	$32,700	$250,619	2,240		
1	A 50.75(c)	Develop project budget and schedule controls	$63,304									$63,304	$9,500	$72,804	648		
1	A 50.75(c)	Assemble plant drawings	$25,276									$25,276	$3,800	$29,076	296		
1	A 50.75(c)	Define end product	$38,096									$38,096	$5,700	$43,796	280		
1	A 50.75(c)	Develop technical approach and detailed project plans	$234,546									$234,546	$35,200	$269,746	2,440		

2015 D. C. Cook
Scenario 1
DECON and Permanent On-Site Dry Storage

	Type		Staff Labor,$	Craft Labor,$	Equipment & Materials, $	Packaging, $	Transportation, $	Clean Disposal, $	Contaminated Disposal, $	Energy, $	Other, $	without Contingency, $	Contingency, $	with Contingency, $	Staff Manhours	Craft Manhours	Craft Manhours
		LICENSING/PERMITTING DOCUMENTATION															
1	A 50.75(c)	Insurance exemption	$48,428									$48,428	$7,300	$55,728	376		
1	A 50.75(c)	Prepare Post-Shutdown Decommissioning Activities Report	$140,561									$140,561	$21,100	$161,661	1,400		
1	A 50.75(c)	Prepare certification of permanent cessation of operations	$6,394									$6,394	$1,000	$7,394	40		
1	A 50.75(c)	Prepare certification of permanent reactor defueling	$6,394									$6,394	$1,000	$7,394	40		
1	A 50.75(c)	Prepare post-shutdown technical specification modifications	$347,695									$347,695	$52,200	$399,895	3,600		
1	A 50.75(c)	Update FSAR	$322,717									$322,717	$48,400	$371,117	3,360		
1	A 50.75(c)	Develop certified fuel handler program	$37,648									$37,648	$5,600	$43,248	336		
1	A 50.75(c)	Prepare post-shutdown emergency plan	$169,694									$169,694	$25,500	$195,194	1,480		
1	A 50.75(c)	Prepare post-shutdown QA plan	$108,471									$108,471	$16,300	$124,771	1,000		
1	A 50.75(c)	Prepare post-shutdown security plan	$108,471									$108,471	$16,300	$124,771	1,000		
1	A 50.75(c)	Prepare post-shutdown fire protection plan	$108,471									$108,471	$16,300	$124,771	1,000		
1	A 50.75(c)	Prepare post-shutdown radiation protection manual	$108,471									$108,471	$16,300	$124,771	1,000		
1	A 50.75(c)	Prepare and submit state and local permits	$98,477									$98,477	$14,800	$113,277	960		
1	A 50.75(c)	Respond to NRC questions on PSDAR	$6,394									$6,394	$1,000	$7,394	40		
1	A 50.75(c)	Prepare detailed resource loaded project schedule	$267,312									$267,312	$40,100	$307,412	2,480		
1	A 50.75(c)	Perform 50.59 unreviewed safety questions	$97,771									$97,771	$14,700	$112,471	738		
1	A 50.75(c)	Prepare activity specifications	$1,807,127									$1,807,127	$271,100	$2,078,227	18,080		
1	A 50.75(c)	Prepare detailed work procedures	$1,667,732									$1,667,732	$250,200	$1,917,932	16,080		
1	A 50.75(c)	Select shipping casks and obtain permits	$25,243									$25,243	$3,800	$29,043	240		
		LICENSE TERMINATION PLAN															
1	A 50.75(c)	General information	$1,407									$1,407	$200	$1,607	16		
1	A 50.75(c)	Site Characterization	$35,465									$35,465	$5,300	$40,765	336		
1	A 50.75(c)	Identification of remaining site dismantlement activities	$35,465									$35,465	$5,300	$40,765	336		
1	A 50.75(c)	Remediation Plans	$18,631									$18,631	$2,800	$21,431	176		
1	A 50.75(c)	Final Radiation Survey Plan	$353,367									$353,367	$53,000	$406,367	3,620		
1	A 50.75(c)	Compliance with the radiological criteria for license termination	$237,240									$237,240	$35,600	$272,840	2,440		
1	A 50.75(c)	Update decommissioning cost estimate	$57,848									$57,848	$8,700	$66,548	596		
1	A 50.75(c)	Supplement to the environmental report	$57,848									$57,848	$8,700	$66,548	596		
1	A 50.75(c)	Respond to NRC questions	$27,395									$27,395	$4,100	$31,495	200		
1	A 50.75(c)	Update LTP	$53,329									$53,329	$8,000	$61,329	536		
		SUBTOTAL - DECOMMISSIONING ACTIVITY COSTS:	$8,477,411									$8,477,411	$1,272,500	$9,749,911	81,340		
		DECOMMISSIONING PERIOD DEPENDENT															
1	PD 50.75(c)	Utility Staff	$3,974,726									$3,974,726	$596,200	$4,570,926	75,575		
1	PD 50.75(c)	DGC Staff	$4,633,240									$4,633,240	$695,000	$5,328,240	56,159		
1	PD 50.75(c)	Security	$755,209									$755,209	$113,300	$868,509	29,573		
1	PD 50.75(c)	HP Supplies			$276,718							$276,718	$69,200	$345,918			
1	PD 50.75(c)	Equipment			$301,422							$301,422	$75,400	$376,822			
1	PD 50.75(c)	Unit 1 Insurance									$1,223,073	$1,223,073	$183,500	$1,406,573			
1	PD 50.75(c)	Unit 2 Insurance															
1	PD 50.75(c)	O & M Budget Items			$156,229							$156,229	$39,100	$195,329			
1	PD 50.75(c)	Permits & Fees									$1,995,919	$1,995,919	$299,400	$2,295,319			
1	PD 50.75(c)	Waste Transfer and Loading															
1	PD 50.75(c)	Energy								$3,482,181		$3,482,181	$522,300	$4,004,481			
1	PD 50.75(c)	Severance	$18,173,408									$18,173,408	$2,726,000	$20,899,408			
1	PD 50.75(c)	Small Tools															
		SUBTOTAL - DECOMMISSIONING PERIOD DEPENDENT	$27,536,583		$734,369					$3,482,181	$3,218,992	$34,972,125	$5,319,400	$40,291,525	161,307		
		TOTAL PERIOD 1 - U1 & U2 DECOMMISSIONING PLANNING COST:	$36,797,752	$135,000,000	$2,084,369					$3,482,181	$6,101,835	$183,466,137	$39,661,500	$223,127,637	250,552		
		ACTIVITY															
		UNIT 1 - PERIOD 1 COSTS															
		Unit 1 Subtotal 10 CFR 50.75(c):															
		Unit 1 Subtotal 10 CFR 50.54(bb):															
		UNIT 2															
		Unit 2 Subtotal 10 CFR 50.75(c):															
		Unit 2 Subtotal 10 CFR 50.54(bb):															
		Common															
		Total 10 CFR 50.75(c):	$8,477,411									$8,477,411	$1,272,500	$9,749,911	81,340		
		Total 10 CFR 50.54(bb):	$783,758	$135,000,000								$135,783,758	$32,299,700	$168,083,458	7,904		
		PERIOD DEPENDENT															
		UNIT 1 - PERIOD 1 COSTS															
		Unit 1 Subtotal 10 CFR 50.75(c):	$27,536,583		$734,369					$3,482,181	$3,218,992	$34,972,125	$5,319,400	$40,291,525	161,307		
		Unit 1 Subtotal 10 CFR 50.54(bb):															
		UNIT 2															
		Unit 2 Subtotal 10 CFR 50.75(c):															
		Unit 2 Subtotal 10 CFR 50.54(bb):															
		Common															

Type			Staff Labor, $	Craft Labor, $	Equipment & Materials, $	Packaging, $	Transportation, $	Clean Disposal, $	Contaminated Disposal, $	Energy, $	Other, $	without Contingency, $	Contingency, $	with Contingency, $	Staff Manhours	Craft Manhours	Craft Manhours
		Total 10 CFR 50.75(c):															
		Total 10 CFR 50.54(bb):			$1,350,000						$2,882,843	$4,232,843	$769,900	$5,002,743			
		Unit 1, Unit 2 & Common															
		Total 10 CFR 50.75(c):	$36,013,994		$734,369					$3,482,181	$3,218,992	$43,449,536	$6,591,900	$50,041,436	242,649		
		Total 10 CFR 50.54(bb):	$783,758	$135,000,000	$1,350,000						$2,882,843	$140,016,601	$33,069,600	$173,086,201	7,904		
PERIOD 2 - POST-SHUTDOWN ACTIVITIES COSTS:																	
		SPENT FUEL ACTIVITIES															
2	A 50.54(bb)	Modify Spent Fuel Cooling System		$640,667	$1,165,000							$1,805,667	$444,000	$2,249,667		9,360	
2	A 50.54(bb)	Modify control room		$588,869	$800,000							$1,388,869	$340,400	$1,729,269		9,360	
2	A 50.54(bb)	Modify security system		$459,341	$525,000							$984,341	$240,700	$1,225,041		7,280	
2	A 50.54(bb)	Puchase ISFSI casks			$111,000,000							$111,000,000	$27,750,000	$138,750,000		7,280	
		SUBTOTAL - SPENT FUEL ACTIVITIES		$1,688,877	$113,490,000							$115,178,877	$28,775,100	$143,953,977		33,280	
		SPENT FUEL PERIOD DEPENDENT															
2	PD 50.54(bb)	Utility Staff	$3,363,648									$3,363,648	$504,500	$3,868,148	68,406		
2	PD 50.54(bb)	Security	$1,295,527									$1,295,527	$194,300	$1,489,827	49,750		
2	PD 50.54(bb)	Insurance									$1,619,318	$1,619,318	$242,900	$1,862,218			
2	PD 50.54(bb)	O & M Budget Items															
2	PD 50.54(bb)	Permits & Fees									$1,007,525	$1,007,525	$151,100	$1,158,625			
2	PD 50.54(bb)	Waste Transfer and Loading															
2	PD 50.54(bb)	Energy								$848,474		$848,474	$127,300	$975,774			
2	PD 50.54(bb)	Spent Fuel Storage Maintenance Supplies															
2	PD 50.54(bb)	Small Tools			$16,889							$16,889	$4,200	$21,089			
		SUBTOTAL - SPENT FUEL PERIOD DEPENDENT	$4,659,176		$16,889					$848,474	$2,626,843	$8,151,382	$1,224,300	$9,375,682	118,155		
		DECOMMISSIONING ACTIVITIES															
2	A 50.75(c)	Primary System Decon Unit 1 & 2		$8,902,125	$1,476,125				$9,340,250			$19,718,500	$6,008,600	$25,727,100			
2	A 50.75(c)	Flush & Drain Systems (PERFORMED BY UTILITY STAFF)															
2	A 50.75(c)	Implement cold & dark		$773,783	$1,600,000							$2,373,783	$584,500	$2,958,283		11,520	
2	A 50.75(c)	Modify U1 Containment Access		$351,391	$525,000							$876,391	$215,000	$1,091,391		5,760	
2	A 50.75(c)	ModifyU2 Containment Access		$351,391	$525,000							$876,391	$215,000	$1,091,391		5,760	
2	A 50.75(c)	Historical Site Assessment	$331,734									$331,734	$49,800	$381,534	4,880		
2	A 50.75(c)	Vessel and internals activation analysis	$116,901									$116,901	$17,500	$134,401	640		
2	A 50.75(c)	Characterization survey	$754,270									$754,270	$113,100	$867,370	12,880		
2	A 50.75(c)	Test special equipment and training		$947,439								$947,439	$225,900	$1,173,339		13,440	
		SUBTOTAL - DECOMMISSIONING ACTIVITY COSTS:	$1,202,906	$11,326,129	$4,126,125				$9,340,250			$25,995,410	$7,429,400	$33,424,810	18,400	36,480	
		DECOMMISSIONING PERIOD DEPENDENT															
2	PD 50.75(c)	Utility Staff	$15,093,537									$15,093,537	$2,264,000	$17,357,537	300,570		
2	PD 50.75(c)	DGC Staff	$11,310,434									$11,310,434	$1,696,600	$13,007,034	157,540		
2	PD 50.75(c)	Security	$3,674,302									$3,674,302	$551,100	$4,225,402	149,249		
2	PD 50.75(c)	HP Supplies			$929,326							$929,326	$232,300	$1,161,626			
2	PD 50.75(c)	Equipment			$1,286,080							$1,286,080	$321,500	$1,607,580			
2	PD 50.75(c)	Unit 1 Insurance									$385,787	$385,787	$57,900	$443,687			
2	PD 50.75(c)	Unit 2 Insurance									$385,787	$385,787	$57,900	$443,687			
2	PD 50.75(c)	O & M Budget Items			$11,459,323							$11,459,323	$2,864,800	$14,324,123			
2	PD 50.75(c)	Permits & Fees									$2,440,340	$2,440,340	$366,100	$2,806,440			
2	PD 50.75(c)	Waste Transfer and Loading															
2	PD 50.75(c)	Energy								$4,201,784		$4,201,784	$630,300	$4,832,084			
2	PD 50.75(c)	Severance	$28,209,801									$28,209,801	$4,231,500	$32,441,301			
2	PD 50.75(c)	Small Tools			$226,523							$226,523	$56,600	$283,123			
		SUBTOTAL - DECOMMISSIONING PERIOD DEPENDENT	$58,288,075		$13,901,251					$4,201,784	$3,211,915	$79,603,024	$13,330,600	$92,933,624	607,359		
		TOTAL PERIOD 2 - POST-SHUTDOWN ACTIVITIES COSTS:	$64,150,156	$13,015,006	$131,534,264				$9,340,250	$5,050,259	$5,838,757	$228,928,693	$50,759,400	$279,688,093	743,914	69,760	
		ACTIVITY															
		UNIT 1															
		Unit 1 Subtotal 10 CFR 50.75(c):		$4,802,454	$1,263,063				$4,670,125			$10,735,641	$3,219,300	$13,954,941		5,760	
		Unit 1 Subtotal 10 CFR 50.54(bb):															
		UNIT 2															
		Unit 2 Subtotal 10 CFR 50.75(c):		$4,802,454	$1,263,063				$4,670,125			$10,735,641	$3,219,300	$13,954,941		5,760	
		Unit 2 Subtotal 10 CFR 50.54(bb):															
		Common															
		Common Subtotal - 10 CFR 50.75(c):	$1,202,906	$1,721,222	$1,600,000							$4,524,127	$990,800	$5,514,927	18,400	24,960	
		Common Subtotal - 10 CFR 50.54(bb):		$1,688,877	$113,490,000							$115,178,877	$28,775,100	$143,953,977		33,280	

2015 D. C. Cook
Scenario 1
DECON and Permanent On-Site Dry Storage

	Type		Staff Labor, $	Craft Labor, $	Equipment & Materials, $	Packaging, $	Transportation, $	Clean Disposal, $	Contaminated Disposal, $	Energy, $	Other, $	without Contingency, $	Contingency, $	with Contingency, $	Staff Manhours	Craft Manhours	Craft Manhours	
		PERIOD DEPENDENT																
		UNIT 1																
		Unit 1 Subtotal 10 CFR 50.75(c):																
		Unit 1 Subtotal 10 CFR 50.54(bb):																
		UNIT 2																
		Unit 2 Subtotal 10 CFR 50.75(c):																
		Unit 2 Subtotal 10 CFR 50.54(bb):																
		Common																
		Common Subtotal - 10 CFR 50.75(c):	$58,288,075		$13,901,251					$4,201,784	$3,211,915	$79,603,024	$13,330,600	$92,933,624	607,359			
		Common Subtotal - 10 CFR 50.54(bb):	$4,659,176		$16,889					$848,474	$2,626,843	$8,151,382	$1,224,300	$9,375,682	118,155			
		Unit 1, Unit 2 & Common																
		Total 10 CFR 50.75(c):	$59,490,981	$11,326,129	$18,027,376				$9,340,250	$4,201,784	$3,211,915	$105,598,434	$20,760,000	$126,358,434	625,759	36,480		
		Total 10 CFR 50.54(bb):	$4,659,176	$1,688,877	$113,506,889					$848,474	$2,626,843	$123,330,259	$29,999,400	$153,329,659	118,155	33,280		
PERIOD 3 VESSEL AND INTERNALS REMOVAL COSTS:																		
		SPENT FUEL ACTIVITIES																
3	A 50.54(bb)	Purcahse ISFSI Casks			$111,000,000							$111,000,000	$27,750,000	$138,750,000				
		SUBTOTAL - SPENT FUEL ACTIVITIES			$111,000,000							$111,000,000	$27,750,000	$138,750,000				
		SPENT FUEL PERIOD DEPENDENT																
3	PD 50.54(bb)	Utility Staff	$11,892,900									$11,892,900	$1,783,900	$13,676,800	241,863			
3	PD 50.54(bb)	Security	$3,644,479									$3,644,479	$546,700	$4,191,179	234,534			
3	PD 50.54(bb)	Insurance									$5,725,446	$5,725,446	$858,800	$6,584,246				
3	PD 50.54(bb)	O & M Budget Items																
3	PD 50.54(bb)	Permits & Fees									$3,562,320	$3,562,320	$534,300	$4,096,620				
3	PD 50.54(bb)	Waste Transfer and Loading																
3	PD 50.54(bb)	Energy								$1,939,299		$1,939,299	$290,900	$2,230,199				
3	PD 50.54(bb)	Spent Fuel Storage Maintenance Supplies																
3	PD 50.54(bb)	Small Tools																
		SUBTOTAL - SPENT FUEL PERIOD DEPENDENT	$15,537,379							$1,939,299	$9,287,766	$26,764,444	$4,014,600	$30,779,044	476,396			
		DECOMMISSIONING ACTIVITIES																
		UNIT 1																
3	A 50.75(c)	Install all reactor operating floor contamination control envelopes (CCEs), support structures, rigging, internals work platforms and process equipment (BY UTILITY STAFF)																Utility Staff
3	A 50.75(c)	Finalize Residual Radiation Inventory (WITH SITE CHARACTERIZATION)																
3	A 50.75(c)	Finalize Internals and Vessel Segmenting Details (WITH ACTIVATION ANALYSIS)																
3	A 50.75(c)	Remove, pack, ship and bury Unit 1 Pressurizer		$1,064,197		$800	$71,768		$933,410			$2,070,176	$621,000	$2,691,176			19,407	
3	A 50.75(c)	Decon, remove, package, ship and bury Unit 1 steam generators		$4,340,246	$1,532,267	$12,800	$823,395		$12,599,366			$19,308,074	$6,344,800	$25,652,874			79,163	
3	A 50.75(c)	Remove Unit 1 equipment hatch closure (BY UTILITY STAFF)																Utility Staff
3	A 50.75(c)	Remove Unit 1 control rod drive and reactor cavity missile shieldS (BY UTILITY STAFF)																Utility Staff
3	A 50.75(c)	Remove Unit 1 CRD mechanisms and cables, air ducts, and reactor vessel head (BY UTILI																Utility Staff
3	A 50.75(c)	Remove, segment, package and bury Unit 1 vessel & vessel head insulation		$182,000					$364,625			$546,625	$180,700	$727,325				
3	A 50.75(c)	Prepare Unit 1 vessel head for shipment as its own container (WITH VESSEL REMOVAL)																
3	A 50.75(c)	Decontaminate and clean up Unit 1 plant areas (BY UTILITY STAFF)																Utility Staff
3	A 50.75(c)	Process liquid and solid radioactive wastes (BY UTILITY STAFF)																Utility Staff
3	A 50.75(c)	Decon, remove, package, ship and dispose of Unit 1 contaminated systems		$13,812,807	$1,164,896	$91,337	$600,074		$5,142,875			$20,811,988	$5,663,600	$26,475,588			270,642	
3	A Greenfield	Remove, package, ship and dispose of Unit 1 clean systems		$14,574,156	$1,244,671		$182,236	$1,043,488				$17,044,553	$3,929,700	$20,974,253		284,077		
3	A 50.75(c)	Install Unit 1 water cleanup system in fuel transfer canal (BY UTILITY STAFF)																Vessel Removal
3	A 50.75(c)	Segment, package and ship Unit 1 internals as radioactive waste		$2,605,135	$526,565	$90,000	$5,022,524		$38,003,376			$46,247,599	$16,177,800	$62,425,399			47,360	
3	A 50.75(c)	Decontaminate internals work platform and store (BY UTILITY STAFF)																Vessel Removal
3	A 50.75(c)	Install Unit 1 vessel support structure (WITH VESSEL REMOVAL)																Vessel Removal
3	A 50.75(c)	Segment and process Unit 1 reactor vessel and associated equipment as LLW		$2,701,810	$148,187	$24,000	$2,339,070		$14,901,905			$20,114,971	$6,809,400	$26,924,371			49,100	
3	A 50.75(c)	Decontaminate reactor vessel platform and store																Vessel Removal
3	A 50.75(c)	Decontaminate Unit 1 reactor building		$2,529,030	$513,798	$294,710	$1,795,462		$9,297,096			$14,430,095	$4,662,600	$19,092,695			43,847	
		UNIT 2																
3	A 50.75(c)	Finalize Residual Radiation Inventory (WITH SITE CHARACTERIZATION)																
3	A 50.75(c)	Finalize Internals and Vessel Segmenting Details (WITH ACTIVATION ANALYSIS)																
3	A 50.75(c)	Revise Integrated Work Sequence and Schedule	$53,462									$53,462	$8,000	$61,462				
3	A 50.75(c)	Transfer all reactor operating floor CCEs support structures, rigging, internals work platforms and process equipment to position and install (BY UTILITY STAFF)																Utility Staff
3	A 50.75(c)	Remove Unit 2 equipment hatch closure (BY UTILITY STAFF)																Utility Staff
3	A 50.75(c)	Remove Unit 2 CRD missile and reactor cavity missile shields (BY UTILITY STAFF)																Utility Staff
3	A 50.75(c)	Remove Unit 2 CRD mechanisms and cables, air ducts, and reactor vessel head (BY UTILI																Utility Staff
3	A 50.75(c)	Remove, segment, package and bury Unit 2 vessel & vessel head insulation		$182,000					$364,625			$546,625	$180,700	$727,325				

2015 D. C. Cook
Scenario 1
DECON and Permanent On-Site Dry Storage

	Type		Staff Labor,$	Craft Labor,$	Equipment & Materials, $	Packaging, $	Transportation, $	Clean Disposal, $	Contaminated Disposal, $	Energy, $	Other, $	without Contingency, $	Contingency, $	with Contingency, $	Staff Manhours	Craft Manhours	Craft Manhours	
3	A 50.75(c)	Prepare Unit 2 vessel head for shipment as its own container (WITH VESSEL REMOVAL)																
3	A 50.75(c)	Decontaminate and clean up Unit 2 plant areas (BY UTILITY STAFF)																Utility Staff
3	A 50.75(c)	Process liquid and solid radioactive wastes (BY UTILITY STAFF)																Utility Staff
3	A 50.75(c)	Install Unit 2 water cleanup system in fuel transfer canal (BY UTILITY STAFF)																Vessel Removal
3	A 50.75(c)	Segment, package and ship Unit 2 internals as radioactive waste		$2,605,135	$526,565	$90,000	$5,022,524		$38,003,376			$46,247,599	$16,177,800	$62,425,399			47,360	
3	A 50.75(c)	Decontaminate internals work platform and process as LLW (BY UTILITY STAFF)																Vessel Removal
3	A 50.75(c)	Install Unit 2 vessel support structure (WITH VESSEL REMOVAL)																Vessel Removal
3	A 50.75(c)	Segment and process Unit 2 reactor vessel and associated equipment as LLW		$2,701,810	$148,187	$24,000	$2,339,070		$14,901,905			$20,114,971	$6,809,400	$26,924,371			49,100	
3	A 50.75(c)	Decon reactor vessel cutting equipment and work platform; package and process as LLW (I																Vessel Removal
3	A 50.75(c)	Decon, remove, package, ship and bury Unit 2 steam generators		$4,340,246	$1,532,267	$12,800	$823,395		$12,599,366			$19,308,074	$6,344,800	$25,652,874			79,163	
3	A 50.75(c)	Remove, pack, ship and bury Unit 2 Pressurizer		$1,064,197		$800	$71,768		$933,410			$2,070,176	$621,000	$2,691,176			19,407	
3	A 50.75(c)	Decontaminate non-essential structures		$71,104	$40,556	$621	$10,774		$414,819			$537,873	$185,700	$723,573			1,438	
3	A Greenfield	Remove non-essential structures		$2,477,040	$892,900		$331,138	$2,179,243				$5,880,321	$1,104,300	$6,984,621		42,221		
		SUBTOTAL - DECOMMISSIONING ACTIVITY COSTS:	$53,462	$55,250,915	$8,270,855	$641,867	$19,433,198	$3,222,731	$148,460,156			$235,333,185	$75,821,300	$311,154,485		326,298	705,986	
		DECOMMISSIONING PERIOD DEPENDENT																
3	PD 50.75(c)	Utility Staff	$39,164,015									$39,164,015	$5,874,600	$45,038,615	703,601			
3	PD 50.75(c)	DGC Staff	$46,406,897									$46,406,897	$6,961,000	$53,367,897	652,297			
3	PD 50.75(c)	Security	$5,905,496									$5,905,496	$885,800	$6,791,296	234,534			
3	PD 50.75(c)	HP Supplies			$10,971,689							$10,971,689	$2,742,900	$13,714,589				
3	PD 50.75(c)	Equipment			$7,116,150							$7,116,150	$1,779,000	$8,895,150				
3	PD 50.75(c)	Unit 1 Insurance									$1,364,034	$1,364,034	$204,600	$1,568,634				
3	PD 50.75(c)	Unit 2 Insurance									$1,364,034	$1,364,034	$204,600	$1,568,634				
3	PD 50.75(c)	O & M Budget Items			$27,219,510							$27,219,510	$6,804,900	$34,024,410				
3	PD 50.75(c)	Permits & Fees									$7,910,024	$7,910,024	$1,186,500	$9,096,524				
3	PD 50.75(c)	Waste Transfer and Loading		$9,400,235								$9,400,235	$2,240,900	$11,641,135			183,261	
3	PD 50.75(c)	Energy								$12,282,974		$12,282,974	$1,842,400	$14,125,374				
3	PD 50.75(c)	Severance	$2,229,959									$2,229,959	$334,500	$2,564,459				
3	PD 50.75(c)	Small Tools			$1,293,023							$1,293,023	$323,300	$1,616,323				
		SUBTOTAL - DECOMMISSIONING PERIOD DEPENDENT	$93,706,368	$9,400,235	$46,600,371					$12,282,974	$10,638,092	$172,628,040	$31,385,000	$204,013,040	1,590,431		183,261	
		TOTAL PERIOD 3 VESSEL AND INTERNALS REMOVAL COSTS:	$109,297,209	$64,651,150	$165,871,226	$641,867	$19,433,198	$3,222,731	$148,460,156	$14,222,273	$19,925,858	$545,725,669	$138,970,900	$684,696,569	2,066,828	326,298	889,247	
		ACTIVITY																
		UNIT 1																
		Unit 1 Subtotal 10 CFR 50.75(c):		$27,235,225	$3,885,711	$513,646	$10,652,293		$81,242,653			$123,529,529	$40,459,900	$163,989,429			509,519	
		Unit 1 Subtotal 10 CFR 50.54(bb):																
		Unit 1 Subtotal Greenfield:		$14,574,158	$1,244,671		$182,236	$1,043,488				$17,044,553	$3,929,700	$20,974,253		284,077		
		UNIT 2																
		Unit 2 Subtotal 10 CFR 50.75(c):	$53,462	$10,893,388	$2,207,018	$127,600	$8,256,757		$66,802,683			$88,340,908	$30,141,700	$118,482,608			195,030	
		Unit 2 Subtotal 10 CFR 50.54(bb):																
		Unit 2 Subtotal Greenfield:																
		Common																
		Total 10 CFR 50.75(c):		$71,104	$40,556	$621	$10,774		$414,819			$537,873	$185,700	$723,573			1,438	
		Total 10 CFR 50.54(bb):			$111,000,000							$111,000,000	$27,750,000	$138,750,000				
		Total Greenfield		$2,477,040	$892,900		$331,138	$2,179,243				$5,880,321	$1,104,300	$6,984,621		42,221		
		PERIOD DEPENDENT																
		UNIT 1																
		Unit 1 Subtotal 10 CFR 50.75(c):																
		Unit 1 Subtotal 10 CFR 50.54(bb):																
		UNIT 2																
		Unit 2 Subtotal 10 CFR 50.75(c):																
		Unit 2 Subtotal 10 CFR 50.54(bb):																
		Common																
		Total 10 CFR 50.75(c):	$93,706,368	$9,400,235	$46,600,371					$12,282,974	$10,638,092	$172,628,040	$31,385,000	$204,013,040	1,590,431		183,261	
		Total 10 CFR 50.54(bb):	$15,537,379							$1,939,299	$9,287,766	$26,764,444	$4,014,600	$30,779,044	476,396			
		Unit 1, Unit 2 & Common																
		Total 10 CFR 50.75(c):	$93,759,830	$47,599,952	$52,733,656	$641,867	$18,919,824		$148,460,156	$12,282,974	$10,638,092	$385,036,350	$102,172,300	$487,208,650	1,590,431		889,247	
		Total 10 CFR 50.54(bb):	$15,537,379		$111,000,000					$1,939,299	$9,287,766	$137,764,444	$31,764,600	$169,529,044	476,396			
		Total Greenfield		$17,051,199	$2,137,571		$513,374	$3,222,731				$22,924,874	$6,034,000	$27,958,874		326,298		
		PERIOD 4 DECONTAMINATE BALANCE OF SITE COSTS:																
		SPENT FUEL PERIOD DEPENDENT																
4	PD 50.54(bb)	Utility Staff	$10,617,670									$10,617,670	$1,592,700	$12,210,370	215,929			
4	PD 50.54(bb)	Security	$3,253,696									$3,253,696	$488,100	$3,741,796	130,866			
4	PD 50.54(bb)	Insurance									$5,111,529	$5,111,529	$766,700	$5,878,229				
4	PD 50.54(bb)	O & M Budget Items																

	Type		Staff Labor,$	Craft Labor,$	Equipment & Materials, $	Packaging, $	Transportation, $	Clean Disposal, $	Contaminated Disposal, $	Energy, $	Other, $	without Contingency, $	Contingency, $	with Contingency, $	Staff Manhours	Craft Manhours	Craft Manhours
4	PD 50.54(bb)	Permits & Fees									$3,180,346	$3,180,346	$477,100	$3,657,446			
4	PD 50.54(bb)	Waste Transfer and Loading															
4	PD 50.54(bb)	Energy								$1,731,356		$1,731,356	$259,700	$1,991,056			
4	PD 50.54(bb)	Spent Fuel Storage Maintenance Supplies															
4	PD 50.54(bb)	Small Tools															
		SUBTOTAL - SPENT FUEL PERIOD DEPENDENT	**$13,871,366**							**$1,731,356**	**$8,291,875**	**$23,894,597**	**$3,584,300**	**$27,478,897**	**346,795**		
		DECOMMISSIONING ACTIVITIES															
4	A 50.75(c)	Decon, remove, package, ship and dispose of Unit 2 contaminated systems		$13,636,892	$1,131,353	$84,469	$554,325		$4,704,253			$20,111,292	$5,437,200	$25,548,492			267,188
4	A Greenfield	Remove, package, ship and dispose of Unit 2 clean systems		$14,440,360	$1,221,482		$186,260	$1,069,979				$16,918,081	$3,895,600	$20,813,681		281,382	
4	A 50.75(c)	Decon Steam Generator Storage Building	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
4	A 50.75(c)	Decon Unit 2 Reactor Building		$2,529,030	$513,798	$294,710	$1,795,462		$9,297,096			$14,430,095	$4,662,600	$19,092,695			43,847
4	A 50.75(c)	Remove Spent fuel storage racks		$2,561,342	$50,370	$8,348	$45,038		$1,555,798			$4,220,895	$1,220,000	$5,440,895			49,874
4	A 50.75(c)	Decon Auxiliary Building		$5,741,650	$1,291,150	$521,466	$3,162,576		$11,365,733			$22,082,576	$6,729,600	$28,812,176			101,851
4	A 50.75(c)	Perform final radiological survey of all structures		$1,904,750	$35,583							$1,940,333	$463,000	$2,403,333			
4	A 50.75(c)	Perform final survey of the site		$10,033,000	$229,125							$10,262,125	$2,449,000	$12,711,125			
4	A 50.75(c)	Obtain NRC approval															
4	A 50.75(c)	Prepare final report of dismantling program	$51,018									$51,018	$7,700	$58,718	456		
		SUBTOTAL - DECOMMISSIONING ACTIVITY COSTS:	**$51,018**	**$50,847,024**	**$4,472,861**	**$909,992**	**$5,743,661**	**$1,069,979**	**$26,922,880**			**$80,016,415**	**$24,864,700**	**$114,881,115**	**456**	**281,382**	**462,760**
		DECOMMISSIONING PERIOD DEPENDENT															
4	PD 50.75(c)	Utility Staff	$28,677,111									$28,677,111	$4,301,600	$32,978,711	510,377		
4	PD 50.75(c)	DGC Staff	$35,702,442									$35,702,442	$5,355,400	$41,057,842	497,291		
4	PD 50.75(c)	Security	$5,272,273									$5,272,273	$790,800	$6,063,073	209,386		
4	PD 50.75(c)	HP Supplies			$7,925,608							$7,925,608	$1,981,400	$9,907,008			
4	PD 50.75(c)	Equipment			$8,097,070							$8,097,070	$2,024,300	$10,121,370			
4	PD 50.75(c)	Unit 1 Insurance									$1,217,774	$1,217,774	$182,700	$1,400,474			
4	PD 50.75(c)	Unit 2 Insurance									$1,217,774	$1,217,774	$182,700	$1,400,474			
4	PD 50.75(c)	O & M Budget Items			$13,489,789							$13,489,789	$3,372,400	$16,862,189			
4	PD 50.75(c)	Permits & Fees									$5,964,162	$5,964,162	$894,600	$6,858,762			
4	PD 50.75(c)	Waste Transfer and Loading		$8,392,285								$8,392,285	$2,000,600	$10,392,885			163,611
4	PD 50.75(c)	Energy								$10,400,066		$10,400,066	$1,560,000	$11,960,066			
4	PD 50.75(c)	Severance	$819,169									$819,169	$122,900	$942,069			
4	PD 50.75(c)	Small Tools			$1,184,786							$1,184,786	$296,200	$1,480,986			
		SUBTOTAL - DECOMMISSIONING PERIOD DEPENDENT	**$70,470,995**	**$8,392,285**	**$30,697,253**					**$10,400,066**	**$8,399,710**	**$128,360,308**	**$23,065,600**	**$151,425,908**	**1,217,053**		**163,611**
		TOTAL PERIOD 4 DECONTAMINATE BALANCE OF SITE COSTS:	**$84,393,379**	**$59,239,308**	**$35,170,114**	**$909,992**	**$5,743,661**	**$1,069,979**	**$26,922,880**	**$12,131,422**	**$16,691,585**	**$242,271,321**	**$51,514,600**	**$293,785,921**	**1,564,304**	**281,382**	**626,370**
		ACTIVITY															
		UNIT 1															
		Unit 1 Subtotal 10 CFR 50.75(c):															
		Unit 1 Subtotal 10 CFR 50.54(bb):															
		Unit 1 Subtotal Greenfield:															
		UNIT 2															
		Unit 2 Subtotal 10 CFR 50.75(c):		**$16,165,921**	**$1,645,151**	**$379,178**	**$2,349,787**		**$14,001,349**			**$34,541,386**	**$10,099,800**	**$44,641,186**			**311,035**
		Unit 2 Subtotal 10 CFR 50.54(bb):															
		Unit 2 Subtotal Greenfield:		**$14,440,360**	**$1,221,482**		**$186,260**	**$1,069,979**				**$16,918,081**	**$3,895,600**	**$20,813,681**		**281,382**	
		Common															
		Common Subtotal 10 CFR 50.75(c):	**$51,018**	**$20,240,742**	**$1,606,228**	**$529,814**	**$3,207,614**		**$12,921,531**			**$39,556,948**	**$10,869,300**	**$49,426,248**	**456**		**151,725**
		Common Subtotal 10 CFR 50.54(bb):															
		Common Subtotal Greenfield:															
		PERIOD DEPENDENT															
		UNIT 1															
		Unit 1 Subtotal 10 CFR 50.75(c):															
		Unit 1 Subtotal 10 CFR 50.54(bb):															
		UNIT 2															
		Unit 2 Subtotal 10 CFR 50.75(c):															
		Unit 2 Subtotal 10 CFR 50.54(bb):															
		Common															
		Common Subtotal 10 CFR 50.75(c):	**$70,470,995**	**$8,392,285**	**$30,697,253**					**$10,400,066**	**$8,399,710**	**$128,360,308**	**$23,065,600**	**$151,425,908**	**1,217,053**		**163,611**
		Common Subtotal 10 CFR 50.54(bb):	**$13,871,366**							**$1,731,356**	**$8,291,875**	**$23,894,597**	**$3,584,300**	**$27,478,897**	**346,795**		
		Unit 1, Unit 2 & Common															
		Total 10 CFR 50.75(c):	**$70,522,013**	**$44,798,948**	**$33,948,632**	**$908,992**	**$5,557,401**		**$26,922,880**	**$10,400,066**	**$8,399,710**	**$201,458,642**	**$44,034,700**	**$245,493,342**	**1,217,509**		**626,370**
		Total 10 CFR 50.54(bb):	**$13,871,366**							**$1,731,356**	**$8,291,875**	**$23,894,597**	**$3,584,300**	**$27,478,897**	**346,795**		
		Total Greenfield		**$14,440,360**	**$1,221,482**		**$186,260**	**$1,069,979**				**$16,918,081**	**$3,895,600**	**$20,813,681**		**281,382**	

	Type		Staff Labor,$	Craft Labor,$	Equipment & Materials, $	Packaging, $	Transportation, $	Clean Disposal, $	Contaminated Disposal, $	Energy, $	Other, $	without Contingency, $	Contingency, $	with Contingency, $	Staff Manhours	Craft Manhours	Craft Manhours
PERIOD 5 - CLEAN STRUCTURE DEMOLITION COSTS:																	
		SPENT FUEL PERIOD DEPENDENT															
5	PD 50.54(bb)	Utility Staff	$2,534,303									$2,534,303	$380,100	$2,914,403	44,552		
5	PD 50.54(bb)	Security	$1,142,376									$1,142,376	$171,400	$1,313,776	40,644		
5	PD 50.54(bb)	HP Supplies			$109,484							$109,484	$27,400	$136,884	40,644		
5	PD 50.54(bb)	Equipment															
5	PD 50.54(bb)	Insurance									$300,624	$300,624	$45,100	$345,724			
5	PD 50.54(bb)	O & M Budget Items															
5	PD 50.54(bb)	Permits & Fees									$654,924	$654,924	$98,200	$753,124			
5	PD 50.54(bb)	Waste Transfer and Loading															
5	PD 50.54(bb)	Energy								$25,365		$25,365	$3,800	$29,165			
5	PD 50.54(bb)	Spent Fuel Storage Maintenance Supplies															
5	PD 50.54(bb)	Small Tools															
		SUBTOTAL - SPENT FUEL PERIOD DEPENDENT	**$3,676,678**		**$109,484**					**$25,365**	**$955,548**	**$4,767,075**	**$726,000**	**$5,493,075**	**125,839**		
		DECOMMISSIONING ACTIVITIES															
5	A Greenfield	Remove Unit 1 reactor building		$6,713,605	$4,046,917		$1,919,485	$12,635,197				$25,315,204	$4,297,000	$29,612,204		109,447	
5	A Greenfield	Remove Unit 2 reactor building		$6,713,605	$4,046,917		$1,919,485	$12,635,197				$25,315,204	$4,297,000	$29,612,204		109,447	
5	A Greenfield	Remove Auxilary Building		$5,492,728	$3,843,181		$1,107,078	$7,287,449				$17,730,435	$3,241,900	$20,972,335		86,778	
5	A Greenfield	Remove Turbine Building.		$3,926,953	$3,659,567		$1,090,600	$7,178,980				$15,856,100	$2,808,300	$18,664,400		64,508	
5	A Greenfield	Remove Steam Generator Storage Building		$787,930	$1,334,759		$159,894	$1,052,516				$3,335,099	$661,900	$3,996,999		13,110	
5	A Greenfield	Remove Electrical Transformers		$419,247	$16,504		$61,526	$405,000				$902,277	$158,100	$1,060,377		8,297	
5	A Greenfield	Removal of Unit 1 Turbine Generator		$155,209	$9,273		$6,836	$45,000				$216,318	$45,300	$261,618		2,697	
5	A Greenfield	Removal of Unit 1 Main Condenser		$1,349,630	$9,683		$75,023	$493,846				$1,928,182	$390,000	$2,318,182		21,580	
5	A Greenfield	Removal of Unit 2 Turbine Generator		$155,209	$9,273		$6,836	$45,000				$216,318	$45,300	$261,618		2,697	
5	A Greenfield	Removal of Unit 2 Main Condenser		$1,349,630	$9,683		$75,023	$493,846				$1,928,182	$390,000	$2,318,182		21,580	
5	A Greenfield	Remove of Standby Diesel Generators		$30,929	$7,483		$2,051	$13,500				$53,963	$11,000	$64,963		532	
5	A Greenfield	Remove Administration building		$237,595	$211,979		$56,128	$369,471				$875,174	$158,900	$1,034,074		4,105	
5	A Greenfield	Remove Low Level Radwaste building		$919,637	$219,468		$159,275	$1,048,444				$2,346,824	$413,900	$2,760,724		14,743	
		SUBTOTAL - DECOMMISSIONING ACTIVITY COSTS:		**$28,751,958**	**$17,727,996**		**$6,815,557**	**$44,864,075**				**$98,159,584**	**$17,268,400**	**$116,427,984**		**467,681**	
		DECOMMISSIONING PERIOD DEPENDENT															
5	PD Greenfield	Utility Staff	$983,855									$983,855	$147,600	$1,131,455	21,885		
5	PD Greenfield	DGC Staff	$8,592,632									$8,592,632	$1,288,900	$9,881,532	106,299		
5	PD Greenfield	Security	$557,764									$557,764	$83,700	$641,464	21,885		
5	PD Greenfield	HP Supplies															
5	PD Greenfield	Equipment			$3,276,704							$3,276,704	$819,200	$4,095,904			
5	PD Greenfield	Unit 1 Insurance									$428,340	$428,340	$64,300	$492,640			
5	PD Greenfield	Unit 2 Insurance									$428,340	$428,340	$64,300	$492,640			
5	PD Greenfield	O & M Budget Items			$2,473,265							$2,473,265	$618,300	$3,091,565			
5	PD Greenfield	Permits & Fees									$306,416	$306,416	$46,000	$352,416			
5	PD Greenfield	Waste Transfer and Loading		$2,527,775								$2,527,775	$602,600	$3,130,375		46,905	
5	PD Greenfield	Energy								$414,294		$414,294	$62,100	$476,394			
5	PD Greenfield	Severance	$4,084,466									$4,084,466	$612,700	$4,697,166			
5	PD Greenfield	Small Tools			$625,595							$625,595	$156,400	$781,995			
		SUBTOTAL - DECOMMISSIONING PERIOD DEPENDENT	**$14,218,717**	**$2,527,775**	**$6,375,563**					**$414,294**	**$1,163,096**	**$24,699,445**	**$4,566,100**	**$29,265,545**	**150,069**	**46,905**	
		TOTAL PERIOD 5 - CLEAN STRUCTURE DEMOLITION COSTS:	**$17,895,396**	**$31,279,733**	**$24,213,041**		**$6,815,557**	**$44,864,075**		**$439,659**	**$2,118,644**	**$127,626,104**	**$22,560,500**	**$150,186,604**	**275,908**	**514,586**	
		ACTIVITY															
		UNIT 1															
		Unit 1 Subtotal Greenfield (g):		**$8,218,444**	**$4,065,873**		**$2,001,344**	**$13,174,043**				**$27,459,704**	**$4,732,300**	**$32,192,004**		**133,724**	
		Unit 1 Subtotal 10 CFR 50.54(bb):															
		UNIT 2															
		Unit 2 Subtotal Greenfield (g):		**$8,218,444**	**$4,065,873**		**$2,001,344**	**$13,174,043**				**$27,459,704**	**$4,732,300**	**$32,192,004**		**133,724**	
		Unit 2 Subtotal 10 CFR 50.54(bb):															
		Common															
		Common Subtotal Greenfield (g)		**$12,315,069**	**$9,596,248**		**$2,812,869**	**$18,515,989**				**$43,240,175**	**$7,803,800**	**$51,043,975**		**200,233**	
		Common Subtotal 10 CFR 50.54(bb):															
		PERIOD DEPENDENT															
		UNIT 1															
		Unit 1 Subtotal Greenfield (g):															
		Unit 1 Subtotal 10 CFR 50.54(bb):															
		UNIT 2															
		Unit 2 Subtotal Greenfield (g):															
		Unit 2 Subtotal 10 CFR 50.54(bb):															

	Type		Staff Labor, $	Craft Labor, $	Equipment & Materials, $	Packaging, $	Transportation, $	Clean Disposal, $	Contaminated Disposal, $	Energy, $	Other, $	without Contingency, $	Contingency, $	with Contingency, $	Staff Manhours	Craft Manhours	Craft Manhours
		Common															
		Common Subtotal Greenfield (g)	$14,218,717	$2,527,775	$6,375,563					$414,294	$1,163,096	$24,699,445	$4,566,100	$29,265,545	150,069	46,905	
		Common Subtotal 10 CFR 50.54(bb):	$3,676,678		$109,484					$25,365	$955,548	$4,767,075	$726,000	$5,493,075	125,839		
		Unit 1, Unit 2 & Common															
		Total Greenfield (g):	$14,218,717	$31,279,733	$24,103,558		$6,815,557	$44,864,075		$414,294	$1,163,096	$122,859,029	$21,834,500	$144,693,529	150,069	514,586	
		Total 10 CFR 50.54(bb):	$3,676,678		$109,484					$25,365	$955,548	$4,767,075	$726,000	$5,493,075	125,839		
PERIOD 6 - RESTORE SITE COSTS:																	
		SPENT FUEL PERIOD DEPENDENT															
6	PD 50.54(bb)	Utility Staff	$253,892									$253,892	$38,100	$291,992	4,463		
6	PD 50.54(bb)	Security	$114,446									$114,446	$17,200	$131,646	4,072		
6	PD 50.54(bb)	HP Supplies			$9,759							$9,759	$2,400	$12,159	4,072		
6	PD 50.54(bb)	Insurance									$30,117	$30,117	$4,500	$34,617			
6	PD 50.54(bb)	Equipment															
6	PD 50.54(bb)	O & M Budget Items															
6	PD 50.54(bb)	Permits & Fees									$65,612	$65,612	$9,800	$75,412			
6	PD 50.54(bb)	Waste Transfer and Loading															
6	PD 50.54(bb)	Energy								$2,541		$2,541	$400	$2,941			
6	PD 50.54(bb)	Spent Fuel Storage Maintenance Supplies															
6	PD 50.54(bb)	Small Tools															
		SUBTOTAL - SPENT FUEL PERIOD DEPENDENT	$368,338		$9,759					$2,541	$95,729	$476,366	$72,400	$548,766	12,607		
		DECOMMISSIONING ACTIVITIES															
6	A Greenfield	Backfill, grade and landscape site		$183,678								$183,678	$43,800	$227,478		1,757	
		SUBTOTAL - DECOMMISSIONING ACTIVITY COSTS:		$183,678								$183,678	$43,800	$227,478		1,757	
		DECOMMISSIONING PERIOD DEPENDENT															
6	PD Greenfield	Utility Staff	$42,029									$42,029	$6,300	$48,329	940		
6	PD Greenfield	DGC Staff	$425,069									$425,069	$63,800	$488,869	4,698		
6	PD Greenfield	Security	$13,941									$13,941	$2,100	$16,041	626		
6	PD Greenfield	HP Supplies															
6	PD Greenfield	Equipment			$119,433							$119,433	$29,900	$149,333			
6	PD Greenfield	Unit 1 Insurance									$42,912	$42,912	$6,400	$49,312			
6	PD Greenfield	Unit 2 Insurance									$42,912	$42,912	$6,400	$49,312			
6	PD Greenfield	O & M Budget Items			$179,282							$179,282	$44,800	$224,082			
6	PD Greenfield	Permits & Fees									$30,697	$30,697	$4,600	$35,297			
6	PD Greenfield	Waste Transfer and Loading		$253,238								$253,238	$60,400	$313,638		4,699	
6	PD Greenfield	Energy								$22,402		$22,402	$3,400	$25,802			
6	PD Greenfield	Severance	$318,566									$318,566	$47,800	$366,366			
6	PD Greenfield	Small Tools			$8,738							$8,738	$2,200	$10,938			
		SUBTOTAL - DECOMMISSIONING PERIOD DEPENDENT	$799,605	$253,238	$307,454					$22,402	$116,521	$1,499,220	$278,100	$1,777,320	6,264	4,699	
		TOTAL PERIOD 6 - RESTORE SITE COSTS:	$1,167,942	$436,916	$317,212					$24,943	$212,250	$2,159,264	$394,300	$2,553,564	18,871	6,456	
		ACTIVITY															
		UNIT 1															
		Unit 1 Subtotal Greenfield (g):															
		Unit 1 Subtotal 10 CFR 50.54(bb):															
		UNIT 2															
		Unit 2 Subtotal Greenfield (g):															
		Unit 2 Subtotal 10 CFR 50.54(bb):															
		Common															
		Common Subtotal Greenfield (g)		$183,678								$183,678	$43,800	$227,478		1,757	
		Common Subtotal 10 CFR 50.54(bb):															
		PERIOD DEPENDENT															
		UNIT 1															
		Unit 1 Subtotal Greenfield (g):															
		Unit 1 Subtotal 10 CFR 50.54(bb):															
		UNIT 2															
		Unit 2 Subtotal Greenfield (g):															
		Unit 2 Subtotal 10 CFR 50.54(bb):															
		Common															
		Common Subtotal Greenfield (g)	$799,605	$253,238	$307,454					$22,402	$116,521	$1,499,220	$278,100	$1,777,320	6,264	4,699	

2015 D. C. Cook
Scenario 1
DECON and Permanent On-Site Dry Storage

	Type		Staff Labor, $	Craft Labor, $	Equipment & Materials, $	Packaging, $	Transportation, $	Clean Disposal, $	Contaminated Disposal, $	Energy, $	Other, $	without Contingency, $	Contingency, $	with Contingency, $	Staff Manhours	Craft Manhours	Craft Manhours
		Common Subtotal 10 CFR 50.54(bb):	$368,338		$9,759					$2,541	$95,729	$476,366	$72,400	$548,766	12,607		
		Unit 1, Unit 2 & Common															
		Total Greenfield (g):	$799,605	$436,916	$307,454					$22,402	$116,521	$1,682,898	$321,900	$2,004,798	6,264	6,456	
		Total 10 CFR 50.54(bb):	$368,338		$9,759					$2,541	$95,729	$476,366	$72,400	$548,766	12,607		
PERIOD 7 - DRY STORAGE COSTS:																	
		SPENT FUEL ACTIVITIES															
7	A 50.54(bb)	Continue to ship fuel to repository															
		SUBTOTAL - SPENT FUEL ACTIVITIES															
		SPENT FUEL PERIOD DEPENDENT															
7	PD 50.54(bb)	Utility Staff	$1,686,027									$1,686,027	$252,900	$1,938,927	29,639		
7	PD 50.54(bb)	Security	$760,002									$760,002	$114,000	$874,002	27,039		
7	PD 50.54(bb)	Insurance									$200,000	$200,000	$20,000	$220,000			
7	PD 50.54(bb)	O & M Budget Items			$1,175,365							$1,175,365	$117,500	$1,292,865			
7	PD 50.54(bb)	Permits & Fees									$435,709	$435,709	$43,600	$479,309			
7	PD 50.54(bb)	Waste Transfer and Loading															
7	PD 50.54(bb)	Energy								$16,875		$16,875	$1,700	$18,575			
7	PD 50.54(bb)	Equipment			$22,178							$22,178	$2,200	$24,378			
7	PD 50.54(bb)	HP Supplies			$58,779							$58,779	$5,900	$64,679			
7	PD 50.54(bb)	Spent Fuel Storage Maintenance Supplies															
7	PD 50.54(bb)	Severance															
7	PD 50.54(bb)	Small Tools															
		SUBTOTAL - SPENT FUEL PERIOD DEPENDENT	$2,446,029		$1,256,322					$16,875	$635,709	$4,354,935	$557,800	$4,912,735	56,679		
		TOTAL PERIOD 7 - DRY STORAGE COSTS:	$2,446,029		$1,256,322					$16,875	$635,709	$4,354,935	$557,800	$4,912,735	56,679		
		ACTIVITY															
		Common															
		Common Subtotal 10 CFR 50.75(c):															
		Common Subtotal 10 CFR 50.54(bb):															
		PERIOD DEPENDENT															
		Common															
		Common Subtotal 10 CFR 50.75(c):															
		Common Subtotal 10 CFR 50.54(bb):	$2,446,029		$1,256,322					$16,875	$635,709	$4,354,935	$557,800	$4,912,735	56,679		
		Unit 1, Unit 2 & Common															
		Total 10 CFR 50.75(c):															
		Total 10 CFR 50.54(bb):	$2,446,029		$1,256,322					$16,875	$635,709	$4,354,935	$557,800	$4,912,735	56,679		
PERIOD 8 - ISFSI REMOVAL COSTS:																	
		SPENT FUEL ACTIVITIES															
				$3,001,256	$109,980			$175,708	$25,681,914			$28,968,858	$10,432,000	$39,400,858		375	54,839
		SUBTOTAL - SPENT FUEL ACTIVITIES		$3,001,256	$109,980			$175,708	$25,681,914			$28,968,859	$10,432,000	$39,400,858		375	54,839
		SPENT FUEL PERIOD DEPENDENT															
8	PD 50.54(bb)	Utility Staff	$3,679,010									$3,679,010	$551,900	$4,230,910			
8	PD 50.54(bb)	DGC Staff	$3,784,123									$3,784,123	$567,600	$4,351,723			
8	PD 50.54(bb)	Security	$1,211,638									$1,211,638	$181,700	$1,393,338			
8	PD 50.54(bb)	HP Supplies			$44,630							$44,630	$11,200	$55,830			
8	PD 50.54(bb)	Insurance									$569,934	$569,934	$85,500	$655,434			
8	PD 50.54(bb)	Equipment			$1,962,711							$1,962,711	$196,300	$2,159,011			
8	PD 50.54(bb)	O & M Budget Items			$906,576							$906,576	$226,600	$1,133,176			
8	PD 50.54(bb)	Permits & Fees									$869,819	$869,819	$130,500	$1,000,319			
8	PD 50.54(bb)	Waste Transfer and Loading		$1,221,960								$1,221,960	$291,300	$1,513,260			
8	PD 50.54(bb)	Energy								$100,829		$100,829	$15,100	$115,929			
8	PD 50.54(bb)	Spent Fuel Storage Maintenance Supplies															
8	PD 50.54(bb)	Severance	$773,659									$773,659	$116,000	$889,659			
8	PD 50.54(bb)	Small Tools			$42,232							$42,232	$10,600	$52,832			
		SUBTOTAL - SPENT FUEL PERIOD DEPENDENT	$9,448,430	$1,221,960	$2,956,149					$100,829	$1,439,752	$15,167,120	$2,384,300	$17,551,420			
		TOTAL PERIOD 8 - ISFSI REMOVAL COSTS:	$9,448,430	$4,223,216	$3,066,128			$175,708	$25,681,914	$100,829	$1,439,752	$44,135,978	$12,816,300	$56,952,278		375	54,839
		ACTIVITY															
		Common															

2015 D. C. Cook
Scenario 1
DECON and Permanent On-Site Dry Storage

Type	Staff Labor, $	Craft Labor, $	Equipment & Materials, $	Packaging, $	Transportation, $	Clean Disposal, $	Contaminated Disposal, $	Energy, $	Other, $	without Contingency, $	Contingency, $	with Contingency, $	Staff Manhours	Craft Manhours	Craft Manhours
Total 10 CFR 50.75(c):															
Common Subtotal Greenfield (g)															
Common Subtotal 50.54 (bb)		$3,001,256	$109,980			$175,708	$25,681,914			$28,968,858	$10,432,000	$39,400,858		375	54,839
PERIOD DEPENDENT															
Common															
Total 10 CFR 50.75(c):															
Common Subtotal Greenfield (g)															
Common Subtotal 50.54 (bb)	$9,449,430	$1,221,960	$2,956,149					$100,829	$1,439,752	$15,167,120	$2,384,300	$17,551,420			
Unit 1, Unit 2 & Common															
Total 10 CFR 50.75(c):															
Total Greenfield (g):															
Total 50.54(bb)	$9,448,430	$4,223,216	$3,066,128			$175,708	$25,681,914	$100,829	$1,439,752	$44,135,978	$12,816,300	$56,952,278		375	54,839
TOTAL ACTIVITY COSTS:															
UNIT 1															
SUBTOTAL UNIT 1 10 CFR 50.75(C) COSTS FOR PERIODS 1 - 6		$32,037,678	$5,148,773	$513,646	$10,652,293		$85,912,778			$134,265,170	$43,679,200	$177,944,370		5,760	509,519
SUBTOTAL UNIT 1 10 CFR 50.54(bb) COSTS FOR PERIODS 1 - 6															
SUBTOTAL UNIT 1 GREENFIELD COSTS FOR PERIODS 1 - 6		$22,792,603	$5,310,545		$2,183,580	$14,217,531				$44,504,258	$8,662,000	$53,166,258		417,801	
UNIT 2															
SUBTOTAL UNIT 2 10 CFR 50.75(C) COSTS FOR PERIODS 1 - 6	$53,462	$31,861,763	$5,115,231	$506,778	$10,606,544		$85,474,157			$133,617,936	$43,460,800	$177,078,736		5,760	506,065
SUBTOTAL UNIT 2 10 CFR 50.54(bb) COSTS FOR PERIODS 1 - 6															
SUBTOTAL UNIT 2 GREENFIELD COSTS FOR PERIODS 1 - 6		$22,658,805	$5,287,355		$2,187,604	$14,244,022				$44,377,786	$8,627,900	$53,005,686		415,106	
COMMON															
SUBTOTAL COMMON 10 CFR 50.75(C) COSTS FOR PERIODS 1 - 6	$9,731,336	$22,033,067	$3,246,784	$530,435	$3,218,388		$13,336,350			$52,096,360	$13,318,300	$65,414,660	100,196	24,960	153,163
SUBTOTAL COMMON 10 CFR 50.54(bb) COSTS FOR PERIODS 1 - 6	$783,758	$136,688,877	$224,490,000							$361,962,635	$88,824,800	$450,787,435	7,904	33,280	
SUBTOTAL COMMON GREENFIELD COSTS FOR PERIODS 1 - 6		$14,976,787	$10,489,148		$3,144,008	$20,695,232				$49,304,175	$8,951,900	$58,266,075		244,211	
TOTAL PERIOD DEPENDENT COSTS															
UNIT 1															
SUBTOTAL UNIT 1 10 CFR 50.75(C) COSTS FOR PERIODS 1 - 6	$27,536,583		$734,369					$3,482,181	$3,218,992	$34,972,125	$5,319,400	$40,291,525	161,307		
SUBTOTAL UNIT 1 10 CFR 50.54(bb) COSTS FOR PERIODS 1 - 6															
SUBTOTAL UNIT 1 GREENFIELD COSTS FOR PERIODS 1 - 6															
UNIT 2															
SUBTOTAL UNIT 2 10 CFR 50.75(C) COSTS FOR PERIODS 1 - 6															
SUBTOTAL UNIT 2 10 CFR 50.54(bb) COSTS FOR PERIODS 1 - 6															
SUBTOTAL UNIT 2 GREENFIELD COSTS FOR PERIODS 1 - 6															
COMMON															
SUBTOTAL COMMON 10 CFR 50.75(C) COSTS FOR PERIODS 1 - 6	$222,465,437	$17,792,520	$91,198,875					$26,884,824	$22,249,717	$380,591,373	$67,781,200	$448,372,573	3,414,844		346,872
SUBTOTAL COMMON 10 CFR 50.54(bb) COSTS FOR PERIODS 1 - 6	$38,112,937		$1,486,131					$4,547,036	$24,140,604	$68,286,708	$10,391,500	$78,678,208	1,079,792		
SUBTOTAL COMMON GREENFIELD COSTS FOR PERIODS 1 - 6	$15,018,322	$2,781,013	$8,683,017					$436,696	$1,279,617	$26,198,664	$4,844,200	$31,042,864	156,333	51,604	
ANNUAL SPENT FUEL STORAGE	$2,446,029		$1,256,322					$16,875	$635,709	$4,354,935	$557,800	$4,912,735	56,679		
UNIT 1, UNIT 2 & COMMON															
GRAND TOTAL ACTIVITY COSTS FOR PERIODS 1-6	$10,568,556	$283,048,581	$259,087,836	$1,550,859	$31,992,416	$49,156,784	$184,723,286			$820,128,318	$215,524,900	$1,035,653,218	108,100	1,148,878	1,168,746
GRAND TOTAL PERIOD DEPENDENT COSTS FOR PERIODS 1-6	$303,133,279	$20,573,532	$100,102,391					$35,350,737	$50,888,929	$510,048,869	$88,336,300	$598,385,169	4,812,276	51,604	346,872
ANNUAL SPENT FUEL STORAGE	$2,446,029		$1,256,322					$16,875	$635,709	$4,354,936	$557,800	$4,912,735	56,679		
GRAND TOTAL	$313,701,835	$303,622,113	$359,190,227	$1,550,859	$31,992,416	$49,156,784	$184,723,286	$35,350,737	$50,888,929	$1,330,177,187	$303,861,200	$1,634,038,387	4,920,377	1,198,482	1,515,618
ISFSI DECONTAMINATION AND REMOVAL	$9,448,430	$4,223,216	$3,066,128			$175,708	$25,681,914	$100,829	$1,439,752	$44,135,978	$12,816,300	$56,952,278		375	54,839
SUBTOTAL UNIT 1 DECON PROGRAM FINANCIAL PLANNING COST FOR 10 CFR 50.75(c):	$27,536,583	$32,037,678	$5,883,142	$513,646	$10,652,293		$85,912,778	$3,482,181	$3,218,992	$169,237,294	$48,998,600	$218,235,894	161,307	5,760	509,519
SUBTOTAL UNIT 1 DECON PROGRAM FINANCIAL PLANNING COST FOR 10 CFR 50.54(bb):															
SUBTOTAL UNIT 1 DECON PROGRAM FINANCIAL PLANNING COST FOR GRENNFIELD (g):		$22,792,603	$5,310,545		$2,183,580	$14,217,531				$44,504,258	$8,662,000	$53,166,258		417,801	
SUBTOTAL UNIT 2 DECON PROGRAM FINANCIAL PLANNING COST FOR 10 CFR 50.75(c):	$53,462	$31,861,763	$5,115,231	$506,778	$10,606,544		$85,474,157			$133,617,936	$43,460,800	$177,078,736		5,760	506,065
SUBTOTAL UNIT 2 DECON PROGRAM FINANCIAL PLANNING COST FOR 10 CFR 50.54(bb):															
SUBTOTAL UNIT 2 DECON PROGRAM FINANCIAL PLANNING COST FOR GRENNFIELD (g):		$22,658,805	$5,287,355		$2,187,604	$14,244,022				$44,377,786	$8,627,900	$53,005,686		415,106	
SUBTOTAL COMMON DECON PROGRAM FINANCIAL PLANNING COST FOR 10 CFR 50.75(c):	$232,196,772	$39,825,587	$94,445,659	$530,435	$3,218,388		$13,336,350	$26,884,824	$22,249,717	$432,687,732	$81,099,500	$513,787,232	3,515,040	24,960	500,034
SUBTOTAL COMMON DECON PROGRAM FINANCIAL PLANNING COST FOR 10 CFR 50.54(bb):	$38,896,695	$136,688,877	$225,976,131					$4,547,036	$24,140,604	$430,249,343	$99,216,300	$529,465,643	1,087,696	33,280	
SUBTOTAL COMMON DECON PROGRAM FINANCIAL PLANNING COST FOR GRENNFIELD (g):	$15,018,322	$17,756,800	$17,172,164		$3,144,008	$20,695,232		$436,696	$1,279,617	$75,502,839	$13,796,100	$89,298,939	156,333	295,816	
TOTAL UNIT 1 & 2 DECON PROGRAM FINANCIAL PLANNING COST FOR 10 CFR 50.75(c):	$259,786,817	$103,725,029	$105,444,032	$1,550,859	$24,477,225		$184,723,286	$30,367,006	$25,468,708	$735,542,962	$173,558,900	$909,101,862	3,676,348	36,480	1,515,618
TOTAL UNIT 1 & 2 DECON PROGRAM FINANCIAL PLANNING COST FOR 10 CFR 50.54(bb):	$38,896,695	$136,688,877	$225,976,131					$4,547,036	$24,140,604	$430,249,343	$99,216,300	$529,465,643	1,087,696	33,280	
TOTAL UNIT 1 & 2 DECON PROGRAM FINANCIAL PLANNING COST FOR GRENNFIELD (g):	$15,018,322	$63,208,207	$27,770,064		$7,515,191	$49,156,784		$436,696	$1,279,617	$164,384,882	$31,086,000	$195,470,882	156,333	1,128,722	
GRAND TOTAL	$313,701,835	$303,622,113	$359,190,227	$1,550,859	$31,992,416	$49,156,784	$184,723,286	$35,350,737	$50,888,929	$1,330,177,187	$303,861,200	$1,634,038,387	4,920,377	1,198,482	1,515,618

APPENDIX C

CASH FLOW TABLE

2015 D. C. Cook
Scenario 1 Draft
DECON and Permanent On-Site Dry Storage

Scenario 1 - Yearly costs:

UNIT 1

Year	Labor	Material & Equipment	Packaging, Transportation & Disposal	Energy	Other	Contingency for 10 CFR 50.75(c) and Greenfield	Total for 10 CFR 50.75(c) and Greenfield	10 CFR 50.54(bb) costs with Contingency
2034	$1,598,700	$42,600	$0	$202,200	$186,900	$308,800	$2,339,200	
2035	$8,715,300	$232,400	$0	$1,102,100	$1,018,800	$1,683,600	$12,752,200	
2036	$8,715,300	$232,400	$0	$1,102,100	$1,018,800	$1,683,600	$12,752,200	
2037	$8,622,300	$257,100	$111,900	$1,075,800	$994,500	$1,720,500	$12,782,100	
2038	$5,011,000	$1,272,500	$5,282,900	$0	$0	$3,485,700	$15,052,100	
2039	$11,865,200	$1,456,000	$26,572,600	$0	$0	$12,597,400	$52,491,200	
2040	$11,865,200	$1,456,000	$26,572,600	$0	$0	$12,597,400	$52,491,200	
2041	$11,865,200	$1,456,000	$26,572,600	$0	$0	$12,597,400	$52,491,200	
2042	$5,890,300	$722,800	$13,191,700	$0	$0	$6,253,900	$26,058,700	
2043	$0	$0	$0	$0	$0	$0	$0	
2044	$0	$0	$0	$0	$0	$0	$0	
2045	$1,955,700	$967,500	$3,611,100	$0	$0	$1,126,100	$7,660,400	
2046	$5,467,600	$2,705,000	$10,095,900	$0	$0	$3,148,300	$21,416,800	
2047	$795,200	$393,400	$1,468,300	$0	$0	$457,900	$3,114,800	
2048	$0	$0	$0	$0	$0	$0	$0	
2049	$0	$0	$0	$0	$0	$0	$0	
2050	$0	$0	$0	$0	$0	$0	$0	
	$82,367,000	$11,193,700	$113,479,600	$3,482,200	$3,219,000	$57,660,600	$271,402,100	
						Rounding Allowance:	$52	
							$271,402,152	

UNIT 2

Year	Labor	Material & Equipment	Packaging, Transportation & Disposal	Energy	Other	Contingency for 10 CFR 50.75(c) and Greenfield	Total for 10 CFR 50.75(c) and Greenfield	10 CFR 50.54(bb) costs with Contingency
2034	$0	$0	$0	$0	$0	$0	$0	
2035	$0	$0	$0	$0	$0	$0	$0	
2036	$0	$0	$0	$0	$0	$0	$0	
2037	$115,000	$30,300	$111,900	$0	$0	$77,100	$334,300	
2038	$4,772,100	$1,249,900	$5,140,100	$0	$0	$3,375,400	$14,537,500	
2039	$3,106,600	$626,300	$21,337,500	$0	$0	$8,554,000	$33,624,400	
2040	$3,106,600	$626,300	$21,337,500	$0	$0	$8,554,000	$33,624,400	
2041	$3,106,600	$626,300	$21,337,500	$0	$0	$8,554,000	$33,624,400	
2042	$6,441,400	$769,800	$13,471,900	$0	$0	$6,486,800	$27,169,900	
2043	$9,729,000	$911,200	$5,717,500	$0	$0	$4,448,800	$20,806,500	
2044	$9,729,000	$911,200	$5,717,500	$0	$0	$4,448,800	$20,806,500	
2045	$8,204,800	$1,552,800	$7,283,600	$0	$0	$3,983,600	$21,024,800	
2046	$5,467,600	$2,705,000	$10,095,900	$0	$0	$3,148,300	$21,416,800	
2047	$795,200	$393,400	$1,468,300	$0	$0	$457,900	$3,114,800	
2048	$0	$0	$0	$0	$0	$0	$0	
2049	$0	$0	$0	$0	$0	$0	$0	
2050	$0	$0	$0	$0	$0	$0	$0	
	$54,573,900	$10,402,500	$113,019,200	$0	$0	$52,088,700	$230,084,300	
						Rounding Allowance:	$121	
							$230,084,421	

Common

Year	Labor	Material & Equipment	Packaging, Transportation & Disposal	Energy	Other	Contingency for 10 CFR 50.75(c) and Greenfield	Total for 10 CFR 50.75(c) and Greenfield	10 CFR 50.54(bb) costs with Contingency
2034	$492,200	$0	$0	$0	$0	$73,900	$566,100	$10,049,200
2035	$2,683,100	$0	$0	$0	$0	$402,700	$3,085,800	$54,781,600
2036	$2,683,100	$0	$0	$0	$0	$402,700	$3,085,800	$54,781,600
2037	$4,085,400	$371,300	$0	$100,700	$76,900	$736,200	$5,370,500	$57,146,900
2038	$60,563,500	$15,497,800	$22,700	$4,196,200	$3,217,300	$14,231,200	$97,728,700	$150,968,500
2039	$29,983,900	$13,489,700	$833,400	$3,485,800	$3,019,000	$9,272,900	$60,084,700	$48,110,900
2040	$29,983,900	$13,489,700	$833,400	$3,485,800	$3,019,000	$9,272,900	$60,084,700	$48,110,900
2041	$29,983,900	$13,489,700	$833,400	$3,485,800	$3,019,000	$9,272,900	$60,084,700	$48,110,900
2042	$30,757,000	$11,867,600	$3,080,300	$3,395,200	$2,843,300	$10,035,400	$61,978,800	$28,282,800
2043	$31,519,000	$10,268,500	$5,295,500	$3,305,900	$2,670,100	$10,787,100	$63,846,100	$8,734,900
2044	$31,519,000	$10,268,500	$5,295,500	$3,305,900	$2,670,100	$10,787,100	$63,846,100	$8,734,900
2045	$27,160,700	$10,396,300	$8,476,800	$2,222,000	$1,991,800	$9,872,300	$60,119,900	$6,917,700
2046	$19,334,100	$10,625,800	$14,189,700	$275,600	$773,800	$8,229,500	$53,428,500	$3,654,400
2047	$4,048,500	$1,852,800	$2,063,700	$62,500	$229,100	$1,518,800	$9,775,400	$1,080,300
2048	$0	$0	$0	$0	$0	$0	$0	$0
2049	$0	$0	$0	$0	$0	$0	$0	$0
2050	$0	$0	$0	$0	$0	$0	$0	$0
	$304,797,300	$111,617,700	$40,924,400	$27,321,400	$23,529,400	$94,895,600	$603,085,800	$529,465,500
						Rounding Allowance:	$371	$ 143
							$603,086,171	$529,465,643
	$136,940,900	**$21,596,200**	**$226,498,800**	**$3,482,200**	**$3,219,000**	**$109,749,300**	**$1,104,572,745**	**$529,465,643**
								$1,634,038,387

Annual Storage Cost	$4,912,700
ISFSI decommissioning Year 1	$33,123,000
ISFSI decommissioning Year 2	$23,829,300
	$56,952,300

COMPARISON OF THE 2012 AND 2015 D.C. COOK DECOMMISSIONING COST ESTIMATES, Rev. 2

Summary

The following is a comparison of the costs for Scenario 1 from the 2012 Decommissioning Cost Estimate and Scenario 1 from the 2015 Decommissioning Cost Estimate. Costs have increased $303,305,160 or 22.79% over the three years, approximately. This comparison identifies the major differences in costs due to changes in the scope-of-work and estimating logic included in the estimates. The material inventory for the 2015 estimate was recreated from site specific drawings and the plant database, as such, there are changes from the inventory used in the previous estimates. This comparison focuses on the following areas: spent fuel storage, undistributed costs, waste disposal, component removal and contingency. Table 1 provides a summary of the total costs for both studies.

Table 1
2012 Scenario 1 vs. 2015 Scenario 1 Total Costs
(Costs include contingency)

Category	2012	2015	
Period Dependent	$405,369,121	$510,048,869	$104,679,749
Activity	$676,073,007	$820,128,318	$144,055,311
Contingency	$249,291,100	$303,861,200	$54,570,100
	$1,330,733,228	**$1,634,038,387**	**$303,305,160**
Decommissioning 50.75 c	$802,374,964	$909,101,862	$106,726,899
Spent Fuel 50.54(bb)	$386,242,332	$529,465,643,	$143,223,311
Greenfield	$142,115,933	$195,470,882	$53,354,949
	$1,330,733,228	**$1,634,038,387**	**$303,305,160**

Spent Fuel Storage

As shown in Table 1, there is an increase in the spent fuel storage cost of $143.2 million. The major reason for this increase is due to the increase in the estimate to construct the expansion to the spent fuel storage pad. In 2012 the estimate for the expanded pad was based on the actual cost to construct the existing pad. The 2012 estimate for the pad expansion was $25.1 million, before contingency, for 120 additional storage casks. In January of 2015 an estimate was developed by site personnel for the expansion of the pad. This estimate was $135 million, before contingency, for 111 additional storage casks. In both cases the expansion would be sufficient to hold all spent fuel on site after both units shutdown.

This increase was somewhat offset by the decrease in the cost of the spent fuel storage casks. While the cost of the casks increased, from $1.93 million each to $2 million each, fewer casks were estimated to be required. In 2012 it was estimated that 120 additional casks would be required after shutdown to empty the spent fuel pool. Based on a revised analysis of spent fuel discharges this number was reduced to 111 additional casks. Table 4 provides a summary of spent fuel storage costs.

Except for one modification, the Utility Staff person levels associated with the post-shutdown storage of spent fuel have remained the same as in the 2012 study. The Utility staff level during period 4 was increased from 14.25 to 33 in the 2015 study. This increase is due to the in-pool spent fuel cooling period increasing from 5 years to 7 years. This increase causes spent fuel to remain in the spent fuel pool for the majority of period 4, requiring a larger staff. Table 2 provides a comparison of the utility staff.

There were a few changes to the Security Staff levels associated with spent fuel storage. This modifications are a result of new information provided by AEP. Period 4 was also modified due to the increase from 5 years to 7 years for in-pool cooling. Table 3 provides a comparison of the security staff.

Both scenarios assume that spent fuel will remain on site indefinitely. The annual costs for long storage increased approximately $432,646 or 9.66%. The main reason for this increase is due a change in the methodology used to calculate the O&M expenses during decommissioning. Since KCES received a more detailed list of these expenses a more accurate of assessment of the costs incurred during decommissioning was made. A more detailed description of the O&M costs is provided below. In addition, the spent fuel storage maintenance costs were included in the O&M budget and these values were used in the 2015 study, as opposed to being estimated separately in the 2012 study. Table 4 provides a summary of the dry spent fuel storage costs.

Table 2 – Utility Staff Levels

Period	2012 Spent Fuel	2015 Spent Fuel
1		
2	33	33
3	33	33
4	14.25	33
5	14.25	14.25
6	14.25	14.25
7	14.25	14.25

Table 3 – Security Staff Levels

Period	2012 Spent Fuel	2015 Spent Fuel
1		
2	21	24
3	21	20
4	12	20
5	12	13
6	12	13
7	12	13

Table 4 – Spent Fuel Storage Costs
(Costs include contingency)

	2012 Totals	2015 Totals	Cost Difference
Undistributed with contingency	$59,888,277	$78,678,208	$18,789,930
Modify pool systems, security and control room	$6,030,177	$6,105,735	$75,558
New pad construction cost	$30,861,277	$167,181,700	$136,320,423
Additional cask costs	$289,462,600	$277,500,000	-$11,962,600
	$386,242,332	$529,465,643	$143,223,311
Number of new casks	120	111	
Cost per cask, excluding contingency	$1,929,750	$2,000,000	$70,250
Period 7 Duration, months	12	12	
Annual Period 7 costs	$4,480,089	$5,912,735	$432,646

Undistributed Costs

Table 5 provides a summary of the undistributed costs for both studies. While undistributed costs increased 26.41% overall, there are variations within specific categories. Permits & Licenses, Insurance, Energy, Small Tools, O&M Budget Items and Equipment had the largest cost in increase, 43.30%, 84.27%, 48.94%, 41.11%, 214% and 51.89%, respectively. Health Physics Supplies costs decreased 7.75%. These differences are due to more than just normal inflation.

Table 5 – 2012 Scenario 1 vs. 2015 Scenario 1 Total Costs
(Costs include contingency)

Category	2012 Totals	2015 Totals	% Change
Utility Staff	$132,634,100	$136,026,214	2.56%
DGC Staff	$111,197,900	$123,131,415	10.73%
Permits & Licenses	$22,097,100	$31,665,294	43.30%
Insurance	$14,954,700	$27,556,345	84.27%
Security	$29,192,400	$30,348,012	3.96%
Waste Transfer and Loading	$21,307,100	$25,478,032	19.58%
Energy	$27,307,100	$40,671,912	48.94%
Health Physics (HP) Supplies	$19,275,900	$25,342,861	31.47%
Small Tools	$4,168,400	$5,881,953	41.11%
Severance Pay	$52,958,900	$61,910,768	16.90%
O & M Budget Items	$22,280,800	$70,014,563	214.24%
Equipment	$16,637,800	$25,270,536	51.89%
Spent Fuel Maintenance	$3,233,900	Included in O&M	N/A
Totals	**$477,246,000**	**$603,297,905**	**26.41%**

The post shut-down schedule duration increased from 97 months in 2012 to 112 months in 2015. There were two reasons for this increase. The first is due to a revision to the reactor vessel and reactor vessel internals removal duration. The duration increased from 11 months in 2012 to 21 months in 2015. This increase was due to a modification in the calculations based more current information. The second is that the in-pool spent fuel cooling period was increased from 5 years to 7 years. The result was that the period dependent costs increased more than the increase due to inflation.

Utility staff costs increased 2.56% from 2012 to 2015. The total Utility Staff man-years increased from 889 in 2012 to 1,066 in 2015 due to the schedule change. Based on the information provided by AEP, the average base salary increased approximately 25% from 2012 to 2015. Fringes and payroll tax decreased from 69.73% to 29.84%, a 57.21% decrease. This decrease is due to a revised method for determining the Utility overhead percentage rate. The combined effect is to decrease the average cost per man-year 14.47%. Table 6 provides a summary of these values.

Table 6 –Utility Staff Costs
(Costs do not include contingency unless noted)

Category	2012 Totals	2015 Totals	% Change
Total man-years	889	1,066	19.90%
Fringe and payroll tax markup	69.73%	29.84%	-57.21%
Average $/man-year w/ contingency	$149,153	$127,574	-14.47%

Decommissioning General Contractor (DGC) costs increased 10.73% from 2012 to 2015. The total DGC man-years increased from 615 in 2012 to 709 in 2015 due to the schedule change. The increase in cost due to the schedule change is somewhat offset by a decrease in the average cost per man year of 3.91%. This decrease is due to variations in the average salaries provided by various industry sources. Table 7 provides a summary of these values.

Table 7 –DGC Staff Costs
(Costs do not include contingency unless noted)

Category	**2012 Totals**	**2015 Totals**	**% Change**
Total man-years	615	709	15.24%
Average $/man-year w/ contingency	$180,794	$173,721	-3.91%

Insurance costs increased 84.27% from the 2012 study to the 2015. The annual nuclear property insurance premiums provided by AEP increased 45.36% from 2012 while the annual nuclear liability premiums provided by AEP increased 44.33%. Cost also increased as a result of the extended in-pool spent fuel cooling, from 5 to 7 years. The estimating logic incorporated in the 2015 estimate is similar to that incorporated in the 2012 estimate. Table 8 provides a summary of the inputs used in both studies.

Table 8 – Insurance Premiums

	2012 Totals	**2015 Totals**
NEIL -Primary	$2,984,079	$4,337,542
Facility (Basic) -	$943,562	$1,361,796

Security costs increased 3.96% from 2012 to 2015. The total Security man-years increased from 381 in 2012 to 502 in 2015 due to the schedule change. The decrease in salaries, as seen in Table 9, was offset by the schedule change and a slightly larger staff level. The adjustment in the staff level is due to more detailed information provided by AEP. Table 9 provides a summary of this information.

Table 9 – Security Costs
(Costs do not include contingency unless noted)

Category	**2012 Totals**	**2015 Totals**	**% Change**
Total man-years	381	502	31.66%
Average base salary - guard only	$43,035	$41,330	-3.96%
Average base salary - manager only	$108,500	$90,943	-16.18%
Average base salary - supervisor only	$84,208	$54,912	-0.58%
Average $/man-year w/ contingency	$76,561	$60,421	-21.04%

Waste transfer and loading costs increased 19.58% from 2012 to 2015. The logic and crew size used in the 2015 estimate is the same as that used in the 2015 estimate. This increase is driven primarily by the increase in Periods 3 and 4 durations.

Energy costs increased 48.94%. There are two factors associated with this increase. One is the increase in the Period 3 and 4 durations. The other is due to an increase in the cost of electricity from $0.0225/kw-hr to $0.0767/kw-hr.

Small tool costs increased by 41.11%. The basis for these costs remains the same as used in 2012, based on the R. S. Means specified factor of 1% of craft labor costs. The increase in costs is due to the increase craft labor due to the schedule change.

O & M Budget item costs increased by 214.24%. The basis for these costs is similar to that used in 2012 in that the cost for each period was based on a percent of that incurred during operations. In 2012 the percentages were applied to the operating costs at the department level. The basis was supplied by AEP in 2006, escalated for each subsequent update, and was not sufficiently detailed to allow for the percentages to be applied at a lower level. In 2015 AEP supplied a much more detailed version of these costs, 457 line items versus 190 in 2006. The new information allowed for the percentages to be applied on a line item basis. As an example, in 2012 the same percentage was applied to all costs in the business services department. In 2015, a separate percentage was applied to each cost category within the business services department. This added detail allows for a better tracking of the costs through the decommissioning.

Severance costs increased 16.90%, from $53.0 million to $61.9 million, from 2012 to 2015. The increase is due in part to the increase in the average cost per man-year for the Utility staff. The number of employees eligible for receiving severance, as reported by AEP, increased from 1051 in 2012 to 1198 in 2015. The severance costs are based on two weeks of pay for every year of service.

Equipment costs increased 51.89% from 2012 to 2015. There was a slight adjustment to the methodology used to calculate the equipment costs, causing an increase in overall costs. In addition, the increase in the duration of Periods 3 and 4 also caused an increase in costs.

Component Removal and Waste Disposal

Structures and component removal costs increased 11.26%. The systems and structures inventory for the 2012 study were developed in the 1990's and have been used in every estimate since then. Over the years the unit cost factors have been revised to better reflect industry experience. Since the original inventory remained the property of a previous company, it was necessary to redo the inventory to allow for a better distribution to the appropriate unit cost factors. This was done for the 2015 study.

Based on the new inventory there was some change in waste volumes. Since the original inventories are not available it is not possible to perform a detailed comparison of the two inventories. There is now a detailed material takeoff to support the 2015 study. As an example, Table 10 provides a summary of the Reactor Building waste volumes.

Table 10 – Reactor Building Waste Volumes

	2012	2015
Contaminated Waste	363,988	260,877
Clean Waste	688,608	2,580,935

Structures and component removal costs are affected by two main components, waste disposal and labor costs. As discussed below, waste disposal costs decreased 3.47% while labor costs, see Table 12, increased 0.85% on average.

Table 13 summarizes the change in costs between 2012 and 2015. Based on the changes identified above, decontamination, removal and disposal costs increased 11.26%. The decontamination and contaminated removal costs decreased while the demolition and disposal of clean structures increased. The change in inventory is the main reasons for these changes, see the example in Table 10.

The decontamination of structures decreased 4.04% from 2012 to 2015. The same basic logic used in the 2012 study was used in the 2015 study. Basically, the majority of the building material inside the Containment Building will be removed and sent out as Bulk Survey For Release (BSFR) as opposed to decontaminate, survey and release. This not only reduces the survey requirement but eliminates the need for scabbling of the surfaces. The removal of contaminated systems decreased 20.44%. The majority of the cost decrease is due to the revision to the system and structure inventories.

Table 11 provides a comparison of the disposal rates and volumes between the 2012 study and the 2015 study. While the disposal costs either increased or stay the same, the overall costs decreased due to a larger volume going out as BSFR. Smelting was not included in the 2015 study due to uncertainties in the industry.

Table 11 – Waste Summary

Waste Disposal (without contingency)	**2012**	**2015**	
Contaminated Disposal, Includes surcharges	$191,363,101	$184,723,286	-3.47%
EnergySolutions rate, $/cu ft	$158.54	$171.84	8.39%
EnergySolutions volume, cu. ft.	278,239	190,644	-31.48%
Smelting rate, $/lb	$2.10		
Smelting volume, cu. ft.	188,051	Not Used	
WCS disposal rate, $/cu ft	$208.79	$208.79	0.00%
WCS disposal volume, cu. ft.	70,018	3,946	-94.36%
BSFR rate, $/lb	$0.13	$0.25	92.31%
BSFR volume, cu. ft.	2,879,629	3,389,951	17.72%

The 2015 estimate assumes that the reactor vessel and reactor internals will be removed and disposed of based on the same methodology as in the 2012 study. This waste is assumed to be disposed of at either the EnergySolutions facility in Clive, Utah or the WCS facility in Andrews, Texas in the 2015 estimate. The increase is due, in part to the increase in disposal costs for B and C waste. Class B waste was increased from $300.00 per cubic foot to $2,680.00 and Class C from $1,200.00 per cubic foot to $2,680.00. There was also a modification to the vessel removal labor costs based on recent experience, increasing the labor costs for the 2015 study.

The increase in the disposal cost for the steam generators is due to general increases in labor and equipment and material costs.

Table 12 – Labor Rates

Craft Labor Billing Rates	**2012 Totals**	**2015 Totals**	**% Change**
Laborer	$43.89	$45.28	3.16%
Craftsmen	$62.72	$62.27	-0.71%
Foreman	$70.23	$70.29	0.09%

Table 13 – Major Component Removal and Disposal
(Costs do not include contingency unless noted)

	2012 Totals	**2015 Totals**	**% Change**
Decon Structures	$53,650,749	$51,480,639	-4.04%
Decon & Remove Contaminated Systems	$51,434,478	$40,923,280	-20.44%
Remove Clean Systems	$31,698,818	$33,962,634	7.14%
Demolition of Structures	$63,126,837	$98,312,543	55.74%

Reactor Internals	$82,364,670	$92,495,199	12.30%
Reactor Vessel	$36,368,825	$40,229,943	10.62%
Steam Generator and Pressurizer	$40,549,368	$42,756,500	5.44%
Spent Fuel Racks	$4,249,314	$4,220,895	-0.67%
Total	**$363,443,058**	**$404,381,633**	

Contingency

The average effective contingency for Scenario 1 in 2012 was 23.05%. The average effective contingency for Scenario 1 in 2015 is 22.84%. The methodology for calculating the contingency is the same for both estimates. Since each cost category, labor; equipment & materials; packaging; transportation and disposal has a separate contingency factor applied, the increase is due to the difference in the cost for each category.

DIRECT TESTIMONY OF DONALD L. SCHNEIDER, JR.
DIRECTOR, ADVANCED METERING
DUKE ENERGY BUSINESS SERVICES LLC
ON BEHALF OF DUKE ENERGY INDIANA, INC.
CAUSE NO. 44526 BEFORE THE
INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Donald L. Schneider, Jr., and my business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as Director, Advanced Metering by Duke Energy Business Services LLC, a service company subsidiary of Duke Energy Corporation ("Duke Energy"), and a non-utility affiliate of Duke Energy Indiana, Inc. ("Duke Energy Indiana" or "Company").

Q. WHAT IS YOUR PRIMARY RESPONSIBILITY AS DIRECTOR, ADVANCED METERING?

A. As Director, Advanced Metering, I am responsible for managing the project execution of all Advanced Metering Infrastructure ("AMI") related projects for all Duke Energy jurisdictions.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science Degree in Electrical Engineering from the University of Evansville in 1986. Upon graduation, I was employed by Duke Energy Indiana (then known as Public Service Indiana) as an electrical engineer.

Throughout my career with Duke Energy, I have held various positions of increasing responsibility in the areas of engineering and operations, including distribution planning, distribution design, field operations, and capital budgets. Prior to my current position with the Company, I was General Manager, Midwest Premise Services, responsible for managing all of Duke Energy's Midwest premise service and meter reading departments. In 2008, prior to the Duke Energy/Progress Energy merger, I was promoted to a position responsible for managing the project execution for all Grid Modernization projects in the field, including both AMI and Distribution Automation ("DA") devices, for all legacy Duke Energy jurisdictions.

Q. ARE YOU A REGISTERED PROFESSIONAL ENGINEER LICENSED IN THE STATE OF INDIANA?

A. Yes. I have been registered as a professional engineer with the State Board of Registration for Professional Engineers in the state of Indiana since 1995.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to discuss the Company's plans to implement AMI technology in Indiana, including deployment timelines, as well as provide background on Duke Energy's experiences deploying AMI in other jurisdictions. Through this testimony I am also sponsoring exhibits to demonstrate the positive business case for deploying AMI technology in Duke Energy Indiana's service territory.

II. AMI TECHNOLOGY

Q. PLEASE DESCRIBE THE PROPOSED METERING PLAN.

A. Duke Energy Indiana is proposing implementation of an advanced metering solution across its Indiana service territory. The Company estimates this effort will include approximately 817,000 advanced meters and associated communications and IT infrastructure. The project consists of a four-year phased deployment of most meters for Duke Energy Indiana residential and commercial customers. However, some larger commercial and industrial (C&I) customers in Indiana already have an advanced metering solution including the ability to automatically communicate with the Company. There is no need to change out these large C&I meters.

Q. PLEASE DESCRIBE THE METERING SOLUTION THE COMPANY IS PROPOSING.

A. The AMI metering solution is not a simple meter change-out. In addition to changing out the meters, the AMI metering solution covers all of the components necessary to communicate with the advanced meters and collect usage data and event information from them. The overall solution includes advanced meters, a two-way communication network, and central computer systems. Advanced meters – often referred to as "smart meters" – are electricity meters that have advanced features beyond traditional electricity meters. Some of the advanced features include two-way communications capability, interval usage measurement, tamper detection, voltage and reactive power measurement, and net metering capability.

In order to create the two-way communications path to the advanced meters, the Company will install a neighborhood area network ("NAN"). This represents the network connecting advanced meters to a collection point. The NAN will use a mesh architecture, as depicted in figure "A" – AMI Solution Architecture below. Mesh networks are flexible in that the meters within the mesh network establish an optimized communication path to a collection point either through other meters or, in some cases, through network range extenders. Range extenders may be used to extend the mesh signal to meters that would have otherwise been outside the reach of the mesh network. Mesh communications throughout the NAN occur using wireless radio frequency ("RF") transmissions in the 902-928 MHz spectrum band.

Collection points serve as the interchange between NAN communications and the Company's central computer systems. Collection point devices aggregate the communications from all advanced meters within a NAN and communicate the information over a Wide Area Network ("WAN") to the central computer systems, and they also communicate commands, firmware/program updates, and instructions from the central computer systems out to the advanced meters within a NAN. The WAN is the two-way communication network used to move data and instructions between the collection points and the central computer systems. The Company will utilize a virtual private network over a public cellular network in Indiana as its WAN.

The third component of the AMI solution is the central computer systems. The central computer systems of an AMI solution include three major systems. One is referred to as the head-end system, and this is the system responsible for sending information to and receiving information from the advanced meters. Another system is the network management system, which is the system responsible for maintaining the health and reliability of the communications network. The third system is the Meter Data Management ("MDM") System, and it is responsible for processing the data and events from the advanced meters. Processing involves validating, editing, estimating, and packaging data for billing and other uses. Additional systems are interfaced to conduct other corporate functions, but are not considered part of the AMI solution.

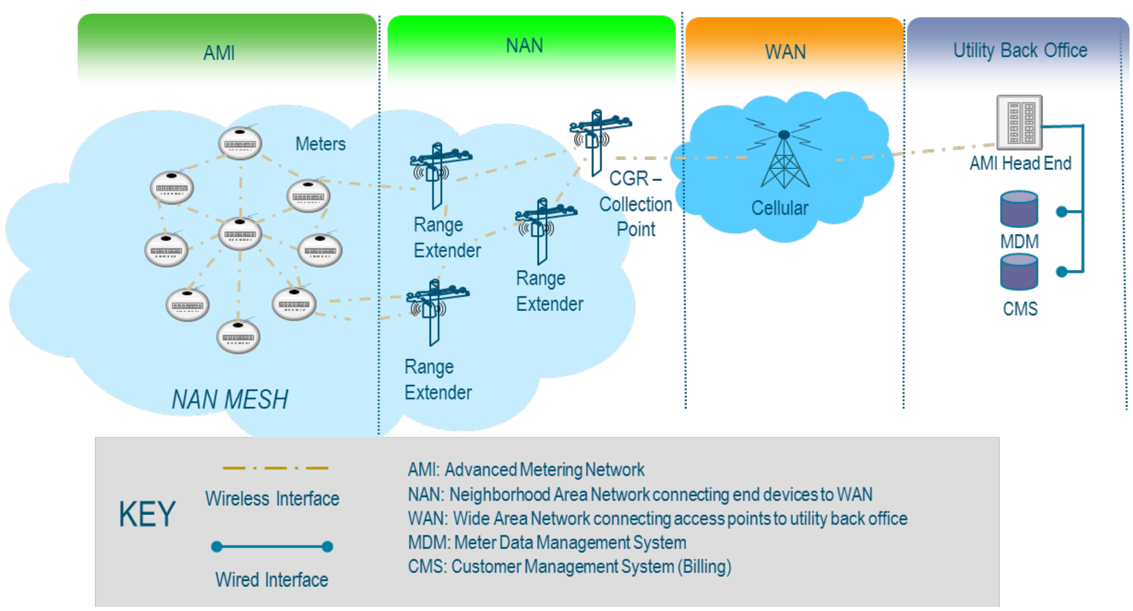


Figure "A" – AMI Solution Architecture

Q. PLEASE DESCRIBE THE PRIMARY VENDORS FOR THE PROPOSED METERING SOLUTION.

A. The Company plans to implement the Itron OpenWay solution. This is the same solution that Duke Energy is deploying in Ohio as its meter solution for commercial and industrial customers and in the Carolinas for residential, commercial and industrial customers. The Duke Energy AMI project will include deployment of advanced meters and range extenders manufactured by Itron, as well as collection point devices manufactured by Cisco, which are called Cisco Grid Routers ("CGRs"). As noted above, the AMI solution also involves expansion of the Company's current central computer systems, which are being used today for deployments in Ohio and Carolinas. The head-end system is from Itron; the network management system is from Cisco, and the MDM is from Oracle. All three of these companies are considered leaders in their respective industries.

Q. WHAT TYPE OF DATA WILL THE NEW METERS BE SENDING TO THE COMPANY?

A. The Company plans to collect interval kilowatt-hour ("kWh") usage on all meters for billing purposes as well as time tagged event and alert data such as tamper alerts. Other site specific parameters such as voltage, amperage, phase angle, etc., may be collected as needed.

Q. WHY IS THE COMPANY INTERESTED IN COLLECTING THIS TYPE OF DATA?

A. Outside of the kWh usage information for billing purposes, various alerts will allow the Company to better manage the distribution grid. Tamper alerts will allow for more efficient theft detection, allowing the Company to pinpoint investigations, rather than simply conduct random meter audits. Site-specific parameters will be used to improve system models for system planning and system operations purposes.

Q. DID THE COMPANY CONSIDER OTHER METERING TECHNOLOGIES?

A. Yes. Duke Energy issued a request for quotes ("RFQ") to the leading AMI solution vendors within the United State for bid proposals in 2013. A team of individuals with diverse business and technical backgrounds performed the evaluation of these bids and recommended Itron as the preferred solution provider based on technical expertise, commercial merits, and price. The team also concluded Itron was best aligned with the Company's overarching grid strategy and architectural guidance.

Four qualified vendors responded to our bids; three of the vendors proposed an RF mesh solution and one vendor proposed an RF point-to-point solution. These four vendors represent the large majority of AMI deployments in the United States. One reason RF technologies are now predominant in North America is economics. Due to the nature of the grid in North America (low number of customers per distribution transformer) and the ease of installation and functionality of wireless communication solutions compared to wired communication solutions, most utilities that have deployed AMI solutions have opted to install RF technologies.

Q. WHAT ABOUT AUTOMATED METER READING ("AMR") SOLUTIONS?

A. An AMR solution is more advanced than our current technology (no remote read capability – walk by reads). However, an AMR solution typically requires a drive-by meter read each month. With the additional capabilities of AMI over AMR, there has been a general shift in the electric utility industry over the past 6 to 8 years away from installing AMR. Utilities are opting to install AMI instead, due to the additional business value and customer options which AMI can offer. For a utility like Duke Energy Indiana which has not previously invested in AMR, making the switch directly from walk-by meters to the increased functionality and cost savings of an AMI solution was the better choice.

III. DEPLOYMENT PROCESS AND SCHEDULE

Q. PLEASE DESCRIBE THE PROPOSED DEPLOYMENT TIMEFRAME FOR THE AMI METERS AND COMMUNICATIONS EQUIPMENT.

A. Duke Energy Indiana plans a four-year deployment schedule for the AMI meters and communications equipment. Deployment will occur over the first four years of the seven-year T&D Infrastructure Improvement Plan ("T&D Plan") with a ramp up for years two and three.

Q. HOW IS THE INSTALLATION OF AMI DEVICES COORDINATED THROUGHOUT THE DEPLOYMENT?

A. Based on previous experience deploying AMI in other service territories, Duke Energy Indiana anticipates deploying the AMI technology by zones. See

Petitioner's Exhibit D-1 for an example of deployment zones. To efficiently and effectively deploy the metering solution, the Company first strategically places CGRs in a deployment zone. Then the Company installs the meters that will communicate through that CGR or a neighboring CGR, allowing some overlap for redundancy purposes. This process is repeated on a rolling basis, in that the Company will begin new zones while deployment in other zones is underway. Once deployment is complete in a zone, there may still be ongoing work to relocate CGRs or install range extenders in order to optimize the communication network.

Q. HAS DUKE ENERGY DEPLOYED AMI METERS IN OTHER JURISDICTIONS?

A. Yes, AMI meters are becoming the standard for Duke Energy and for the industry as a whole. In fact, the penetration rate for smart meters (which include two-way communication) is almost 40% in the U.S., according to a report from Innovation Electricity Efficiency (IEE), an Institute of The Edison Foundation. Our affiliate, Duke Energy Ohio, plans to complete its AMI deployment in 2014, which included a blend of earlier generation AMI technology as well as the wireless mesh AMI technology proposed for implementation in Indiana. Duke Energy is incrementally rolling out AMI meters in North Carolina, South Carolina, and Florida, and is considering further deployments.

Q. DESCRIBE THE LESSONS LEARNED FROM THOSE DEPLOYMENTS THAT WILL BE HELPFUL IN INDIANA.

A. Duke Energy Indiana is proposing technology proven not only across the industry, but specifically proven by Duke Energy in other jurisdictions, particularly Duke Energy Ohio and the Carolinas. Each service territory presents its own challenges, and Duke Energy Indiana will benefit from learned lessons in those areas. Our customer engagement is a proven strategy, and will likely require only minor tweaks between jurisdictions. The Company learned how to deploy multiple AMI technologies in Ohio, including the technology proposed for Indiana. Because AMI deployments will continue in the Carolinas throughout the Indiana deployment, those project teams can share experiences and lessons learned for any emergent challenges that may arise in Indiana. Each service territory presents its own challenges for communication network optimization in terms of topography and population density, among other things. The Company has extensive experience in the approaches to communication network optimization and is working with solid vendors with an even broader range of experience in that area.

Q. PLEASE DESCRIBE THE CUSTOMER ENGAGEMENT / COMMUNICATION PROCESS DURING THE AMI DEPLOYMENT.

A. Petitioner's Exhibit D-2 depicts the timeline for customer engagement as the Company deploys meters in a zone. Through these multiple outreach attempts, customers are informed of the upcoming installation and have ample time to reach out to the Company if they have any questions that aren't answered in the literature. Once a customer's meter is certified, they receive a notice informing them that their interval usage data can now be accessed via their customer web-portal. The project team also reaches out to city / town councils ahead of the meter deployment to discuss the AMI solution and deployment methodology.

Q. WHAT HAS THE RESPONSE BEEN TO DUKE ENERGY'S CUSTOMER OUTREACH EFFORTS?

A. Duke Energy's AMI deployment customer engagement process has been greatly appreciated by customers, regulators, and customer advocates. As a result of this approach in Ohio, very few customers initially refused AMI meter installation. Of those who did refuse installation, the Company offered to meet with those customers individually and ensure that all their concerns were heard and addressed. We continue to monitor and adapt our outreach efforts as customer inquiries evolve.

IV. <u>CUSTOMER CONCERNS</u>

Q. WHAT ARE SOME OF THE CUSTOMER CONCERNS THE COMPANY HAS EXPERIENCED WHILE DEPLOYING AN AMI SOLUATION IN OTHER STATES?

A. Overall customer concerns related to our AMI deployments have been minimal and are generally focused on one of five areas: 1) communications, 2) installation, 3) service disconnection for non-access, 4) bill accuracy, and 5) smart meter installation refusal. In most cases, we use existing processes to manage complaints. For issue-based questions and complaints (*e.g.*, AMI meter installation refusal), we connect the customer with internal subject matter experts to discuss concerns in detail. In some situations, we have been able to use our Envision Centers to explain our deployment program, and that has proven helpful. Duke Energy Indiana witness Mr. Russ Atkins will highlight our plans for an Indiana Envision Center in his testimony. We believe the Envision Center concept has proven successful in other jurisdictions and can be improved upon through lessons learned for our planned Indiana deployment.

The AMI meter installation refusals typically relate to concerns around data security, data privacy and health concerns attributed to wireless RF emissions.

Duke Energy Indiana is committed to using best practices identified through the Company's deployments in several states and to being responsive to customer concerns, while creating the least amount of disruption to the customer during deployment. We continue to review feedback and adjust our communications and processes as needed.

Q. PLEASE DESCRIBE THE APPROACH TO CYBERSECURITY FOR THE AMI SOLUTION.

A. As we implement the AMI metering solution, the Company will follow IT security policies that are based upon National Institute for Standards and Technology ("NIST") guidelines for securing SmartGrid assets and risk management. The data and systems associated with every component of the AMI metering solution are secured against both internal and external security threats. During and after implementation of the AMI solution, periodic audits and security penetration tests will be performed to ensure the appropriate policies have been applied to defend the potentially affected systems.

Q. PLEASE EXPLAIN HOW THE DATA COLLECTED FROM THE PROPOSED AMI SOLUTION IS TREATED FROM A PRIVACY PERSPECTIVE.

A. Duke Energy Indiana has collected data from meters since the Company's inception and has privacy policies in place to protect customer information. The Company will treat the data from an AMI metering solution with the same level of privacy protection. Customer privacy is of the utmost concern to Duke Energy Indiana, and the Company does not release private customer information to third parties without the authorization of the customer.

Q. SOME PEOPLE HAVE HEALTH CONCERNS REGARDING "SMART METERS". CAN YOU COMMENT ON THIS?

A. Numerous reliable studies by third party and governmental resources show that wireless smart meters – or AMI meters – do not pose any health risk. In the United States, the Federal Communications Commission ("FCC") sets limits for public exposure to RF emissions and requires that all radio communicating devices be tested to ensure that they comply with the FCC standards. The FCC public exposure limits are set at a safety factor 50 times less than the threshold for potentially adverse biological effects, and AMI meters emit low-power RF waves at a fraction of those FCC limits. We plan to include information on the safety of AMI devices in our customer communication plans.

V. CUSTOMER SERVICE

Q. WHAT CHANGES WILL CUSTOMERS SEE IN THEIR SERVICE AFTER THE NEW METERING SOLUTION IS INSTALLED?

A. After AMI meters are installed and certified, customers will be able to view their previous day's hourly interval usage data on the Duke Energy Indiana customer web-portal. Another change in service for customers with certified AMI meters is that they will no longer require monthly walk-by meter reads or estimated bills when the meter cannot be read. Instead, meter reads will be reported back to the Company through the AMI communication network. When customers move in or out of properties, they will no longer need to wait for technicians to arrive to activate or deactivate service, because that can be performed remotely for AMI meters. AMI, working in parallel with grid automation efforts, assists the Company in the outage restoration process. We can have more information about where an outage has occurred and through the ability of pinging meters, we can identify isolated outages more readily and restore service more efficiently.

Q. WHAT NEW INFORMATION WILL BE AVAILABLE TO DUKE ENERGY INDIANA CUSTOMERS ON THE PORTAL WEBSITE?

A. Hourly interval usage data will be accessible to customers on the Duke Energy Indiana customer web-portal the next day. The portal uses interval data in several different views: hourly energy use by day or week, daily energy use by billing cycle, month or week, and average energy use by day-of-week over a billing cycle of month. Those customers that have multiple electric meters will see usage broken out by meter, if desired. With this new data, customers are more empowered to understand their energy usage and save energy. Petitioner's Exhibit D-3 provides an illustrative example of screen shots showing the customer usage information available on the Duke Energy Indiana customer web-portal.

Q. WHAT FUTURE OFFERINGS COULD BE POSSIBLE THROUGH THE AMI?

A. Provided customer interest and Commission approval, the AMI metering solution could enable such offerings as dynamic pricing and flexible billing and payment options, such as prepayment and pick your due date. The Company proposes that these future offerings be developed in coordination with the OUCC and interested stakeholders in a collaborative fashion. As discussed in more detail below, the deployment schedule for AMI meters is phased-in over four years. The Company proposes collaborative discussions begin upon approval of its Plan, so that future pilot offerings could be developed for roll-out soon after meters are installed.

VI. <u>AMI BUSINESS CASE</u>

Q. HAS DUKE ENERGY PREPARED A BUSINESS CASE FOR THE NEW METERING SOLUTION?

A. Yes. We have looked at proposed costs of our chosen AMI metering solution and compared those costs to estimated benefits. There are benefits from AMI solutions that can be readily quantified, such as savings from meter reading, and those that are much more difficult to quantify, such as assumed energy efficiency savings due to better customer understanding of their usage and reduced safety incidents by elimination of walk-by meter reading and driving. The Company took the approach of limiting the business case cost / benefit analysis to include only the quantifiable benefits, while also discussing the potential for future benefits from new customer offerings of products and services. Petitioner's Exhibit D-4 provides a summary of the cost/benefit results.

Q. PLEASE DESCRIBE THE COSTS ASSOCIATED WITH THE PROPOSED METERING SOLUTION INCLUDED IN THE BUSINESS CASE.

A. The estimated cost for deploying the AMI solution in Duke Energy Indiana is about $181 M over the first four years of the 7-Year T&D Plan. That includes approximately $28 M in the first year, $52 M in the second, $56 M in the third, and $45 M in the fourth year. The costs include the cost of technology components and the installation labor –including the AMI meters, communication devices/grid routers, and IT systems.

In order to complete a 20-year business case, additional costs were added in the out-years to reflect additional estimated expenditures necessary for ongoing maintenance of the equipment as well as some equipment replacement costs as equipment nears its life expectancy.

Q. PLEASE DESCRIBE THE BENEFITS THAT WERE INCLUDED IN THE BUSINESS CASE SUPPORTING THE AMI SOLUTION.

A. As stated, we did not attempt to quantify every conceivable benefit from AMI, but rather focused on quantifiable benefits. The main quantifiable benefits arise from the elimination of monthly manual meter reads, enhanced theft detection that can be conducted without a truck roll, and the ability to conduct customer-requested service disconnects and reconnects remotely. Also included are the quantifiable benefits from remote reconnects for non-pay. We have excluded benefits for savings in remote disconnects for non-pay, as under current Commission rules, the Company is still required to roll a truck in those situations. However, this is an additional area of savings that could be achieved in the future. The Company may propose alternate communication efforts for non-pay disconnects (based on results of monitoring in-person notifications) in the future T&D Plan proceedings, so these additional saving may be realized.

The business case also recognizes that the AMI solution serves as an enabler to provide qualitative benefits expected to be achieved over time. Examples include; integration of advanced technologies such as distributed generation, energy storage and electric vehicles with our distribution system; ability to offer our customers advanced products and services, such as choose your own due date, usage alerts, pay-as-you-go offers, and time-differentiated peak pricing rates; ability to offer expanded options for energy efficiency and demand response programing.

The Company proposes to work collaboratively with interested stakeholders on these customer offer-related qualitative benefits as the AMI solution is rolled-out.

Q. WHAT WERE THE RESULTS OF THE AMI BUSINESS CASE THE COMPANY PERFORMED?

A. Based on the business case, over a 20-year period, the net present value ("NPV") of the AMI solution is estimated to be approximately $38M. Essentially, the analysis demonstrates that over 10.4 years the investment in the advanced metering solution pays for itself.

Q. ARE THE ESTIMATED COSTS OF THE AMI SOLUTION INVESTMENTS INCLUDED IN THE 7-YEAR T&D PLAN JUSTIFIED BY INCREMENTAL BENEFITS ATTRIBUTABLE TO THE PLAN?

A. Yes, the business case cost / benefit analysis demonstrates that there are quantifiable benefits that outweigh the costs of the plan. Additionally, there are qualitative benefits and future functionality that will result in further benefits.

Q. IN YOUR OPINION, ARE THE COST/BENEFIT ESTIMATES REASONABLE BASED ON YOUR REVIEW AND EXPERIENCE?

A. Yes.

VII. CONCLUSION

Q. WERE PETITIONER'S EXHIBITS D-1 THROUGH D-4 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PREFILED TESTIMONY?

A. Yes, it does.

VERIFICATION

I hereby verify under the penalties of perjury that the foregoing representations are true to the best of my knowledge, information and belief.

Signed: Donald L. Schneider, Jr. Dated: August 29, 2014

Donald L. Schneider, Jr.

AMI Installation Process by Zone

Deployment Design

- Analyze RF Clusters
- Determine CGR Locations

Mesh Infrastructure and Meter Installations

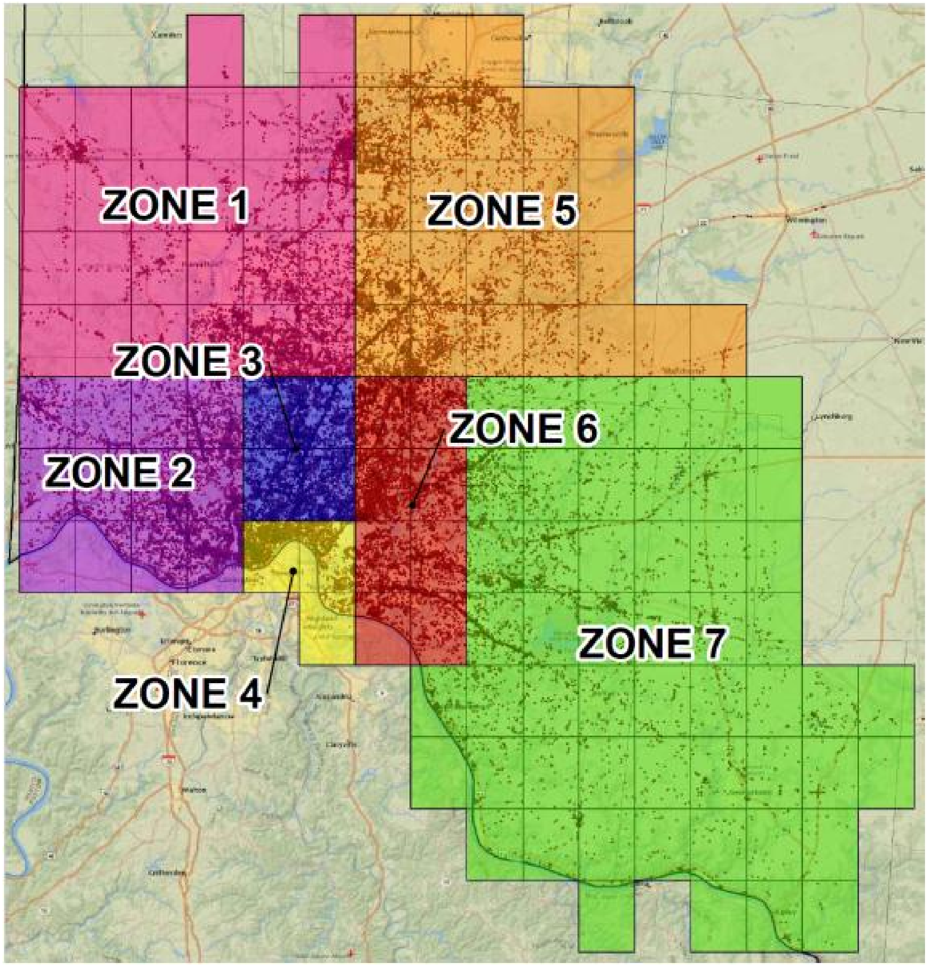
- Install CGRs
- Install Meters

Mesh Mitigation

- Monitor Meter Readings
- Install RF Range Extenders where necessary

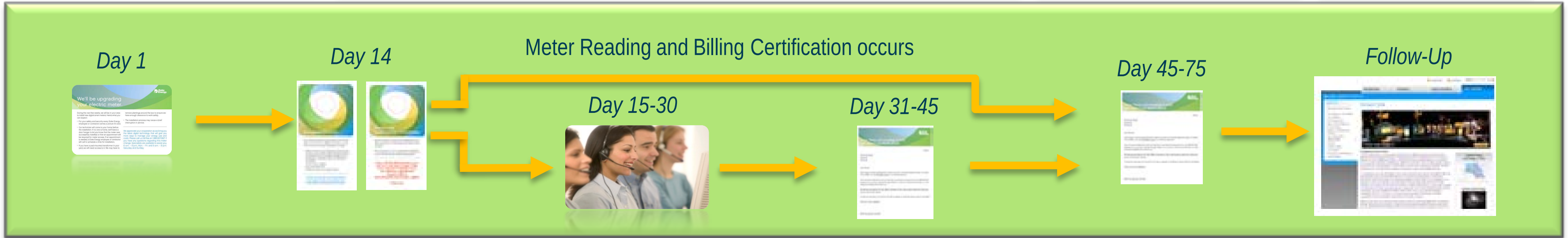
Direct Connect Installation

- Install Direct Connect Electric Meters where necessary



AMI Customer Engagement

Planning → Install Meters & Reading for Certification → Meter Certification → Services



Postcard Notification	Canvas and Door Hanger	Outbound Calls (if required)	Letter (if required)	Certification Letter	Online Services
First proactive communication sent by Duke Energy to customers. Large Business account managers will reach out to applicable large account customers in advance as needed.	Attempt to notify customer on day of meter exchange or following exchange. Where customer interaction is necessary for the exchange, a door hanger is left encouraging customer to call and schedule an appointment.	If meter exchange is unsuccessful, Duke proactively attempts to contact customers to schedule an appointment.	If outbound calling attempts are unsuccessful, a letter may be sent to encourage customers to schedule an appointment.	Meter certification occurs 30 to 60 days after the new meter is installed. Customer is invited to sign up for Online Services to view daily energy use.	Customer can access the Duke Energy web portal where they can opt to monitor their energy use online.

Customer Usage Data
From Duke Energy Customer Portal

DUKE ENERGY® | Online Services

Contact Us | Messages | (Log Out) | [redacted]

Add an Account

Account Number [redacted]

Address [redacted]

My Account Home

Billing & Payment

- Pay Bill
- View Bill
- Payment Activity
- Compare Bills
- Bill Inserts
- Billing FAQs
- Third Party Notification

My Bill Preferences

Energy Analysis

My Products & Services

Account Summary

[redacted]

Account status as of 9/9/2014

Last Payment Received	$200.00
7/31/2014 - Thank you!	
Amount Due	**$0.00**
	Pay
Bill Summary ending 7/18/2014	View
Previous Balance/Other Charges	$0.00
Budget Billing/Equal Payment Plan Amount	$173.00
Last bill amount due 8/11/2014	**($63.14)**

For more detailed information on your bill, please see the links under Billing & Payment.

Bill Highlights

[redacted]

Out with the old. In with the new.

Phase into energy-saving CFLs and LEDs for up to 92% off retail.

Shop now

How does my home use energy?

[redacted]

Get personalized information on how you use your energy.

Complete a quick home profile for personalized information!

Hourly Energy Usage

Viewable over a Day or Week Timeline

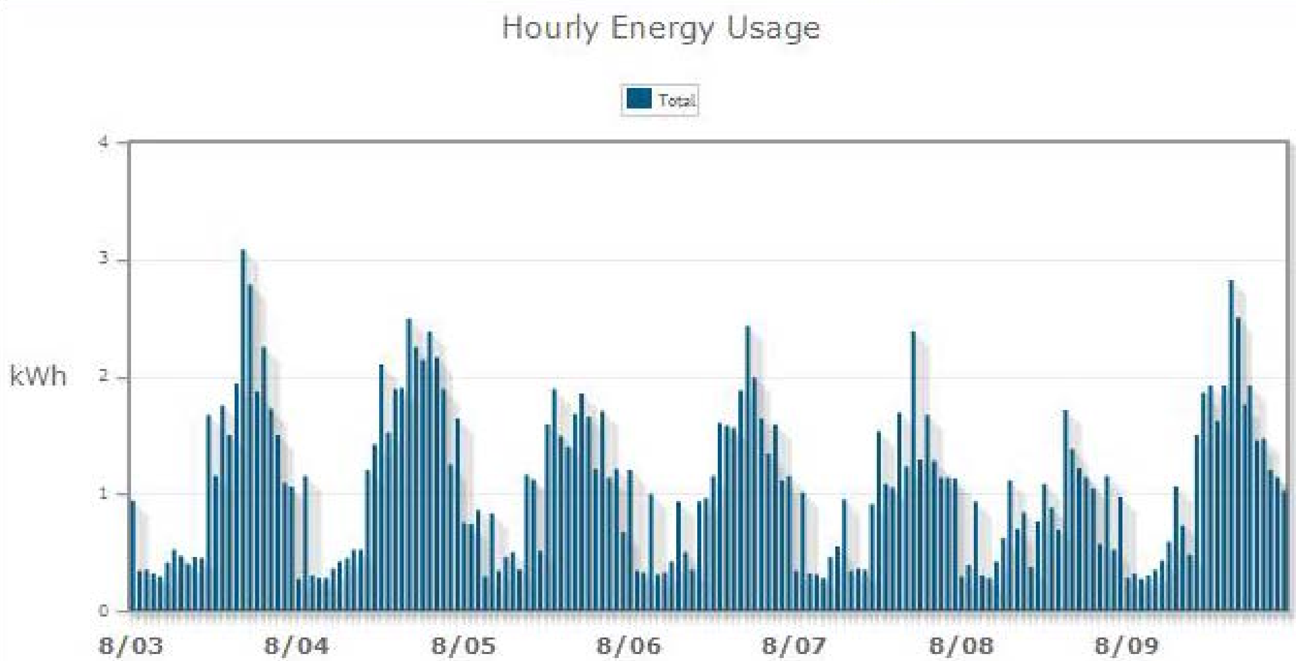
Daily Energy Usage

To change Meter, Graph, or Date, make new selections from the options below.

Meter:

Graph: Hourly Energy Usage **Date:** 08/04/2014

Period: Week Day Export Data



Use your daily charts first to identify the days with the highest energy usage, then continue to these hourly charts to identify key hours of energy usage.

Terms And Conditions

Daily Energy Usage

Viewable over a Billing Cycle, Month or Week Timeline

Daily Energy Usage

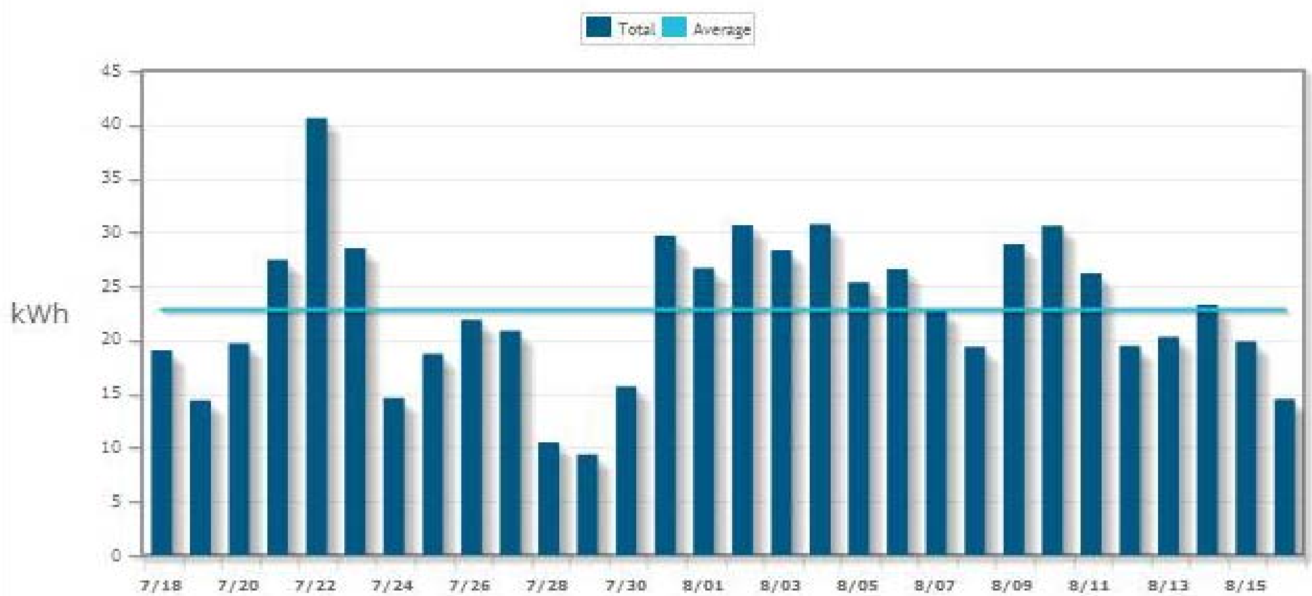
To change Meter, Graph, or Date, make new selections from the options below.

Meter: [redacted]

Graph: Daily Energy & Average **Date:** 08/04/2014

Period: Billing Cycle Month Week Export Data

Daily Energy and Average



Look for trends or irregularities in the daily usage bars, relative to one another and to the average. Look to the Day-Of-Week chart for confirmation.

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Average Energy Usage

Viewable by Day-of-Week over a Billing Cycle or Month Timeline

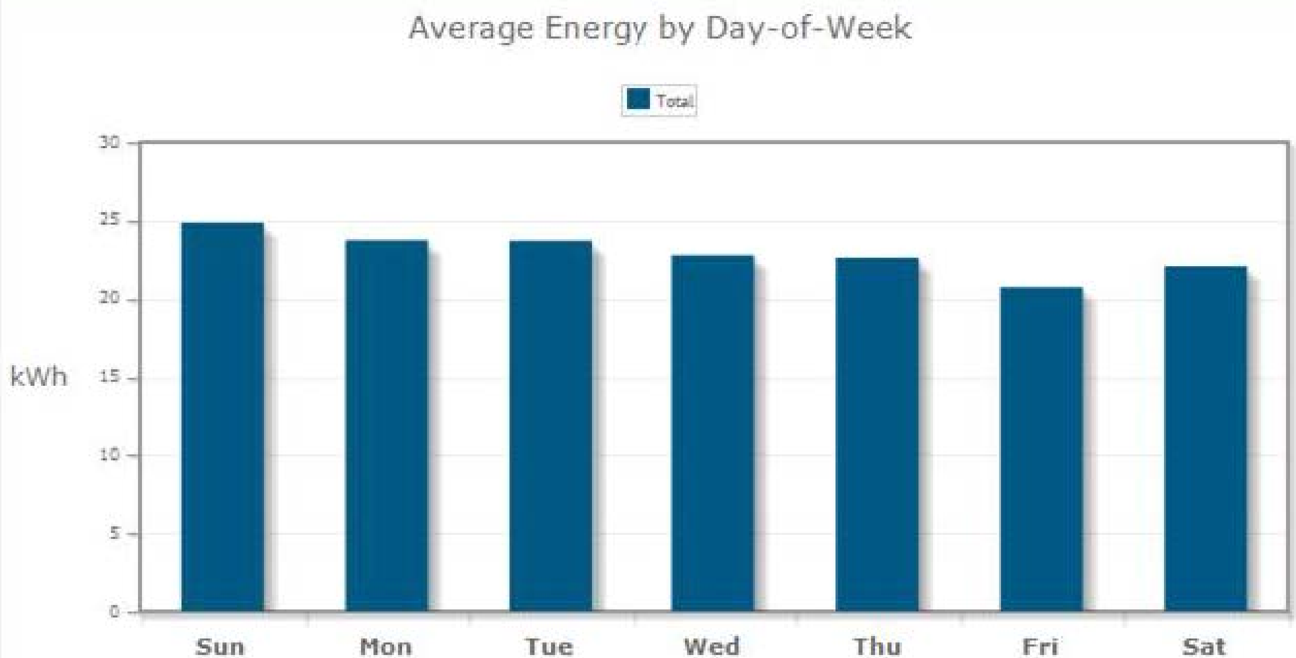
Daily Energy Usage

To change Meter, Graph, or Date, make new selections from the options below.

Meter:

Graph: Average Energy by Day-of-Week **Date:** 08/04/2014

Period: Billing Cycle Month Export Data



Look for trends or irregularities. Are your weekdays pretty even or does one stand out? How about weekends?

Terms And Conditions

Duke Energy Indiana T&D Infrastructure Improvement Plan

AMI Business Case

AMI Cost Details

Costs ($MM)	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total Deployment	Total TDSIC Period	Total 20 Year
Capital										
Field Technology	*$14.8*	*$45.5*	*$48.5*	*$37.7*	*$0.2*	*$0.7*	*$0.7*	***$146.5***	***$148.2***	***$161.8***
Project Mgmt Office (PMO)	*$3.8*	*$5.0*	*$5.2*	*$5.4*	-	-	-	***$19.4***	***$19.4***	***19.4***
IT&T[1]	*$8.1*	*$0.4*	*$0.4*	*$0.4*	-	-	-	***$9.3***	***$9.3***	***$9.8***
Total Capital Costs	$26.7	$51.0	$54.1	$43.5	$0.2	$0.7	$0.7	**$175.3**	**$176.9**	**$191.0**
O&M										
Field Technology	*$0.2*	*$0.2*	*$0.2*	*$0.2*	*$0.2*	*$0.2*	*$0.2*	***$0.8***	***$1.3***	***$4.4***
Project Mgmt Office (PMO)	*<$0.1*	-	-	-	-	-	-	***<$0.1***	***<$0.1***	***<$0.1***
IT&T[1]	*$0.3*	*$0.4*	*$0.5*	*$0.6*	*$0.6*	*$0.6*	*$0.6*	***$1.8***	***$3.7***	***$14.2***
Other	*$0.4*	*$0.9*	*$0.9*	*$0.9*	*$0.9*	*$0.9*	*$0.9*	***$3.1***	***$5.9***	***$20.2***
Total O&M Costs	$0.9	$1.5	$1.6	$1.7	$1.7	$1.7	$1.8	**$5.7**	**$10.9**	**$38.9**
Total AMI Costs	**$27.6**	**$52.5**	**$55.7**	**$45.3**	**$1.8**	**$2.5**	**$2.5**	**$181.0**	**$187.9**	**$229.9**

[1] IT&T - Information Technology & Telecommunications

Duke Energy Indiana T&D Infrastructure Improvement Plan

AMI Business Case

AMI Benefit Details

Benefits ($MM)	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total Deployment	Total TDSIC Period	Total 20 Year
Reduced Equip. Failures	*$0.9*	*$0.9*	*$0.9*	*$1.0*	*$1.0*	*$1.0*	*$1.0*	***$3.8***	***$6.7***	***$21.1***
Misc. Capital Savings	-	*$1.0*	*$1.0*	*$1.0*	*$1.0*	*$1.0*	*$1.0*	***$0.3***	***$0.6***	***$1.9***
Avoided Capital Costs	$0.9	$1.0	$1.0	$1.1	$1.1	$1.1	$1.1	**$4.1**	**$7.3**	**$23.0**
Reduced Meter Reading Cost	-	*$0.7*	*$2.5*	*$4.6*	*$6.2*	*$6.4*	*$6.6*	***$7.8***	***$26.9***	***$127.7***
Reduced COW[1] Costs	-	*$0.7*	*$2.5*	*$4.6*	*$6.2*	*$6.4*	*$6.6*	***$7.8***	***$27.0***	***$128.1***
Reduced Restoration Cost	-	*<$0.1*	*<$0.1*	*<$0.1*	*<$0.1*	*<$0.1*	*<$0.1*	***<$0.1***	***$0.3***	***$1.1***
Misc. O&M Savings	-	*$0.4*	*$0.4*	*$0.4*	*$0.4*	*$0.4*	*$0.4*	***$1.2***	***$2.4***	***$7.6***
Expense Reduction	-	$1.7	$5.4	$9.7	$12.8	$13.3	$13.7	**$16.8**	**$56.6**	**$264.5**
Reduce Theft, Equip Fail, Inst. Errors	-	*$1.8*	*$6.8*	*$12.1*	*$15.9*	*$16.1*	*$16.2*	***$20.7***	***$68.9***	***$287.2***
Improved Rev. Capture	-	$1.8	$6.8	$12.1	$15.9	$16.1	$16.2	**$20.7**	**$68.9**	**$287.2**
Total AMI Benefits	**$0.9**	**$4.5**	**$13.2**	**$22.8**	**$29.8**	**$30.5**	**$31.0**	**$41.5**	**$132.8**	**$574.7**

[1] COW - Consumer Order Worker (meter orders)

Key Financials	
Investment Period	20 Years
Net Present Value (NPV)	$37.9M
Payback Period	10.4 Years
Benefit / Cost Ratio (20 yr)	2.50

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

FILED

July 26, 2017

INDIANA UTILITY

REGULATORY COMMISSION

PETITION OF INDIANA MICHIGAN POWER COMPANY, AN INDIANA CORPORATION, FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN RATE ADJUSTMENT; (2) APPROVAL OF: REVISED DEPRECIATION RATES; ACCOUNTING RELIEF; INCLUSION IN BASIC RATES AND CHARGES OF QUALIFIED POLLUTION CONTROL PROPERTY, CLEAN ENERGY PROJECTS AND COST OF BRINGING I&M'S SYSTEM TO ITS PRESENT STATE OF EFFICIENCY; RATE ADJUSTMENT MECHANISM PROPOSALS; COST DEFERRALS; MAJOR STORM DAMAGE RESTORATION RESERVE AND DISTRIBUTION VEGETATION MANAGEMENT PROGRAM RESERVE; AND AMORTIZATIONS; AND (3) FOR APPROVAL OF NEW SCHEDULES OF RATES, RULES AND REGULATIONS.	)	CAUSE NO. 44967-NONE

SUBMISSION OF DIRECT TESTIMONY OF
<u>AARON L. HILL</u>

Petitioner, Indiana Michigan Power Company (I&M), by counsel, respectfully submits the direct testimony and attachments of Aaron L. Hill in this Cause.

Teresa Morton Nyhart (Atty. No. 14044-49)
Nicholas K. Kile (Atty. No. 15023-23)
Jeffrey M. Peabody (Atty No. 28000-53)
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Attorneys for Indiana Michigan Power Company

CERTIFICATE OF SERVICE

The undersigned certifies that the foregoing was served upon the following via electronic email, hand delivery or First Class, or United States Mail, postage prepaid this 26th day of July, 2017 to:

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Attorneys for INDIANA MICHIGAN POWER COMPANY

I&M Exhibit: _____

INDIANA MICHIGAN POWER COMPANY

PRE-FILED VERIFIED DIRECT TESTIMONY

OF

AARON L. HILL

INDEX

PRE-FILED VERIFIED DIRECT TESTIMONY OF AARON L. HILL
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

Q. Please state your name and business address.

A. My name is Aaron L. Hill. My business address is One Riverside Plaza, Columbus, Ohio 43215.

Q. By whom are you employed and in what capacity?

A. I am the Director of Trusts and Investments for American Electric Power Service Corporation (AEPSC).

Q. Please briefly describe your educational background and professional experience.

A. I received a Master's of Business Administration in Finance from the Ohio State University in 2009, where I was named a Weidler Scholar. I received a Bachelor of Science Degree in Civil Engineering from the United States Military Academy at West Point in 2001. I hold the Chartered Financial Analyst (CFA) designation.

Prior to joining AEP, I served approximately six years as a U.S. Army Officer in various combat engineering and project management positions. I began my career with AEP in 2009 as an Associate in AEP's Commercial Operations business unit. In 2011, I was hired into AEP's Strategic Initiatives group. Our department supported strategic projects and provided financial expertise to support business development and transaction efforts on a company-wide basis. In April 2016 I was named to my current position in Trusts and Investments.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to make a recommendation on the annual provision for nuclear decommissioning expense and support the forecasted prepaid pension asset. In this testimony, I show that the current level for decommissioning funding of $4.0 million for the Indiana jurisdiction is adequate for expected decommissioning costs. I recommend maintaining the current level of decommissioning funding. I discuss the estimation of future decommissioning costs, the rules and guidelines for determining adequate funding levels, and a methodology for determining an appropriate funding level. I recommend that there is no current need to resume funding for the Pre-April 7, 1983 spent nuclear fuel disposal fund. Finally, I discuss and support I&M's forecasted prepaid pension asset including Rate Base Adjustment 12 related to the prepaid pension asset.

Q. Are you sponsoring any exhibits in this proceeding?

A. I sponsor Rate Base Adjustment No. 12 on I&M Exhibit A-6.

Q. Are you sponsoring any attachments in this proceeding?

A. I sponsor Attachment ALH-1: Summary of Decommissioning Liability.

Q. Are you sponsoring any workpapers in this proceeding?

A. I am submitting the following workpapers:

- WP-ALH-1: Nuclear Decommissioning Cost Escalation Rates, Fuel and Energy Escalation
- WP-ALH-2: Nuclear Decommissioning Cost Escalation Rates, Labor Escalation
- WP-ALH-3: Nuclear Decommissioning Cost Escalation Rates, Barnwell South Carolina Disposal Site, Historical Burial Cost for Radioactive Wastes

- WP-ALH-4: Expected Return on Assets
- WP-ALH-5: Historical Annual Investment Returns
- WP-ALH-6: Nuclear Decommissioning Trust Beginning Balances As Of December 31, 2016
- WP-ALH-7: Pre-April 7, 1983 Spent Nuclear Fuel Disposal Market Value of Trust Assets
- WP-ALH-8: Pre-April 7, 1983 Spent Nuclear Fuel Disposal, Indiana Spent Fuel Asset Growth
- WP-ALH-9: Pre-April 7, 1983 Spent Nuclear Fuel Disposal, Indiana Spent Fuel Liability Amount
- WP-ALH-10: Prepaid Pension Benefits Balance
- WP-ALH-11: Qualified Pension Cost and Contributions Forecast

Q. Were the exhibits, attachments, and workpapers that you are supporting prepared by you or under your direction?

A. Yes.

NUCLEAR DECOMMISSIONING TRUST

Q. What is the purpose of the decommissioning trust?

A. The purpose of the external decommissioning trust is to ensure that adequate funds are available to pay for the safe dismantlement of the Cook Plant and related facilities, disposal of the radioactive portions of the plant, storage of spent nuclear fuel as needed, and restoration of the plant site. The external decommissioning trust is also needed to comply with certain State and Nuclear Regulatory Commission (NRC) requirements.

Q. What is the purpose of annual funding of the decommissioning trust?

A. Making regular, periodic contributions to fund the decommissioning trust helps provide funds for the future cost of decommissioning the nuclear power plant by customers who are receiving the benefits of its electric power generation during the plant's useful life. Failure to make sufficient contributions to the trust may cause the trust to violate Nuclear Regulatory Commission requirements. A lack of sufficient contributions could also result in funding decommissioning costs for the plant from future generations who may not receive electric power from the plant.

Q. How will the decommissioning trust be used?

A. At the end of the plant's life, the contributions and investment earnings built up in the trust will be used to pay for the expense of safely dismantling the plant, disposing of the irradiated portions of the plant and restoring the plant site to its original condition. In addition, any taxes due on the trust fund's investments will be paid.

Q. How can the appropriate amount of contributions to the decommissioning trust fund be determined?

A. Unit 1 of the Cook Nuclear Plant is scheduled to be retired in 2034, and Unit 2 of the plant is scheduled to be retired in 2037. Given that the plant is expected to run for another eighteen years and that the decommissioning process will last many more years after the plant is retired, determining the amount of current contributions needed to fully provide for decommissioning requires several assumptions. My testimony and work papers detail the assumptions I have made and the techniques used to reasonably estimate the necessary contributions. The steps can be briefly summarized as estimating the current cost for decommissioning the plant, projecting those costs to the time of the plant's retirement, projecting the after-tax value of the decommissioning trust fund, and evaluating the probability of whether or not the contributions were sufficient to fully fund decommissioning costs.

Q. What amount was recognized in the cost of service in I&M's last rate case for the funding of the Cook Plant's decommissioning costs?

A. The Commission most recently reviewed the Cook Plant's decommissioning costs in a comprehensive rate proceeding in Cause No. 44075. In the February 13, 2013 Order for that Cause, the Commission approved decommissioning costs of $4.0 million per year in the cost of service (divided evenly between Units 1 and 2 of the plant). As will be shown in this testimony, that amount is adequate for the revenue requirements for this case given the updated estimates in the recent decommissioning cost study from Knight Cost Engineering Services (CES).

Q. What is the basis for your conclusion regarding the level of the nuclear decommissioning costs to be included in the Company's cost of service?

A. I began with the decommissioning cost estimates from the January 2016 decommissioning study from Knight CES. I projected those costs using escalation rates I developed from authoritative data sources identified in my work papers and later in this testimony. Next, I used a Monte Carlo simulation technique to determine the probability of whether the current contribution rates would provide sufficient funds to decommission the plant. The results show that the current level of $4.0 million for the annual decommissioning trust contribution in the Indiana jurisdiction is adequate for satisfying the expected future decommissioning obligation. The details of my analysis will be discussed later in this testimony.

Q. Are there specific guidelines for the establishment and funding of decommissioning trusts related to nuclear power plants such as the Cook Plant?

A. Yes, the NRC has established guidelines to ensure the adequacy of funds for the safe dismantlement, decontamination and disposal of generating units at the end of their useful lives. These guidelines apply to both the amounts of fund contributions and the methods for funding the ultimate decommissioning of the units.

Q. What are the guidelines from the NRC regarding funding of nuclear decommissioning trusts?

A. The NRC requirements are detailed in 10 Code of Federal Regulations (CFR) §50.75. The requirements are intended to provide reasonable assurance that adequate funds will be available for the decommissioning process. To accomplish this, the NRC regulations require that the decommissioning fund assets should be held in an account segregated from the company, that the account must be outside the administrative control of the company owning the trust fund, and licensees inform the NRC of any material changes to the trust agreement. Further, the regulations specify a minimum amount to be accumulated in the fund for the radiological portion of the decommissioning. The regulations also require that each licensee of a nuclear power plant must prepare a biennial certification of assurance demonstrating that the licensee has accumulated at least a minimum amount of decommissioning funds. The regulations lay out the minimum amounts required for radiological decommissioning of reactors of different sizes and types in 1986 dollars. The regulations also specify how the decommissioning costs should be escalated.

Q. How were the current decommissioning costs estimated for the Cook Plant?

A. A detailed study of the decommissioning was performed by Knight CES. The results of that study are contained in a report, entered into these proceedings by witness Roderick Knight. The study assumed the use of the most current available technology to dismantle the plant and safely dispose of the irradiated portions of the plant waste.

Q. What is the estimated decommissioning cost for the Cook Plant from the Knight CES Study?

A. The decommissioning, fuel storage and greenfield costs for the plant were estimated to total $1.63 billion in 2015 dollars, as shown in Attachment ALH-1. The decommissioning expenditures for Unit 1 are scheduled to begin in 2034 and the decommissioning expenditures for Unit 2 are scheduled to begin in 2037, which are the end of the NRC operating license lives. Complete decommissioning of the plant is expected to take many years. In addition, ongoing costs for spent nuclear fuel storage are expected to continue indefinitely.

Q. How did you use the costs from the decommissioning study to develop the proposed funding levels?

A. The costs from the Knight CES study are expressed in 2015 dollars. Those costs are then projected to the time of decommissioning in order to assess the sufficiency of the level of decommissioning contributions. The decommissioning expenditures were escalated from their 2015 base level using the formula prescribed by the NRC for development of escalation rates for nuclear decommissioning costs. The NRC formula breaks the decommissioning costs into three components: labor, energy, and radioactive waste burial. The weight of each component is based on the detailed estimates in the Knight CES study. The weighted annual inflation of all components comprises the total cost escalation for decommissioning. The purpose of escalating decommissioning costs is to ensure that cost forecasts account for the rate in which decommissioning costs are expected to increase over the long time horizon between now and the completion of the decommissioning process. As described in detail later in my testimony, the decommissioning cost escalation for the Cook Plant from 2015 to the expected end of the plant's life was based on historical updates of inflation components from the Bureau of Labor Statistics and recent estimates of waste disposal costs published by the NRC.

DETAILS OF I&M'S DECOMMISSIONING TRUST

Q. Are the decommissioning fund assets held in an account external to the Company as required by the Nuclear Regulatory Commission?

A. Yes, the assets for I&M's nuclear decommissioning funds are held in a trust fund by The Bank of New York Mellon (BNY Mellon). BNY Mellon maintains separate accounting records for each unit and each jurisdiction of the Cook Plant decommissioning trust.

Q. Are the trust fund investments maintained outside of the administrative control of I&M?

A. Yes, the investment decisions for the trust fund are made by an independent investment manager, NISA Investment Advisors, L.L.C. (NISA). NISA, based in St. Louis, Missouri, was selected based on their performance and experience in managing both equity and fixed income investments in nuclear decommissioning trusts.

Q. What are the total assets in the Cook Plant nuclear decommissioning trust and how much is jurisdictional to Indiana?

A. At the end of 2016, the market value of assets in the decommissioning trust totaled $1,945,738,907. Those assets will have taxes due on investment gains when the investments are sold. At the current decommissioning trust tax rate of 20%, my estimate is that the taxes would total $141,622,262, leaving $1,804,116,646 in net assets available to pay decommissioning expenses (known as the liquidation value).

For the Indiana jurisdiction, the total market value at the end of 2016 was $1,390,697,559, and estimated taxes on unrealized gains would be $103,277,748, leaving a liquidation value of $1,287,419,810. To estimate the accumulation of the Indiana jurisdiction's liquidation value through the final date of decommissioning, contributions of $4.0 million and pre-tax investment earnings of 7.1% annually were assumed.

At December 31, 2018, the market value of assets available for the Indiana jurisdictional portion of the liability is projected to be $1,602,477,933, with taxes due of $144,033,823, resulting in a net liquidation value of $1,458,444,110.

Q. Are the assets in the Cook Plant nuclear decommissioning trust above the minimum amount required by the NRC?

A. No, at the end of 2016, the balance in the I&M decommissioning trust was below the NRC minimum. The NRC has specified that only the portion of the decommissioning trust allocated for radiological decommissioning can be used to fulfill the minimum requirements. By comparing the estimated radiological decommissioning costs to the total estimated costs in the Knight Decommissioning study, the portion of the Cook decommissioning fund applicable to the NRC minimum is 54.3% of the fund. Therefore, the current balance of the fund is short of the required amount by a total of $102,062,109.

The NRC specifications do allow a projection of the current balance to the time of decommissioning with the assumption that the assets will continue to grow from future contributions and an investment return above inflation. Including those assumptions for future growth allows the Cook Plant to meet the minimum funding requirements.

The NRC minimum requirements are a base level of funding necessary just to assure the safe dismantlement and disposal of the irradiated components of the plant, but not the dismantlement of the plant buildings and non-radioactive portions of the plant. I&M has a commitment to restore the plant site to a greenfield condition; i.e., the plant site should be restored to a condition comparable to that prior to the construction of the plant. Other NRC requirements in 10 CFR 50.54(bb) cover the storage cost for spent nuclear fuel. Those costs will be required until the Department of Energy (DOE) takes possession of spent fuel and are in addition to the amounts needed to meet the NRC minimum for radiological decommissioning.

DETAILS OF DECOMMISSIONING EXPENSE MODELING

Q. Is a comparison of the current estimate of decommissioning cost to the current balances in the decommissioning trust fund a valid method to evaluate the need for continued contributions to the trust fund?

A. No, it is not. Comparing current decommissioning cost estimates with current asset balances would be valid only if the plant were to be decommissioned immediately. In the case of the Cook plant, the decommissioning will not begin for nearly two decades. To evaluate the prospects for adequately providing for decommissioning the plant, both the expected cost of decommissioning the plant and the value of the funds that will be used to pay for it need to be extended through the entire decommissioning process.

The expected costs of decommissioning the plant have grown steadily and are expected to grow continuously in the future. In the modeling process I describe in detail below, an analytical process was used to estimate the expected future costs of decommissioning. The process examines the expected rate of inflation for the different cost components of decommissioning. The process then uses the cost components to produce a range of likely decommissioning costs that are extended over the time horizon needed to safely decommission the plant.

Although the decommissioning costs are expected to grow steadily, the decommissioning trust fund assets can only be expected to grow erratically, and, at times, may have periods of negative growth. The investment markets have a considerable amount of volatility. That volatility adds uncertainty to the amount of assets that will be accumulated over time, and makes forecasting the adequacy of funding the decommissioning trust a more complicated problem. Continued contributions at an adequate level helps assure the sufficiency of the amount of assets that will ultimately be available for decommissioning, and reduces the probability of a funding failure.

For these reasons, it is clear that a static comparison of the current assets in the trust to the currently estimated decommissioning cost is an overly simplistic method of analysis and could lead to erroneous conclusions about the need for continued funding for decommissioning expense.

Q. How is the annual funding requirement for decommissioning calculated?

A. To calculate the funding requirements, the individual component amounts of the decommissioning costs taken from the cash flow tables shown in Appendix C of the Knight CES Study were escalated at rates appropriate for each component. The total of those escalated component costs were then used as the future decommissioning expenses. The current balances of the decommissioning trusts (less the taxes that will be due on current capital gains when the investments are sold) were then used as the beginning point for the amount of assets available to pay for the decommissioning expenses. The projected balances, plus an assumed amount of annual future funding, were escalated at a range of after-tax rates of investment return through a Monte Carlo simulation process to determine the likelihood of having sufficient assets available at the end of the plant's useful life to pay for the decommissioning expenses.

Q. How was the decommissioning cost escalation rate calculated?

A. The escalation rate is a combination of several components, and was calculated for each year in accordance with NRC requirements. Separate forecasts were made for each of the formula's component pieces: the forecasted costs of labor, the rate of increase for energy costs, and the cost of radioactive waste disposal. Costs not included in those specific categories were escalated at the general rate of inflation. The components were then weighted according to the detailed estimates from the Knight CES Study. The weighted rates were then summed to determine the annual escalation rate for the cost to decommission the Cook Plant.

Q. How were the forecasts for labor and energy costs developed?

A. The forecast data for labor and energy costs came from historical information of the Bureau of Labor Statistics. For the labor cost component, the historical increases in compensation for the Midwest region were compared to the Consumer Price Index. Statistics dating back to the 1983 inception of the Midwest regional labor index shows that, on average, the increase in compensation exceeds the base rate of inflation by approximately 0.55%.

The energy cost component has two sub-components: Electricity and Fuel. For the escalation of the Electricity sub-component, the Electric Power Index was used and for the Fuel sub-component, the Petroleum Price Index was used. The indexes for these two cost components were compared to the rate of inflation extending back to the inception of the Electric Power Index in 1958. Consistent with the NRC formula and guidance, the composite energy factor was then calculated by using a 58% weighting for the electricity component and a 42% weighting for the fuel component. While the rate of increase for the labor cost index and the electric power price index have been relatively stable compared to the general rate of inflation for the past few years, the fuel price index has fluctuated dramatically. The weighted average for the combined cost of energy was calculated to have historically increased by 1.17% in excess of the base rate of inflation.

Q. How was the escalation rate for waste disposal costs calculated?

A. The NRC periodically publishes a report on waste burial charges. The report, called *NUREG 1307 Report on Waste Burial Charges*, gives current estimates of waste disposal costs for decommissioning of nuclear power plants. Historical data is also provided in the report, allowing a trend line for costs to be estimated. The most recent version of the report, NUREG-1307 Revision 16, was released in March 2017.

There are very few waste burial sites available for use by the Cook Plant. One site currently available for disposal of low-level waste from the Cook Plant is located in Clive, Utah, and is run by a private company named EnergySolutions. The EnergySolutions site can take the lowest level of radioactive wastes, but it would not be able to accept the more highly radioactive debris. Accordingly, the Knight CES study assumes that the EnergySolutions site would be used for the lowest-class waste to be disposed of from the Cook Plant. However, since there is no publicly available information for the EnergySolutions site, costs from it cannot be used to estimate an escalation factor for future increases in the waste disposal expense.

The study also assumes that portions of the reactor building will be removed and sent to a processing facility owned by the Swedish firm Studsvik near Memphis, Tennessee.

A new radioactive waste disposal facility has opened near Andrews, Texas. The Knight CES study assumed that the Texas site will be used for the burial of higher-level Class B and C radioactive waste. However, since the site is new, there is not yet a history of publicly available waste disposal costs from which to estimate a trend line, so it also cannot be used to estimate an escalation factor for waste disposal costs.

The radioactive waste burial site in Barnwell, South Carolina has been used in previous decommissioning cost studies for the Cook Plant. However, that site was closed in 2008 to most waste generators, including the Cook Plant. So, although the Barnwell site cannot be used in the decommissioning plan for the Cook plant, the publicly available history of costs for the use of that site give an indication of the pattern of cost increases that can be expected for similar sites, including the Texas facility. For that reason, the disposal costs at the Barnwell, South Carolina site were used to estimate the escalation factor for nuclear waste disposal.

Although historical waste disposal cost data for the Barnwell site is available for more than 25 years, changes in regulations resulted in a high rate of increase in waste burial costs in the 1990's. More recent data better reflects current conditions, and is more useful for establishing a trend for future cost increases.

Over the past 17 years, the cost of waste burial has increased by an average of 2.06% more than the base rate of inflation.

Q. How were the cost components escalated?

A. The three major cost components (labor, energy and waste disposal) were escalated based on their correlation with the inflation rate. For purposes of modeling, a triangular distribution was assumed for the rate of inflation, with the values centered on 2.5%, and values allowed to vary between 2.0% and 3.0%. This set of rates was chosen to represent a sample of rates in line with the recent general rate of inflation. This method produces trials with most values of CPI near 2.5% and a lower number of trials with CPI near the boundaries of 2.0% and 3.0%. Of course, future inflation may be higher or lower than the assumed rates.

Q. What asset classes for investments were used in developing estimates of investment returns?

A. The major asset classes used were the broad categories of domestic equities, fixed income, and cash. Each of these asset classes has a long history which can be used to evaluate return potential, risks, and correlations with the other classes. The average rates of return used for the asset classes reflect the long term outlook, and are based on the rates used for setting the rate of return expectations for the AEP pension fund. The rates for equities and cash were not adjusted for investment restrictions in the decommissioning trust funds.

Q. What is the impact of taxes on the investment portfolio?

A. The trust fund must pay taxes on the investment income and any investment gains that are realized in the portfolio. The taxes paid detract from the growth of the trust fund, and reduce the amount of funds that will ultimately be available to pay for decommissioning expenses. Currently, the tax rate on the qualified trust fund is 20%.

Q. How will the asset allocation of the decommissioning trust investment portfolio change over the life of the trust fund?

A. The allocation will be changed as the planned date for decommissioning the plant draws near to reduce the amount of investment risk in the portfolio and to provide sufficient liquid assets to pay for decommissioning costs. The current allocation is appropriate for the long-term growth of the fund. However, as decommissioning draws closer, the investment portfolio will be shifted to reduce the potential for investment losses. Beginning about ten years prior to the retirement of the plant, the level of equities will be reduced and more fixed income securities will be held in the portfolio in order to reduce the level of equity market risk in the decommissioning trust fund. Although the reduction in the equity allocation will reduce the expected rate of return on the fund, prudent investment practice calls for a reduction of risk when there is less time available to recover from a potential market loss before the funds are needed for decommissioning. The projected changes in asset allocation were included in the modeling.

Q. How were the projected costs of decommissioning the plant allocated between I&M's retail jurisdictions?

A. In order to determine the net decommission cost responsibility for I&M's retail jurisdictions it is necessary to first reduce the total decommissioning cost estimate by an estimate of the total contributions from I&M's wholesale customers. This initial step is further explained by Company witness Williamson. The remaining balance of decommissioning cost responsibility is then allocated to I&M's Indiana and Michigan retail jurisdictions using the demand allocation factors determined by Company witness Stegall. Indiana's portion of the remaining decommissioning obligation amounts to 81.89% of the total decommissioning cost.

Q. How were the decommissioning projections accomplished?

A. As in previous cases, a Monte Carlo simulation was used to project both the trust fund and decommissioning costs. Monte Carlo simulation is a problem solving technique utilized to approximate the probability of certain outcomes by performing multiple trial runs, called simulations.

Q. Why is a Monte Carlo simulation useful in modeling the nuclear decommissioning funding requirements?

A. Monte Carlo simulation is a useful method to create a set of possible results for situations in which the inputs are uncertain. In the case of the decommissioning funds, the investment returns and the base cost inflation rate are the uncertain variables. The output of the Monte Carlo model is a set of probabilities that there will be sufficient funds available to successfully achieve the decommissioning goal. In this case, it is useful in determining the funding requirements for the nuclear decommissioning trust fund since it can be used to simulate a range of possible investment returns for the fund in the future. Although it is impossible to know in advance what the actual rate of return the trust fund's investments will be over the life of the plant and the subsequent decommissioning, an estimate of the possible ranges of annual returns can be constructed. The Monte Carlo simulation generates a large number of possible outcomes for the decommissioning fund by varying the annual rate of return on the fund's investments. In doing so, it can help estimate the probability of meeting the goal of having enough assets to fully pay for decommissioning the plant. The probability of having sufficient funds at the time of the planned plant retirement available to fully decommission the plant was computed to determine the appropriateness of the current level of funding.

Q. What will be done with the spent nuclear fuel when the plant is retired?

A. In previous filings, I&M had assumed that the DOE would perform in accordance with its contract and would accept the spent nuclear fuel and remove it from the plant site. However, since funding for the national spent fuel repository has been canceled, it has become more likely that the spent fuel will remain at the plant site indefinitely. The 2016 Knight CES Decommissioning Study includes cost of storing the spent nuclear fuel at the plant site indefinitely. The fuel will be removed from the plant and transferred to an Independent Spent Fuel Storage Installation (ISFSI) at the plant site, where it can be secured and monitored.

When DOE failed to commence compliance with its contract, I&M pursued a law suit against DOE for damages. In 2011, I&M and DOE reached a settlement agreement, creating a process by which I&M submits annually its claim for damages, DOE reviews it, and the Government pays the amount agreed to out of the Judgment Fund (a U.S. Government account administered by the Department of Justice). Under this settlement process, I&M has been successful in the recovery of most of the storage costs for the spent nuclear fuel. However, the current settlement agreement with the DOE expires at the end of 2019. I&M believes that DOE will ultimately extend the settlement agreement that allows for recovery of costs associated for spent fuel storage, but cannot be certain of the timing or terms of such agreement. Alternately, I&M would hope to prevail if no agreement is reached and litigation proves necessary. However, neither path is certain nor provides reasonable assurance that funds would be available when needed to manage spent nuclear fuel. Additional details related to the recovery of costs from the DOE are contained within the testimony of Company witness Shane Lies.

For the projections performed for this testimony, I assume that, starting in 2034, the decommissioning fund will need to provide reasonable assurance that funding is available for managing spent nuclear fuel storage as required by 10 CFR 50.54(bb). The annual costs for the storage of the spent fuel that is in the reactor at the time of plant shut-down were escalated out to year 2100, effectively reflecting indefinite storage for accounting purposes. Storage costs for the spent nuclear fuel that had been used and removed from the reactor prior to shut-down are not included in the decommissioning cost estimate.

In addition to the costs for the storage of the final load of spent nuclear fuel, there will also be costs incurred to decommission the ISFSI when the spent fuel is finally removed, whether that occurs in 2100 or another date, from the plant site. Those costs are also included in the decommissioning cost estimates.

Q. What is the most significant risk for the decommissioning trust fund?

A. Although the risk of an investment loss is commonly associated with an investment portfolio, the greatest risk to the decommissioning trust is the possibility of a shortfall – not having sufficient assets to fully pay for the cost of decommissioning the plant. The investment risk can be managed and minimized by building and continuously monitoring a diversified portfolio. Since the investment markets have historically shown a tendency to increase in value over time, the long time horizons associated with the decommissioning trust fund also reduce the amount of investment risk.

In contrast, the risk of a shortfall in the fund is more difficult to manage, and would be more difficult to recover from. A shortfall would mean that the fund has failed to meet its basic objective of fully providing for the decommissioning of the plant. Since the decommissioning activities will continue for many years after the plant is removed from service, the existence of a shortfall and the extent of a shortfall may not be known for some time after the decommissioning process begins. Since annual contributions to the fund would have already ceased and since the investments would be positioned in a conservative asset allocation to accommodate payments for decommissioning expenses, the shortfall could not be eliminated with either extraordinary gains or normal annual contributions.

Q. What could cause the decommissioning fund assets to be less than anticipated?

A. The investment returns on the trust fund's assets will be affected by future investment markets. The investment markets are unpredictable, and the investment returns achieved may lag behind the returns projected. A slight decrease in the cumulative investment rate of return could cause a large shortfall in the funds available for decommissioning at the time the plant is retired. For example, a 1% decrease in the average investment rate of return on the qualified fund would cause an approximately $500 million decrease in the Indiana jurisdictional fund balance at the plant retirement date in 2034.

Q. Are there any other risk factors in planning for decommissioning?

A. Yes. Although I&M certainly intends to operate the plant until its planned retirement there still remains the possibility that the plant may be shut down prior to the expiration of the operating license. This possibility would have the effect of not allowing the decommissioning funds to grow for as long as is currently planned, and would increase the probability that the decommissioning funds available may be insufficient to pay for the decommissioning expenses. In recent years, several nuclear plants in the United States have shut down prior to the expiration of their licenses. Among those shut down prematurely are the Crystal River Unit 3 in Florida, San Onofre Units 2 and 3 in California, the Kewaunee plant in Wisconsin, and the Vermont Yankee plant.

Q. Is the current amount of funding adequate for the Cook Plant decommissioning?

A. The modeling results show that the current amount of annual decommissioning funding for the Indiana jurisdiction of $4.0 million should be adequate to safely decommission the plant at the end of its useful life. The probability of having sufficient funds at the current level of contributions is approximately 81%. Stated another way, there is approximately a one in five chance the trust fund will not have enough money at the end of the plant life to fully pay for decommissioning. I&M will continue to report to the Commission every three years on the adequacy of the existing provision, however, and it may recommend adjusting the level of decommissioning fund contributions needed in the future.

SPENT NUCLEAR FUEL TRUST

Q. What is the history of the funding for the disposal of spent nuclear fuel?

A. The Nuclear Waste Policy Act of 1982, signed into law on January 7, 1983, established that the Federal Government had responsibility to provide for the permanent disposal of spent nuclear fuel and the costs of such disposal were the responsibility of the generators and owners of the spent nuclear fuel. The DOE promulgated rules under this Act that relate, in part, to the disposal of spent nuclear fuel from commercial nuclear reactors including Cook Plant. In June 1983, I&M signed a contract with the DOE that provided, among other things, for payment of fees to the U.S. Treasury for such disposal. The contract consisted of fees derived by two cost mechanisms. One mechanism was a one-time fee for nuclear fuel spent to generate electricity at civilian nuclear power reactors prior to April 7, 1983

(Pre-April 7, 1983). The second mechanism was a fee per kilowatt-hour of generation for spent nuclear fuel resulting from the generation and sale of electricity on or after April 7, 1983 (Post April 6, 1983).

So, in addition to the liability for decommissioning the nuclear plant, I&M also has an obligation to the DOE to pay for the disposal of spent nuclear fuel used prior to April 7, 1983. The obligation is a fixed amount that increases with interest accumulated each year.

Amounts included in the fuel cost adjustment mechanism for the Post-April 6, 1983 spent nuclear fuel disposal costs are required to be deposited quarterly with the U.S. Treasury. Starting in June 2014, the DOE concluded that appropriate quarterly payment is zero until a viable spent fuel disposal program is progressing. These collections will continue at the present zero level unless the U.S. Government either funds and executes the current program or revises the statutes to start up an alternate, viable program. Those amounts do not directly affect decommissioning.

Q. How much is the liability for disposal of Pre-April 7, 1983 spent nuclear fuel?

A. On a total Company basis, the initial liability for Pre-April 7, 1983 spent nuclear fuel disposal was $71,963,830. The liability increases each quarter based on the most current yield for 3-month Treasury bills. It has increased through the accumulation of interest to $266,268,432 as of December 31, 2016, and, based on the current Treasury bill rate, is projected to increase only slightly by December 31, 2017 to about $267,107,178. The portion of the liability allocated to Indiana, after applying assets accumulated from wholesale customers, was approximately

$182,055,685 at December 31, 2016, and it should grow to about $183,056,253 by December 31, 2018 as shown in WP-ALH-9.

Q. Please describe the Pre-April 7, 1983 spent nuclear fuel disposal trust fund.

A. Like the nuclear decommissioning trust, the spent nuclear fuel trust fund is held at BNY Mellon. The fund is considered to be a non-qualified fund, and, as such, contributions to it are not tax deductible and investment income and capital gains are subject to corporate income taxes.

Q. What is the value of the assets in the trust fund for the Pre-April 7, 1983 spent nuclear fuel disposal liability?

A. As of December 31, 2016, the Indiana jurisdictional portion of I&M's spent nuclear fuel trust fund had a market value of $219,600,285. That balance is expected to increase to about $221,890,066 by December 31, 2018 as shown in WP-ALH-8. The Indiana jurisdictional balance of the spent nuclear fuel trust fund is currently greater than the spent fuel liability allocated to it, and is projected to remain so for the projected test year. As such, the trust may be considered fully funded at this time and for the duration of the projected test year.

It is important to note that the spent nuclear fuel liability will continue to increase through the accrual of additional interest until paid. Furthermore, the liability can move from fully funded to less than fully funded through changes in the market value of trust fund securities, differences between the liability accretion rate and the investment earnings rate and other factors.

Q What are your recommendations for the funding of the spent nuclear fuel liability?

A. The spent nuclear fuel trust is adequately funded at the present time. As the current level of assets exceeds the liability and both are growing very slowly, the fund does not appear to be in danger of becoming under-funded in the near future. For those reasons, additional funding is not necessary at this time. I recommend that the funding for the Pre-April 7, 1983 spent nuclear fuel disposal remain suspended.

It should be noted that the obligation to the DOE has not yet been satisfied, and that the need for funding of the spent nuclear fuel disposal trust will be evaluated periodically. If additional funding is needed in the future, I&M will make a recommendation at that time.

PRE-PAID PENSION ASSET

Q. Has I&M included a prepaid pension asset in this case?

A. Yes. Consistent with the Order in IURC Cause No. 44075, I&M seeks to continue the inclusion of Prepaid Pensions in I&M's rate base. The order in Cause No. 44075 stated that the prepaid pension asset was recorded on the Company's books in accordance with governing accounting standards, the prepaid pension asset reduced the pension cost reflected in the revenue requirement in the case, preserves the integrity of the pension fund, and should be included in rate base. Company witness Williamson further supports this ratemaking treatment.

Q. Please describe I&M's ongoing funding strategy for the employee pension plan.

A. I&M's strategy is to fund at least the annual minimum amount required by the Employee Retirement Income Security Act of 1974 (ERISA). Additional discretionary contributions may be made to maintain the funded status of the plan.

Q. Please define a prepaid pension asset?

A. A prepaid pension asset can be defined as cumulative pension cash contributions less cumulative pension cost.

Q. What is the value of the prepaid pension asset included in I&M's rate base?

A. The value of the prepaid pension asset is projected to be $104,345,881 on December 31, 2018, I&M's test year end.

Q. Please describe the process of forecasting the prepaid pension asset?

A. The prepaid pension asset is forecasted similar to other asset balances, beginning with an actual balance as of a period end and adjusting for forecasted activity. The value of the prepaid pension asset was $102,492,883 as of December 31, 2016. Forecasted pension cash contributions of $13,708,000 and $12,895,000 for years 2017 and 2018 respectively, are added to the December 31, 2016 prepaid pension asset balance. Forecasted pension costs of $14,009,000 and $10,741,000 for years 2017 and 2018 respectively, are subtracted. The result is the projected December 31, 2018 prepaid pension asset balance.[1] Please see WP-ALH-10.

[1] These amounts are total Company and exclude the River Transportation Division.

Q. What process does I&M use to forecast pension contributions and costs?

A. I&M uses the services of a professional actuarial firm, Willis Towers Watson, to develop this forecast. I collaborate with them, along with internal AEP departments such as Accounting and Human Resources, to ensure the assumptions included in Willis Towers Watson's model are consistent with plan provisions, participant demographics, asset balances and other important data and plan characteristics. Please see WP-ALH-11.

Q. What is the purpose of Rate Base Adjustment No. 12 of Exhibit A-6?

A. Rate Base Adjustment No. 12 adjusts I&M's prepaid pension asset to the forecasted prepaid pension costs for 2017 and 2018.

SUMMARY

Q. What is your recommended level of funding for the Cook Plant nuclear decommissioning trust, Pre-April 7, 1983 spent nuclear fuel trust and prepaid pension asset treatment?

A. The current rate of funding of $4.0 million annually should be maintained. I believe that maintaining the current level of funding provides an adequate probability of having sufficient assets in the trust fund to safely decommission the plant.

The funding for the Pre-April 7, 1983 spent nuclear fuel disposal should remain suspended for the time being. I&M will continue to monitor the level of funding for nuclear decommissioning and for Pre-April 7, 1983 spent nuclear fuel disposal and will continue to report to the commission every three years, with this testimony and attachments serving as the report for the current three-year cycle.

The prepaid pension asset included in I&M's rate base and in adjustment RB 12 is accurate and appropriate.

Q. Does this conclude your pre-filed verified direct testimony?

A. Yes.

VERIFICATION

I, Aaron L. Hill, Director of Trusts and Investments for American Electric Power Service Corporation, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information, and belief.

Date: 7/20/2017

Aaron L. Hill

Attachment ALH-1

Cook Nuclear Plant
Summary of Decommissioning Liability
January 2016 Decommissioning Study
2015 Dollars

Decom Method	Spent Fuel Storage	Storage Site / Systems	Spent Fuel Repository Open	Base Decom Costs	Spent Fuel Storage Costs to 2098	ISFSI Decom	Total Decom. Costs to Year 2100 in 2015 Dollars	Indiana Jurisdictional Portion of Liability
DECON	Dry	On-Site	Never	$1,634,038,387	$ 270,198,500	$ 56,952,300	$ 1,961,189,187	$ 1,468,082,803