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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANA MICHIGAN POWER)
COMPANY ("I&M"), AN INDIANA CORPORATION,)
PURSUANT TO INDIANA CODE CHAPTER 8-1-8.8 AND)
8-1-2-23, 8-1-2-10, 8-1-2-12, 8-1-2-14, AND 8-1-2-42(a), AND)
5-14-3-4 AND 8-1-2-29, REQUESTING THAT THE)
COMMISSION: (1) FIND THAT I&M'S PROPOSED LIFE)
CYCLE MANAGEMENT PROJECT AT THE DONALD C.)
COOK NUCLEAR PLANT IS REASONABLE AND)
NECESSARY; (2) APPROVE THE ESTIMATED)
CONSTRUCTION COSTS AND SCHEDULE OF THE)
PROPOSED LIFE CYCLE MANAGEMENT PROJECT;)
(3) AUTHORIZE I&M TO RECOVER, ON A TIMELY)
BASIS VIA A PERIODIC RATE ADJUSTMENT)
MECHANISM, THE COSTS AND EXPENSES)
ASSOCIATED WITH THE LIFE CYCLE MANAGEMENT)
PROJECT (INCLUDING STUDY, ANALYSIS AND)
DEVELOPMENT COSTS, IN ADDITION TO)
CONSTRUCTION, FINANCING, AND OTHER COSTS);)
(4) GRANT I&M AUTHORITY TO DEFER SUCH COSTS)
ON AN INTERIM BASIS UNTIL SUCH COSTS ARE)
REFLECTED IN I&M'S RETAIL ELECTRIC RATES;)
AND (5) GRANT I&M SUCH FURTHER RELIEF AS)
MAY BE NECESSARY OR APPROPRIATE)

CAUSE NO. 44182

APPROVED: JUL 17 2013

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Loraine L. Seyfried, Chief Administrative Law Judge

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On April 13, 2012, Indiana Michigan Power Company (“I&M,” “Petitioner,” or “Company”) filed its Verified Petition with the Indiana Utility Regulatory Commission (“Commission”) initiating this Cause. In its petition, among other things, I&M requests the Commission review and approve as reasonable and necessary a proposed Life Cycle Management Project for its Donald C. Cook Nuclear Plant (“LCM Project” or “Project”), including estimated costs and a schedule for such Project, and find that the Project when completed will be used and useful in the provision of retail electric utility service to Petitioner’s Indiana customers. Petitioner also requests approval of certain ratemaking and accounting treatment for the LCM Project so as to allow for full and timely recovery of reasonable construction and operation costs associated with the LCM Project, as well as reasonable study, analysis and development costs incurred in connection with the LCM Project.

On April 16, 2012, Citizen’s Action Coalition (“CAC”) filed its Petition to Intervene, which was granted by the Presiding Officers on May 9, 2012. On June 1, 2012, the Indiana Michigan Power Industrial Group (“I&M IG”) filed its Petition to Intervene, which was granted on June 11, 2012.

Petitioner prefiled its direct testimony and exhibits on April 16, 2012. The Indiana Office of Utility Consumer Counselor (“OUCC”), I&M IG and CAC prefiled their direct testimony and exhibits on August 30, 2012. On October 1, 2012, Petitioner filed a Notice of Substitution of Witness and the prefiled testimony of that witness. The next day, on October 2, 2012, Petitioner prefiled its rebuttal testimony and exhibits. Pursuant to the Presiding Officers’ October 15, 2012 Docket Entry, the OUCC filed supplemental testimony on December 6, 2012 and Petitioner filed supplemental rebuttal testimony on December 20, 2012.

Pursuant to legal notice published in accordance with applicable law, the Commission commenced an evidentiary hearing on January 16, 2013, in Room 222 of the PNC Center, 101 W. Washington St., Indianapolis, Indiana. Petitioner, the OUCC, I&M IG and CAC appeared and participated. At the hearing, the parties’ respective evidence was offered and admitted into the record, and witnesses were cross-examined. No members of the general public participated at the evidentiary hearing.

Based on the evidence presented and the applicable law, the Commission finds as follows:

1. Notice and Commission Jurisdiction. Due, legal, and timely notice of all public hearings in this Cause was given and published as required by law. Proper and timely notice was given by Petitioner to its customers summarizing the nature and extent of the proposed changes in its rates and charges for electric service. Petitioner is a public utility as defined by Ind. Code § 8-1-2-1. Petitioner seeks approval of, and other relief associated with, its LCM Project pursuant to Ind. Code ch. 8-1-8.8, Ind. Code §§ 8-1-2-23, -42, -10, -12, -14, and Ind. Code §§ 5-14-3-4 and 8-1-2-29. Therefore, the Commission has jurisdiction over Petitioner and the subject matter of this Cause.

2. Petitioner's Characteristics and Business. I&M, a wholly owned subsidiary of American Electric Power Co., Inc. ("AEP"), is a corporation organized and existing under the laws of the State of Indiana, with its principal executive office at One Riverside Plaza, Columbus, Ohio 43215, and with its principal Indiana office at One Summit Square, P.O. Box 60, Fort Wayne, Indiana 46801. I&M is engaged in, among other things, rendering retail electric service to approximately 583,000 customers within a service area covering approximately 8,260 square miles in northern and east central Indiana and southwestern Michigan. In Indiana, I&M provides retail electric service to approximately 455,000 customers in the following counties: Adams, Allen, Blackford, DeKalb, Delaware, Elkhart, Grant, Henry, Huntington, Jay, LaPorte, Madison, Noble, Randolph, St. Joseph, Steuben, Tipton, Wabash, Wells, and Whitley. In Michigan, I&M currently provides retail electric service to approximately 128,000 customers. In addition, I&M serves customers at wholesale in both Indiana and Michigan.

I&M owns, operates, manages and controls plant and equipment within the states of Indiana and Michigan that are in service and used and useful in the generation, transmission, distribution and furnishing of such service to the public. I&M is a member of the PJM Interconnection, LLC ("PJM"), a regional transmission organization approved by the Federal Energy Regulatory Commission. Petitioner operates six coal-fired generating units, various other generating facilities and also owns and operates the Donald C. Cook Nuclear Plant ("Cook Plant" or "Plant"), a nuclear fueled, steam electric generating station, located in Bridgman, Michigan. Units 1 and 2 of the Cook Plant ("Cook Units" or "Units") are rated at approximately 1084 MW (net) and 1107 MW (net), respectively. Cook Units 1 and 2 were placed in service in 1975 and 1978, respectively, under forty-year Nuclear Regulatory Commission ("NRC") operating licenses received in 1974 and 1977, respectively. I&M first received operating license extensions in 1991 to cover the period between construction permit issuance and operating license issuance; and then, in 2005, I&M received additional license extensions from the NRC to allow Units 1 and 2 to operate until 2034 and 2037, respectively.

3. Relief Requested. In this proceeding, Petitioner requests the Commission review and approve as reasonable and necessary its LCM Project, including its estimated costs and schedule for such Project, and find that the Project when completed will be used and useful in the provision of retail electric utility service to Petitioner's Indiana customers. I&M's Petition explained that life cycle management for a nuclear power plant consists of the integration of aging management and economic planning to: (1) optimize the operation, maintenance, and service life of systems, structures and components; (2) maintain an acceptable level of performance and safety; and (3) maximize return on investment over the service life of the plant. Life cycle management is integrally related to the continued safe, reliable and economic operation and availability of the Cook Plant during its extended operation license lives. According to its Petition, I&M's LCM Project at its Cook Plant consists of a group of projects (referred to herein as "sub-projects") requiring significant capital investment (along with associated operating and maintenance expenses) intended to fulfill the extended operating licenses of Units 1 and 2 by: safely and reliably extending the operating lives of the Units consistent with their operating licenses (*i.e.*, until 2034 and 2037, respectively); increasing the safety and reliability of these Units; and also preserving the option for a potential future increase in the electric output of these Units through a potential future "capacity uprate."

By its Petition, Petitioner also requests the Commission approve certain ratemaking and accounting treatment for the LCM Project so as to allow for full and timely recovery of its reasonable construction and operation costs associated with the LCM Project, as well as reasonable study, analysis and development costs incurred in connection with the LCM Project. Specifically, Petitioner requests the Commission authorize it to: (a) recover on a timely basis its financing costs incurred during construction of the LCM Project, for all such sub-projects that are under construction on and after January 1, 2012; (b) recover on a timely basis its post-in-service financing costs, and incremental depreciation and property tax costs and expenses, associated with the LCM Project and incurred on and after January 1, 2012; and (c) recover on a timely basis its costs associated with the study, analysis, or development of the LCM Project; all via a periodic rate adjustment mechanism to commence upon approval by the Commission in this proceeding and to be updated every six months thereafter. Additionally, Petitioner requests that the Commission authorize it to defer, on an interim basis, post-in-service financing costs and certain operation and maintenance costs (specifically, incremental depreciation and property tax costs), along with study, analysis and development costs, until the applicable costs are included in Petitioner's retail electric rates. Petitioner also requests that the Commission authorize it to add earnings on its LCM Project to its authorized net operating income for earnings test purposes of the fuel adjustment charge ("FAC") statute (Ind. Code § 8-1-2-42(d)(3)). Petitioner also requests the Commission institute an ongoing review process for the construction of the LCM Project, similar to the processes contemplated by Ind. Code §§ 8-1-8.5-6 and 8-1-8.7-7, in order to achieve a more open and transparent public process with respect to the construction of the LCM Project.

Finally, Petitioner also requests the Commission grant confidential treatment, pursuant to Ind. Code §§ 8-1-2-29 and 5-14-3-4, for certain information filed in support of its request for relief.

4. Petitioner's Case-in-Chief Evidence.

A. Paul Chodak III, President and Chief Operating Officer of I&M. Mr. Chodak described the Cook Plant, its importance to I&M and its customers, the need for and cost-effectiveness of the LCM Project, and the importance of timely cost recovery of the Cook LCM Project costs. Mr. Chodak also discussed I&M's commitment to an open and transparent construction and ratemaking process for the LCM Project, including an ongoing Commission review procedure.

Mr. Chodak explained that Cook Units 1 and 2 were placed in service in 1975 and 1978, respectively, under forty-year NRC operating licenses obtained in 1974 and 1977 for the Units. I&M sought and received operating license extensions in 1991 to cover the period between construction permit issuance and operating license issuance; and then, in 2005, I&M received twenty-year license renewals from the NRC to allow Units 1 and 2 to operate until 2034 and 2037, respectively.

Mr. Chodak testified the Cook Units provide customers with a reliable source of capacity and energy, low-cost generation, and a reduced emissions footprint. According to Mr. Chodak,

the Cook Units are among the lowest production cost generation resources on the AEP system, supplying customers with over 2,100 MW of base load generation -- approximately 40% of the generating capacity, and 50% of energy output for I&M -- with nearly 80% of Cook's production supplied to Indiana customers (65% to retail Indiana customers). The Cook Plant generates about 50% of the power consumed by I&M's customers. Mr. Chodak emphasized the Cook Units are highly reliable, while also maintaining an excellent safety record. For example, Unit 1 achieved a capacity factor of 95.5% during its last operating cycle, and Unit 2 achieved a 100% capacity factor during its most recent operating cycle.

Mr. Chodak noted that the Cook Units do not emit carbon dioxide. Thus, in a potentially carbon-constrained world, I&M has a significant head start toward being able to keep its costs and rates lower than other utilities without nuclear plants.

Mr. Chodak stressed that the Cook Plant is integral to I&M's long term resource strategy. The twenty-year license renewals allow Cook to continue to make reliable, low-cost, emission-free generation available to I&M customers through 2034 (for Unit 1) and 2037 (for Unit 2). However, to ensure the Units maintain their reliability, I&M must make substantial capital investments in the equipment, systems, and facilities that make up the Cook Plant. The Company has performed extensive analyses of the systems and components that will require additional investment in order for the Cook Units to continue to operate for the extended license periods. The results of these analyses form the proposed LCM Project. Mr. Chodak emphasized the LCM Project is necessary to continue operation of the Cook Plant.

Mr. Chodak also discussed the benefits that will result from the LCM Project. In addition to the substantial benefits to customers associated with having the Cook Units available for an additional twenty years, the Project will effectively provide a hedge against continuing and future environmental requirements, produce employment benefits, and provide an additional 50 MWs of capacity resulting from efficiencies of new equipment.¹

Mr. Chodak testified that the estimated cost of the LCM Project is approximately \$1.169 billion.² Mr. Chodak also explained that alternatives to the LCM Project were much more costly. For example, replacing the Cook Units with new nuclear capacity would cost approximately \$6 billion to \$9 billion dollars per unit (about \$6,000 per kW). Mr. Chodak also explained that the cost of the LCM Project is over and above typical capital spending for the Cook Units. He observed that, due to the complexity, magnitude, and special nature surrounding the LCM Project, these costs are not ordinary capital expenditures. Mr. Chodak also noted that the Indiana Legislature, in Senate Bill 251 (codified in Ind. Code ch. 8-1-8.8), recognized that LCM costs are unique and deserving of special regulatory treatment.

¹ Mr. Carlson explained that, as a result of the technological evolution of steam turbine design over the last 30 years, newer models can now be installed which are more efficient at converting the energy in steam to mechanical power. The proposed turbine replacement will incidentally result in the addition of 50-60 MW to the nameplate capacity of Unit 2, and thus provide the benefit of additional power to I&M's customers at no additional cost.

² We note that Petitioner's Confidential Exhibit 1-C, an updated forecast of the LCM Project cost, indicated that as of November 2012, the Project was forecast to be within 1% of the \$1.169 billion cost estimate.

Mr. Chodak explained I&M is proposing an ongoing regulatory review process for the LCM Project. He stated the Company has a rigorous internal project management process that requires any cost estimate or budget changes to be thoroughly justified, and he invited the Commission to review the management of the Project construction through periodic reviews. Mr. Chodak indicated the Company is also willing to retain a third-party expert to monitor and report findings to the Commission and stakeholders. The ongoing review process proposed by I&M would have the Commission conduct ongoing reviews of the construction of the LCM Project every 6 months, in concert with the Company's 6-month rate adjustment filings.

Mr. Chodak concluded his direct testimony by emphasizing that timely recovery of the LCM Project costs via a rate adjustment mechanism is both necessary and appropriate, for several reasons. First, the magnitude of the LCM Project costs are significant, and without timely cost recovery, it would be difficult for I&M to maintain its credit quality and access to credit on reasonable terms, both for financing this LCM Project, as well as for financing other ongoing capital expenditures. In Mr. Chodak's view, a comprehensive and integrated regulatory strategy is needed to assure that the LCM Project is approved as reasonable and necessary, and that timely cost recovery, including a cash return on construction work in progress ("CWIP"), is authorized. Additionally, Mr. Chodak pointed out that CWIP ratemaking treatment will have the effect of lowering the overall costs of the Project and more gradually increasing customer rates.

On cross-examination, Mr. Chodak emphasized the credit quality implications of the requested regulatory treatment. He indicated the Company is currently earning a 4 percent return and its weighted average cost of capital is over 7 percent. He expressed concern that without the special regulatory treatment allowed by statute for the LCM Project, I&M's credit metrics may go below what is acceptable to maintain its current BBB credit rating. Tr. at A-31; A-74 thru A-79; *see also* Tr. at B-19 thru B-21.

B. John Torpey, Director-Integrated Resource Planning for American Electric Power Service Corporation. Mr. Torpey testified concerning I&M's integrated resource plan ("IRP"), and specifically, the IRP analyses performed by the Company demonstrating that the LCM Project is the preferred resource alternative. Mr. Torpey testified that I&M filed its most current IRP on November 1, 2011, encompassing a twenty-year planning period (2012-2031). See Pet.'s Ex. JFT-1. The Cook Units are included in the resource plan through the end of their current (extended) operating licenses, 2034 for Unit 1 and 2037 for Unit 2. Mr. Torpey explained the Company's IRP analyses demonstrate that a portfolio that includes the Cook Units for their twenty-year extended license periods is in the best economic interests of I&M and its customers.

In connection with its 2011 IRP, I&M analyzed the cumulative present value of revenue requirements ("PVRR") associated with investing in the Cook Plant to allow it to continue operating under its renewed licenses, compared to the PVRR associated with retiring the two Units and replacing each with alternative resource options. The costs assumed to retain the Cook Units included the costs associated with performing the LCM Project, plus ongoing capital and operation and maintenance ("O&M") costs. The costs of alternative resource options were based on industry data and recent AEP projects. Other major assumptions included new environmental

requirements, resulting in retrofits at Tanners Creek Unit 4 and Rockport Units 1 and 2, and retirement of Tanners Creek Units 1 through 3.

These analyses indicated that making the LCM Project investment and retaining the availability of the Cook Units is the preferred option at capacity factors for the Cook Units greater than 20%. Mr. Torpey noted, depending on refueling outages, the projected Cook Units' capacity factors are estimated to range in percentage from the high-seventies to mid-nineties. Thus, he concluded, the option of making the LCM Project investments and continuing operation of the Cook Units has a significant cost advantage over other alternatives.

Mr. Torpey testified that, subsequent to the 2011 IRP, the Company used the Strategist[®] model to perform additional IRP analysis of the LCM Project, specifically analyzing the Cook LCM Project scenario (including LCM capital, other ongoing capital and an assumption of capital costs for Clean Water Act 316(b) compliance), versus a scenario that replaces the Cook Units with natural gas simple cycle and combined cycle facilities. These additional analyses considered both a base case and a low natural gas price case. Mr. Torpey testified the results of these additional analyses also indicated that the LCM Project is a far preferable option than other resource alternatives. More specifically, these analyses indicated that the PVRR benefits to customers of a resource portfolio including the LCM Project and continued operation of the Cook Units, versus a portfolio where the Cook Units are retired in the near future, are in the range of \$3.1 billion to \$4.5 billion.

C. Michael H. Carlson, Director of Nuclear Technical Projects at the Cook Nuclear Plant. Mr. Carlson provided an overview of the Cook Plant and I&M's Nuclear Generation Group and the oversight provided by the NRC, with particular emphasis on the twenty-year license renewals granted for the Cook Units. Mr. Carlson also described the LCM Project and why it is needed, and offered support for the estimated LCM Project cost and schedule.

Mr. Carlson explained the Cook Plant is a 2-unit nuclear power plant located along the eastern shore of Lake Michigan, in Bridgman, Michigan. Units 1 and 2, owned and operated by I&M, are both pressurized water reactor designs with a 4-loop Westinghouse nuclear steam supply system. The combined nominally-rated net electric output for both Units is 2,191 MWs, and is essentially emission free.

Mr. Carlson testified that I&M's Nuclear Generation Group consists of approximately 1,200 full time I&M employees, plus 100 to 200 contract employees on a long-term basis and 600 to 1,000 temporary contract workers during outages. Mr. Carlson characterized the performance of the Cook Nuclear Generation Group as excellent, and as one of continual improvement. As an example of the Group's excellent performance, Mr. Carlson pointed to both the 2008 Unit 1 turbine failure and the improvement in refueling outage durations. Mr. Carlson explained that, in September 2008, the Unit 1 turbine failed; the plant's safety systems and operators acted immediately and were able to shut down the Unit in a safe manner without any issues or injuries, and were able to repair the turbine and return it to service in approximately half of the time it would have taken to perform a full replacement. He also explained that refueling outage durations at the Cook Plant have significantly shortened over the last few

decades, which has led to increased plant capacity factors and has enabled I&M to provide more low-cost generation to its customers.

Concerning NRC oversight of the Cook Plant, Mr. Carlson explained that the NRC is empowered to license and regulate civilian nuclear power plants. Toward that end, the NRC has provided the Cook Plant with specific technical requirements through regulations regarding the components and systems that must be incorporated into the design of the plant systems to ensure the protection of public health and safety. The NRC requires compliance with these regulations during facility operation, in part, by incorporating certain technical specifications into the Cook Plant operating licenses. If the Cook Plant is determined to be out of compliance with NRC regulations or the terms of its operating licenses, the NRC has the authority to shut the plant down. The NRC safety regulations provide a framework to ensure the safe operation of the Cook Plant, and virtually all of the activities associated with the operation and maintenance of the Cook Plant are under the comprehensive regulation and continuous inspection of the NRC. These regulations include requirements for equipment reliability, including periodic equipment testing. Additionally, maintenance is regulated, inspected, and monitored under the NRC's "Maintenance Rule."³

On cross-examination, Mr. Carlson expanded on the relationship between "safety" and "reliability" at nuclear power plants. He noted that in nuclear parlance, the reactor side of the plant is "safety-related," while the secondary, steam side of the plant is "non-safety-related." He emphasized, however, that while technically the NRC may categorize certain equipment as "non-safety," that equipment may have significant safety implications. He noted the NRC's Maintenance Rule requires that "non-safety" equipment, as well as "safety" equipment, be maintained and reliable. According to Mr. Carlson, "the maintenance rule gets into the heart of having reliable systems throughout the plant . . ." Tr. at C-27, C-28, C-58.

With regard to NRC license renewal, Mr. Carlson explained that the process requires a significant review of the plant and its processes to assure the safety margins associated with the current licensing basis⁴ will be maintained during the period of the renewed license. Among other things, the NRC focuses on managing adverse effects of aging, with the intent of ensuring that important systems, structures, and components ("SSCs") will continue to perform their intended function in the period of extended operation. Prior to submission of a renewal application, an applicant must analyze the management of aging effects in sufficient detail to conclude that the plant can be operated safely during the period of extended operation. The applicant must provide the NRC with an evaluation that addresses the technical aspects of plant aging and describes the ways those effects will be managed over the life of the plant.

Mr. Carlson stated that, in order to meet the criteria for a license renewal, nuclear plants must make commitments for managing the aging of passive, long-lived components, and the plant must meet the set of established NRC requirements in order to continue operating. In obtaining the license renewals, I&M committed to the NRC that certain programs and activities

³ 10 C.F.R. § 50.65.

⁴ The "current licensing basis" is the set of NRC requirements applicable to a specific plant and a licensee's written commitments for ensuring compliance with and operation within applicable NRC requirements and the plant-specific design basis. Pet.'s Ex. O at 10.

will be performed, or be in place, prior to the commencement of the period of extended operation. I&M must complete these activities no later than October 25, 2014, for Unit 1 and December 23, 2017, for Unit 2, and must notify the NRC in writing when implementation of these activities is complete and can be verified by NRC inspection. Mr. Carlson testified the LCM Project is instrumental in allowing Cook to replace or upgrade components to maintain their functions, in lieu of other alternatives, such as frequent surveillances, inspections, and maintenance.

In sum, Mr. Carlson testified that replacement and/or additional maintenance of components are required to maintain the reliability of equipment and associated safety margins. The Cook Plant was originally designed and built based on an expected life of forty years. Extended operation to 60 years requires the plant's SSCs be inspected, maintained, refurbished, and replaced on a managed basis. The renewed twenty-year licenses require that actions be taken to ensure the effects of component aging are appropriately managed during the extended license period and that the Cook Plant complies with NRC regulations and applicable technical specifications.

With regard to life cycle management, Mr. Carlson testified that the standard industry definition of life cycle management is:

The integration of aging management and economic planning to optimize the operation, maintenance, and service life of Systems, Structures, and Components (SSCs); maintain an acceptable level of performance and safety; and maximize return of investment over the service life of the plant.

Pet.'s Ex. F at 10-11. Simply stated, Mr. Carlson explained that life cycle management is a process for the timely detection and mitigation of aging effects in SSCs that are important to plant safety, reliability, and economics. With regard to the Cook Plant's LCM Project, Mr. Carlson emphasized that the Company further defines life cycle management as being limited to non-recurring capital replacements required to operate for an extended license period.

Mr. Carlson testified that the Cook LCM Project is comprised of 117 sub-projects, all being performed for the single purpose of allowing the plant to safely and reliably operate during the extended license periods. He confirmed on cross-examination that none of the sub-projects are unrelated to safety or reliability of the Plant and that many of the sub-projects are related to both safety and reliability. Tr. at C-63, C-87. The implementation of the LCM Project is scheduled to be complete in 2018. Major activities for each sub-project included in the LCM Project include study, design, long lead equipment procurement and delivery, construction, and turnover to plant operations. Mr. Carlson testified that without capital to support the LCM Project, the Cook Units would have to be shut down prior to fulfilling their extended licensed life due to equipment degradation.

The sub-projects that make up the LCM Project were identified through the Cook Plant's nuclear asset management planning processes. More specifically, the sub-projects were initially identified after a 2010 feasibility study performed by an engineering, procurement, and construction ("EPC") contractor in connection with a potential power uprate (the "Feasibility

Study”). As part of this study, the EPC contractor performed an extensive evaluation of the existing plant systems and components, taking into consideration the operating license extensions. To perform this Feasibility Study, the EPC contractor and the Company conducted a thorough analysis of the existing plant equipment, reviewing plant design bases, licensing bases, design documents, operating data, and input from plant managers. Following this analysis, specifications and technical data sheets were prepared and issued to suppliers for solicitation of equipment and/or materials. The final study resulted in a preliminary definition of the required modifications and provided a budgetary EPC cost estimate to implement both the LCM Project and a potential power uprate. Although I&M has decided not to pursue a power uprate at this time, Mr. Carlson explained that the study served a valuable purpose in its identification and analysis of the LCM Project work that needed to be performed.

Next, Mr. Carlson stated I&M reconsidered the Feasibility Study and developed a more precise methodology for identifying a complete list of LCM sub-projects. Petitioner’s Exhibit MHC-8 contains a flow diagram illustrating I&M’s methodology. In general, Mr. Carlson testified, the LCM sub-projects are capital projects associated with critical SSCs or regulatory functions; in addition, they are one-time replacements to address aging, obsolescence or unit reliability associated with the license extension.

Mr. Carlson testified that alternatives, where they existed, were evaluated with respect to the LCM sub-projects. However, he emphasized that “doing nothing” is not an option; if the sub-projects are not performed, the Cook Plant will be unable to fulfill the extended license lifespan. Analysis of alternatives focused on “like for like” replacements for systems where the technology has not changed significantly, and on updated systems and components for systems which are being replaced due to obsolescence. Mr. Carlson explained that alternatives for each sub-project will also be reviewed by internal company stakeholders on an ongoing basis, allowing for continued evaluation as more information is received through detailed engineering and design.

Mr. Carlson testified that while a power uprate is not being performed at this time, it remains a viable option for the future. Accordingly, the proposed LCM Project includes seven components – certain heat exchangers, transformers, and pumps -- that are sized (*i.e.*, “upsized”) for a future uprate. Mr. Carlson indicated that sizing these LCM Project components for a future potential uprate will avoid having to replace these components at a larger cost in the event of a future power uprate. He also explained that the upsized components will provide benefits, with or without a power uprate.

With regard to the proposed Project schedule, Mr. Carlson explained that some of the sub-project work can be performed while the Units are online; however, most of the sub-project work will be performed during upcoming major refueling outages on both Units. These major refueling outages provide Cook with discrete timeframes to replace components that are required for the plant to be operable. With regard to the estimated Project cost, Mr. Carlson’s testimony showed the annual anticipated Project expenditures from 2011 through 2018, with a total estimated cost of \$1.169 billion. Mr. Carlson opined that the cost estimate is reasonable considering the degree of engineering and design work to date, as well as the proposed Project schedule.

On cross-examination, Mr. Carlson provided further explanation as to why certain specific sub-projects were reasonable and necessary. For example, with respect to the technical support center and north access building sub-projects, he explained that the proposal is to make those two facilities one building, outside of the Plant itself. Currently, the technical support center is inside the Plant, which is problematic because in the event of an accident or postulated accident, the center would need to be manned, but the Plant itself could experience high dose radiation, which would require evacuation. Accordingly, the current technical support center is inadequate and at risk of NRC issues during drills. The north access building, while initially adequate, Mr. Carlson explained, is inadequate now because the number of people required to be processed during outages has increased significantly over the years; and the procedure and check requirements have increased, as well. The north access building is similarly at risk of NRC issues during drills, according to Mr. Carlson. Mr. Carlson further explained that, the 2011 Fukushima event in Japan resulting from an earthquake and tsunami, among other things, demonstrated that nuclear power plant managers and regulators must consider the possibility of events that affect all units at a site, making the technical support center and north access building sub-projects even more important for safety preparedness. Tr. at C-19 thru C-25; C-70 thru C-72.

Regarding the transformer sub-projects, Mr. Carlson explained the Cook transformers are nearing the end of their forty-year design lives, and the transformer sub-projects are intended to replace these aging transformers, and provide for one spare transformer and one spare phase for the generator step-up transformer on-site at the Cook Plant. He emphasized that transformers, including on-site spares, are important to both safety and reliability at a nuclear power plant. For example, not only are transformers essential to deliver power from the plant to the grid, but they are also essential for providing off-site power to the plant when the units are shut down. Additionally, reliability is important to cost-effective operations. Pet.'s Ex. F at 16-17, Tr. at C-73 thru C-75; C-82 thru C-84.

D. Paul Schoepf, Director of Nuclear Projects at the Cook Plant. Mr. Schoepf adopted the prefiled initial direct testimony of Mr. Terry Brown, with some corrections and clarifications. See Pet.'s Ex.'s G and H. Mr. Schoepf addressed the Project engineering, management, construction, contracting strategy, and cost controls, including details about the planning, initiation, execution, monitoring and control, and close out for the LCM Project. He also testified concerning the development of the LCM Project cost estimate.

Regarding the cost estimate, Mr. Schoepf testified the LCM Project cost estimate through 2018 is \$1.169 billion, which includes actual costs incurred in the 2nd half of 2011. Petitioner's Confidential Exhibit TJB-5 reflects the estimated cost of each of the sub-projects, including actual and forecast capital expenditures, along with the sub-project schedule (outage versus non-outage) and projected in-service years. Mr. Schoepf explained the Project cost estimate is a "bottoms-up" estimate, meaning that individual cost estimates were developed. The cost estimates from the EPC contractor were benchmarked by I&M and also by a third party, and some of this work was then re-bid to other vendors. He testified the sub-projects have also been vetted through internal review boards to ensure the accuracy of scope and cost estimates.

Mr. Schoepf testified the cost estimate accuracy for a given sub-project was generally dependent upon the execution phase, with Phase 1 sub-projects at +/- 50% accuracy; Phase 2A sub-projects at +/-25% accuracy; Phase 2B sub-projects at +/-15% accuracy; and Phase 3 sub-projects at +/-10% accuracy. Due to the nature of the bottom-up estimate and the multi-year aspect of the LCM Project, he stated the level of accuracy of the overall Project cost estimate is evolving. However, Mr. Schoepf explained that the accuracy of the sub-project estimates does not indicate the accuracy of the overall Project estimate, for several reasons. First, there are no “first of a kind” sub-projects. Second, the cost estimates have been internally and externally benchmarked. Third, several sub-projects are more advanced, providing more assurance as to cost. Finally, the diverse nature of the sub-projects, along with being constructed over 6 years, increases the likelihood that cost increases will offset cost decreases. Nevertheless, while Mr. Schoepf expressed a high degree of confidence in the LCM Project cost estimate, he emphasized that it would be unrealistic to assume that all potential anomalies have been recognized and accounted for in the estimates. Accordingly, the Company has included an approximately 20% reserve to the overall LCM Project cost estimate.

On cross-examination, Mr. Schoepf confirmed that the LCM Project study costs for which the Company is seeking recovery totaled \$12.4 million, and those study costs were allocated to the 32 sub-projects cost estimated by the EPC contractor in the Feasibility Study. Mr. Schoepf also confirmed that included in the sub-project cost estimates and the management reserve cost amount are indirect costs (approximately 10%). He explained that indirect costs are project costs that are not within the control of a project manager – costs such as company overheads, building rental, and utilities; they are real costs, just not directly controllable by a project manager. Mr. Schoepf also explained that, in addition to indirect costs, AEP direct costs are included in the sub-project cost estimates. AEP direct costs include costs associated with project managers, cost analysts to track costs, schedulers and planners – real costs that a project manager can control. With regard to the 32 sub-projects initially estimated by the EPC contractor in the Feasibility Study, Mr. Schoepf explained that the Company removed contingency from the Feasibility Study sub-project estimates, and added both AEP direct and indirect costs to arrive at the filed sub-project cost estimates. For the remainder of the smaller sub-project cost estimates, the Company developed the cost estimates then added indirect costs. Tr. at D-48 thru D-52; D-62 thru D-65; E-83; E-101; E-106; F-35 thru F-38.

Regarding the management reserve, or contingency, included in the Project cost estimate, Mr. Schoepf explained that a total of \$200 million⁵ of the Project costs has been allocated to the management reserve costs. Mr. Schoepf clarified that while the Company’s initial testimony discussed both the concepts of “risk reserve” and “management reserve” – two forms of contingency – the Company had not included any risk reserve in the initial Project cost estimate, so that the only contingency included in the initial Project cost estimate was the \$200 million of management reserve. Control of this management reserve resides with the Director of Nuclear Projects, the Chief Nuclear Officer, and the I&M President. Mr. Schoepf explained that a sub-project manager can only access the management reserve after justifying the need with a documented request. Each such request will be formally reviewed by the Cook Projects

⁵ Mr. Schoepf clarified in his rebuttal testimony that management reserve includes indirect costs. Therefore, the management reserve consists of \$200 million plus \$20 million in indirect costs, for a total of \$220 million.

Department management, and will be elevated to senior Cook management if warranted, depending upon the magnitude of the requested change.

Mr. Schoepf explained that the Company planned to self-manage the LCM Project versus using outside firms to engineer, procure and construct the sub-projects. The contracting approach to be used will depend upon the particular sub-projects and the level of risk. I&M will utilize the most cost-effective contracts available, generally either time and material, fixed cost, or a combination, with competitive procurement processes used for external resources.

Mr. Schoepf also provided an overview of the Projects Department for the Cook Plant and the project management processes and controls in place for the LCM Project. He explained the Projects Department currently consists of five major groups: Project Controls; Projects; Projects Engineering; Projects Construction; and Dry Fuel Storage. The Projects Department, tasked with managing major projects such as the LCM Project, is composed of numerous individuals with significant education and experience in project management, nuclear operations and plant management. In addition, the Projects Department has a broad array of procedures, desktop guides, and project management guidance tools available to it, to assist with project management at the Cook Plant. These procedures, guides and tools are consistent with principles and standards outlined by the Project Management Institute's "Project Management Body of Knowledge" ("PMBOK")⁶ and the Institute of Nuclear Power Operation's ("INPO") "Excellence in Nuclear Project Management."⁷

Mr. Schoepf explained that approval of major projects, such as the LCM Project, involves approval by several internal committees and groups prior to funding or implementation, following a feasibility study, options screenings and priority recommendations, and a formal Capital Improvement requisition. However, projects with a total cost of less than \$500,000 are approved by only a few committees. Project planning begins only after a proposed project has gone through the various approvals, including approval of the Capital Improvement requisition by the Sub-Company Board for projects estimated to cost greater than \$500,000.

Mr. Schoepf testified that the LCM Project sub-projects will be executed using a phased project management process, generally consistent with the principles and process standards outlined in the PMBOK. Phases 1 and 2 are Project Initiation and Project Planning (including procurement, with sub-phases for preliminary design and engineering; and detailed engineering and design); Phase 3 is Project Implementation; and Phase 4 is Project Closeout. Phase 1 activities include a feasibility study, preparation and approval of a Capital Improvement requisition (with a cost estimate accuracy of +/- 50%), and conceptual engineering. Formal approval of a revised Capital Improvement requisition at the end of Phase 1 (with a cost estimate accuracy of +/- 25%) allows the project to proceed to Phase 2A. Phase 2A activities include

⁶ The PMBOK is a collection of processes and knowledge areas generally accepted as best practices within the project management discipline; it is an internationally recognized project management standard, providing the fundamentals of project management for all types of projects, including construction projects. Pet.'s Ex. G at 4.

⁷ INPO 09-002, "Excellence in Nuclear Project Management," discusses concepts similar to those addressed in PMBOK, but also concentrates on additional processes that are unique to nuclear power, *e.g.*, incorporation of nuclear reactor safety concerns, radiation dose control ("As Low As Reasonably Achievable"), and use of operating experience from other nuclear facilities. Pet.'s Ex. G at 4-5.

preliminary engineering, permitting, and procurement work. Upon completion of Phase 2A, the project design is 20% complete and the Capital Improvement requisition is again revised (to a cost estimate accuracy level of +/- 15%), for approval again by several internal oversight groups. Phase 2B consists of completing detailed engineering and design as well as procurement of major and long lead time equipment. During this phase, as detailed design progresses, construction bid packages are prepared and major equipment is specified, bid, and purchased. Additionally, the construction and site management teams are mobilized and begin site construction work. Upon completion of Phase 2B, the project is reviewed once again, and a Phase 3 Capital Improvement requisition (with a cost estimate accuracy of -10% to +0%) is prepared for internal approvals. Key activities in Phase 3 consist of full-scale construction, start-up, testing, check-out and commissioning of the project. Phase 3 is complete when the equipment is commissioned and placed in service. Phase 4 involves closeout of contracts and services, finalizing of engineering design documents, and completion of a project critique by the project manager. Prior to closing the project, a project closeout checklist is completed.

According to Mr. Schoepf, this phased approach to project management provides structured control of the project scope and costs, using a common platform of project management understanding – the PMBOK. The phased approach also provides a minimum of three specific decision points (the end of Phases 1, 2A, and 2B) where engineering and design, cost, and schedule are reviewed to ensure they are meeting the intent and expectations of the project.

Mr. Schoepf testified that each sub-project has a scope management plan that describes the processes involved in ensuring the sub-project includes all of the work required, and only the work required, for completing it successfully. Project scope control ensures that significant changes in project activities are effectively identified and managed to preclude unanticipated or undesirable effects on sub-project deliverables, cost, or schedule. Potential problems and changes to the work are recognized, evaluated, and addressed in a timely manner. According to Mr. Schoepf, effectively managing scope is a key contributor to successful execution of a sub-project on schedule and within budget.

Mr. Schoepf further explained that requests for a change in the scope of a sub-project will be reviewed and analyzed by the project team and project manager, project sponsor, and project director, as necessary. The project manager has authority for approving minor changes in task scope, task completion dates, task cost targets, and risk estimates that do not affect the overall sub-project scope, completion dates, or cost targets. Significant changes, however, require project sponsor and project director approvals, and will go through a Project Change Request Form (“PCRF”) process. A PCRF must be completed when one or more of the following conditions apply: (1) scope is added or excluded from the original baseline; (2) the change requires additional funding from the LCM Project management reserve (contingency); or (3) there is a schedule change that impacts a milestone or causes a re-baseline. Only approved changes may be implemented.

Mr. Schoepf testified that I&M will manage the LCM Project risk by initiating a risk management plan for each sub-project of the LCM Project as part of its Phase 1 activities. He said this activity is undertaken to help ensure that I&M and the Cook Plant are protected against

inadequate performance in the areas of cost, schedule, and quality. During this process, uncertainties or risks are distinguished from known challenges; and mitigation strategies are developed for known challenges. Risks will be further defined as the project definition is elaborated in later phases. He stated that part of this elaboration is the development of a risk register. In this exercise, the critical project risks are prioritized so that project resources can be efficiently focused on mitigation efforts. Mr. Schoepf testified the risk registers are “living documents” that evolve through the phased sub-project execution process, progressing from more risky to less risky as the sub-project progresses.

Mr. Schoepf explained that the LCM Project cost and schedule would be monitored and controlled through the Cook Plant’s Project Controls group, which is independent from the rest of the Projects Department so an objective review of the progress of each sub-project can be achieved. Mr. Schoepf stated that, for cost and schedule, I&M uses Earned Value Management as a tool, to assess how well cost and schedule are being controlled. Both cost and schedule are updated monthly and reviewed in Company project status meetings. Project schedules are also monitored by reviewing milestone adherence.

Mr. Schoepf also explained the type of training employees at the Cook Plant receive, as well as the management processes relative to the LCM Project. Mr. Schoepf emphasized that there are processes in place that provide project management oversight on a daily, weekly, monthly, and quarterly basis. Mr. Schoepf also noted that no federal, state, or local permits are required to execute the LCM Project, and the LCM Project will not require any modifications to the transmission system that interfaces directly with Cook Plant.

E. Steven M. Fetter, President of Regulation UnFettered. Mr. Fetter, an independent utility advisor, testified concerning the credit quality implications of regulatory treatment for the Company’s LCM Project. Mr. Fetter generally described the credit rating process for utilities, and the importance to credit rating agencies of the quality of regulation and the timely recovery of prudent costs. He testified that a utility with strong credit ratings is not only able to access the capital markets on a timely basis at reasonable rates, it also is able to share the benefit from those attractive interest rate levels with customers, because the cost of capital gets factored into utility rates.

Mr. Fetter testified, amidst the still uncertain global economy, he reviewed the implications on I&M’s credit quality if the Commission were to deny the ratemaking and accounting requested by the Company in this proceeding. His review compared two alternative methods of recovering LCM Project costs from I&M’s customers. The first method assumed the Commission (and the Michigan Public Service Commission) would permit I&M to recover its LCM Project costs on a timely basis (including CWIP), consistent with recently-enacted Indiana legislation. As a point of comparison, he analyzed a second alternative – not proposed in this case – which would provide for accrual of financing costs through allowance for funds used during the capital investment program (“AFUDC”). He noted the first method, in addition to improving the Company’s cash flow during the period of construction, minimizes the total cost of financing the LCM Project through an ongoing collection of financing costs on the CWIP during the period of capital investment.

Mr. Fetter offered his view that the current trend across the U.S. is for regulators to take proactive steps to be supportive of utilities' financial and credit rating standing during times of significant capital investment undertaken to meet customer needs. He explained that I&M's current "BBB / Baa2" credit ratings status may overstate to a degree the Company's financial strength. He testified the Company's proposal to recover financing costs on CWIP during its capital investment period, along with supportive regulation, should provide the cash flow necessary to allow the Company to stabilize its current credit profile, with a longer term goal of improving its credit ratings, a step that should reduce both access and cost pressures related to ongoing financing needs.

Mr. Fetter opined that the absence of recovery of financing costs through CWIP during the capital investment cycle could stress I&M's risk profile and create the potential for a downgrade. Such downgrade, were it to occur, would come during a period of continuing unease within the U.S. financial sector and capital markets and would place the Company's ratings at the lowest investment grade level. A two-notch downgrade would place the Company's debt below investment grade, *i.e.*, "junk bond" status. He stated any such negative rating action would increase I&M's costs, not only for the LCM Project, but for all financing the Company will be required to undertake to carry out its utility operations during this period. Avoiding the higher financing costs that would accompany such negative rating action would minimize the rate impact on customers and should serve to maintain investor interest in the Company.

Mr. Fetter discussed the consequences that occur when a utility falls below investment grade status. He noted that if a utility were to have its credit ratings fall below investment-grade quality, there would be a marked change in the investor profile for that utility. Major utility investors such as insurance companies and pension funds operate under legal restrictions that severely limit their ability to invest in below investment grade debt instruments. He noted mutual funds could also be affected based upon what a particular fund has communicated to investors as to its investment profile. Moreover, he stated, a utility with a junk bond rating would certainly have to pay significantly more to finance an ongoing construction program, and likely would have to post bond or put up cash as collateral in various contracts (such as for energy supply) or to meet certain regulatory commitments (such as Independent System Operator agreements or environmental remediation requirements).

Mr. Fetter concluded his testimony by stating that sustained and consistent regulatory support for recovery of prudent expenditures made by utilities to further public policy goals is viewed very favorably by the financial community.

F. Scott Krawec, Director of Regulatory Services. Mr. Krawec testified concerning the Company's requested ratemaking and accounting treatment related to the LCM Project. Mr. Krawec testified regarding his understanding that the Indiana General Assembly passed Senate Bill 251 in 2011. He testified this legislation, among other things, authorized financial incentives, including timely cost recovery for the study, analysis, development and life cycle management of nuclear energy generating facilities, as well as for projects to enhance the safe and reliable use of nuclear energy production facilities.

Mr. Krawec summarized the ratemaking and accounting authorizations requested by the

Company with respect to the LCM Project, as follows: (1) timely recovery via a periodic rate adjustment mechanism (to be updated approximately every 6 months) of: (a) financing costs for sub-projects under construction on and after January 1, 2012; (b) post-in-service financing costs and incremental depreciation and property tax costs incurred on and after January 1, 2012; and (c) study, analysis and development costs; (2) interim deferred accounting treatment for certain O&M costs (incremental depreciation and property tax costs) and study, analysis and development costs; and (3) the addition of LCM earnings to the Company's authorized net operating income for fuel adjustment charge ("FAC") statute test purposes.

Mr. Krawec explained that the Company's proposed periodic rate adjustment mechanism, (the "LCM Rider" or "LCMR") is a periodic rate adjustment mechanism for timely recovery of LCM Project costs and associated study, analysis and development costs. According to Mr. Krawec, the LCMR will provide efficient and timely recovery of actual CWIP financing costs and post-in-service costs associated with all of the sub-projects within the LCM Project.

Mr. Krawec noted that a tracker allows for sufficient oversight and prudence review but requires fewer Commission resources than are required for a full rate case, and that without the LCMR, the Company would not be able to avoid multiple base rate cases in the near future. He stated the LCMR will also avoid rate shock for customers, by effectively phasing in the costs of the LCM Project over time. Additionally, under the proposed LCMR, I&M will be able to avoid accruing considerable debt and equity AFUDC amounts that would ultimately increase I&M's rate base. Also, the LCMR will reflect accumulated depreciation on the completed projects contemporaneously as a rate base reduction. As such, the LCMR should reduce the number and frequency of future base rate filings that I&M would have to make to recover expected future incremental costs for known and approved projects and programs.

Mr. Krawec explained I&M proposes to defer on an interim basis any post-in-service depreciation expense, less depreciation discontinued on corresponding components retired, as well as incremental property tax expense, and carrying costs, for future recovery until the LCMR is implemented. At the time the LCMR is implemented, I&M proposes to recover carrying costs on LCM sub-projects that are under construction but have not yet been placed in-service, calculated using the Company's AFUDC rate, with a corresponding cessation of the recording of AFUDC on such sub-projects.

Mr. Krawec also explained I&M was requesting in this filing that the proposed LCM Rider be approved correspondingly with the approval of the LCM Project. He stated the proposed initial LCM Rider rates were developed using the forecasted Project costs through June 2013 for the sub-projects planned to be under construction and/or completed through that date. Mr. Krawec identified and described the information the Company provided in this proceeding and will continue to provide in its semi-annual tracker update.

Finally, Mr. Krawec stated the Company is proposing that an ongoing review process be conducted as part of I&M's semi-annual LCMR proceedings. Under the Company's proposal, I&M will include progress reports and any revisions to cost estimates for the LCM Project in conjunction with the LCMR filing.

On cross-examination, Mr. Krawec confirmed I&M was not seeking recovery via the LCM Rider or interim deferred accounting treatment for any costs or expenses other than financing costs, incremental depreciation expenses, incremental property tax expenses, and study, analysis and development costs. With regard to study costs, he noted that such costs were allocated to certain of the sub-projects, and that they were actual costs, not estimates. Tr. at H-3, H-4.

G. Michelle Howell, Regulatory Analyst for AEP. Ms. Howell testified concerning the Company's calculation of the LCMR rates and explained the methodology for updating the LCMR semi-annually. Ms. Howell also sponsored the exhibits containing the Company's initial proposed LCM Rider rates proposed to go into effect with issuance of a Commission Order in this Cause.

Ms. Howell noted the LCMR cost calculation consists of two components: (1) a projection of LCM Project costs, and (2) a prior period cost reconciliation. A reconciliation of prior period costs will not be included in the LCMR until the filing of the second revision to the LCMR expected late in 2013, which is expected to incorporate the reconciliation of actual costs to actual billing under the LCMR through June 2013. She stated until the second revision, the reconciliation component will be zero.

Ms. Howell explained that Indiana's portion of the LCM costs were allocated to the rate classes based upon the demand and energy allocation parameters established by the Commission in Cause No. 43306, as shown in Petitioner's Exhibit MMH-1. The proposed LCMR rates were calculated after the costs were allocated to each tariff class, and an energy rate was calculated using the forecast billing energy for that class.

Finally, Ms. Howell testified that upon initial implementation of the LCMR, residential customers using 1,000 kWh of electricity per month would see a monthly rate increase of approximately \$1.52, or 1.8%, when compared to rates which were approved in Cause No. 43306.

5. OUCC's Evidence.

A. Ronald L. Keen, Senior Analyst for the OUCC. Mr. Keen provided an overview of the OUCC's position in this case. He testified that the OUCC generally supports I&M's plans to upgrade, maintain and operate the Cook Plant in a safe and reliable manner in order to continue providing energy to Indiana ratepayers. Notwithstanding this general support, the OUCC recommended the Commission:

- (1) Deny cost recovery of approximately \$220 million representing the OUCC's concerns with the cost estimating process (*i.e.*, use the low end of the Company's estimate ranges rather than the midpoint of the ranges): Should I&M present data which sufficiently substantiates its cost estimates, this amount, or a portion of it, may be eligible for recovery in subsequent LCM tracking update proceedings.

- (2) Authorize normal cost recovery for a maximum of approximately \$9 million for sub-projects the OUCC believes are not defined sufficiently at this time to be classified as LCM until such time as I&M presents evidence clearly demonstrating these sub-projects should be included as LCM. If I&M presents sufficient evidence, the OUCC recommends the cost for each approved project be included as costs recoverable in a later LCM tracker update proceeding.
- (3) Exclude approximately \$312 million from the LCM tracker for those sub-projects the OUCC believes are not related to LCM, as detailed in both Mr. Keen's and Mr. Sobel's testimony. The OUCC also recommends I&M be required to identify any costs related to installing "upsized" equipment to accommodate a capacity uprate for the Cook Plant in any proceeding where I&M seeks recovery of those costs.
- (4) Deny I&M's request for inclusion of the \$220 million management reserve fund in the total recoverable costs for the LCM Project.
- (5) Require I&M to adjust base rates or to provide a credit in the LCM tracker for all costs associated with replaced equipment that is included in base rates.
- (6) Deny I&M's request to defer and record as a regulatory asset the post-in-service depreciation, carrying costs, and O&M expenses on the sub-projects.
- (7) Approve for cost recovery under the proposed LCM tracking mechanism a maximum of approximately \$408 million for sub-projects the OUCC has not opposed or otherwise questioned.

Mr. Keen testified that the industry accepted definition of Life Cycle Management is:

The integration of aging management and economic planning to optimize the operation, maintenance, and service life of Systems, Structures, and Components (SSCs); maintain an acceptable level of performance and safety; and maximize return of investment over the service life of the plant.

OUCC Ex. 1 at 11. He noted this Cause does not examine the total life cycle of the Cook Plant, but only considers the repair and/or replacement of components that I&M believes are required to support the Cook Plant's NRC license extension.

Mr. Keen stated that after attending the technical conference hosted by I&M at the Cook plant in July 2012, the OUCC believes the various checkpoints used in the current process, if used correctly and consistently, may ensure that I&M project managers frequently review the project for efficiency and effectiveness. However, he also stated the OUCC believes a more rigorous oversight program should be in place to ensure ratepayers are receiving the most value for their money. Mr. Keen noted the LCM Project is not a single project, but a group of 117 sub-projects that must be examined at that level.

Mr. Keen expressed the OUCC's concern with the accuracy of cost estimates for LCM sub-projects and the cost recovery methodology associated with those sub-projects, arguing that the costs for some sub-projects should be recovered using more traditional cost recovery methodologies. Mr. Keen also expressed concern with I&M's cost recovery methodology for some of the sub-projects that might not fall within the industry definition of LCM.

Mr. Keen stated the OUCC believes I&M did not supply enough detail on a number of sub-projects to warrant LCM Project cost recovery at the levels requested, particularly with respect to Phase 1 and Phase 2A sub-projects. He explained that, at Phase 1, the scope of the sub-project is designed, but the budgeting is based on conceptual drawings alone. Little engineering design has been accomplished by Phase 1. In Phase 2A, the engineering design work has proceeded to the 20% level and the project management plan has been approved. Consequently, he stated, there is insufficient data available to permit a thorough and detailed cost-benefit analysis of these sub-projects. He noted that the 42 sub-projects currently in Phase 1 account for approximately \$324 million of the total LCM Project cost with an accuracy factor of +/-50%; the 25 sub-projects currently in Phase 2A account for approximately \$480 million of the total LCM Project cost with an accuracy factor of +/-25%; and the 11 sub-projects currently in Phase 2B account for approximately \$119 million of the total LCM Project cost with an accuracy factor of +/-15%.

Mr. Keen stated that the uncertainty of the cost estimate accuracy factors of +/- 50%, 25%, and 15%, depending on the Phase of the sub-project, impacted the OUCC's recommendations, and that because of the limited design and engineering that has been completed in these early phases, the cost estimates could vary as a sub-project moves to a more developed project phase. For this reason, the OUCC recommended the Commission approve funding at the lower end of I&M's acceptable cost estimate range for sub-projects that are deemed to be eligible under the LCM tracker, and allow I&M the opportunity to explain any prudent and reasonable increases in sub-project costs and request cost recovery for any such increases as part of the ongoing review process.

In addition, Mr. Keen expressed concern about differences in the overall cost estimates between those provided by AREVA NP, Inc. ("AREVA") in the Life Cycle Management Project Independent Review, the AEP cost estimates, and those provided in I&M's LCM Project cost forecast. He also expressed concern that the sub-project cost estimates shown on Petitioner's Confidential Exhibit TJB-5 may have been rounded, thus creating inaccuracies.

Mr. Keen also testified about concerns with the management reserve included in the LCM Project cost estimate. Citing to an American Association of Cost Engineers ("AACE") definition of management reserve, Mr. Keen testified the management reserve cost funding of \$200 million (\$220 million with indirect costs included) should have been applied outside of the defined scope of the project, as otherwise estimated. In other words, it should not have been factored into the final LCM Project cost estimate. Mr. Keen stated, while I&M can dedicate a management reserve to the project and can allocate the funds within that reserve, any use of those funds requires, by the AACE definition, a change to the project scope and the cost baseline. Mr. Keen expressed his belief that any use of the management reserve funding is problematic since the scope and/or funding of any single project could be significantly changed

and costs escalated without adequate Commission review, requiring ratepayers to absorb the increased and potentially unsubstantiated costs. I&M should therefore be required to seek Commission approval of such project scope changes in a separate docketed proceeding. However, Mr. Keen indicated this would not alleviate the OUCC's concern, because it was also concerned that the LCM Project cost estimate may contain several layers of contingency.

Mr. Keen also testified that the OUCC believes a number of the sub-projects may not be required by NRC license extension requirements or mandates. Acknowledging the Cook Plant may require work above and beyond the mandates of the NRC license extension to ensure safe, secure, and reliable operations, he indicated the OUCC is not advocating the Commission deny I&M cost recovery for those types of sub-projects. However, in the OUCC's view, it is not proper for equipment common to energy generation facilities to receive specialized cost recovery under Indiana's statutory authorized tracking mechanism. Rather, costs for these sub-projects should be recovered under separate, traditional cost recovery mechanisms already in place and meant for this type of routine equipment. He noted that I&M's LCM Project selection process failed to screen out the turbine and transformer replacement projects despite the fact that these replacements are considered normal tasks of power plant operations and are not unique to nuclear power plants.

Mr. Keen also addressed the OUCC's concerns regarding future uprates at Cook. He noted that I&M is not planning for an uprate of the facility in this case. Rather, the utility is asking to recover costs associated with installing components that would allow the utility (at some point in the future) to apply for a license modification to accomplish an uprate capable of supporting an 18% increase in licensed power. He noted there is no guarantee I&M will request any type of uprate and I&M's IRP does not require an increase in generating capability. Therefore, he testified, the OUCC does not support recovery of any expenses for an uprate at this time.

Mr. Keen agreed the Commission should institute an ongoing review process for the construction of the LCM Project similar to processes contemplated by Ind. Code §§ 8-1-8.5-6 and 8-1-8.8-7. However, he stated the OUCC recommends that I&M be required to file 6-month LCM tracker updates containing detailed information for each sub-project, until one reporting cycle after each sub-project has completed Phase 4 of the I&M phased management process. Mr. Keen testified that the information regarding each reported sub-project contained in the filing should include, at a minimum, the following detail for the previous 6-month period: (1) the current phase of each sub-project; (2) the current sub-project timeline showing milestones and major tasks; (3) a detailed cost expenditure breakout for each sub-project; and (4) the projected final cost estimate for each sub-project based on actual expenditures.

B. Howard L. Sobel, independent consultant and engineer. Mr. Sobel, an independent consultant and professional engineer with extensive experience in the nuclear industry, also testified on behalf of the OUCC. Mr. Sobel reiterated certain of the recommendations identified by Mr. Keen to deny recovery of: (1) the \$220 million management reserve; (2) approximately \$312 million representing LCM sub-projects that are activities more appropriately recovered under traditional rate treatment; (3) approximately \$9 million representing projects characterized by I&M as "not yet fully defined"; and (4) approximately

\$219 million related to I&M's cost estimating process. He stated that because numerous sub-projects do not provide the necessary level of confidence, the OUCC recommends limiting recovery in this case to the lower bound of each sub-project's error band. But, if I&M ultimately demonstrates the costs to have been reasonably incurred, they would be eligible for recovery in subsequent LCM Rider update proceedings.

Mr. Sobel emphasized that while the OUCC was recommending only approximately \$408 million of the \$1.169 billion of LCM Project costs be recovered through the proposed LCMR (*see* OUCC Confidential Exhibit HLS-5), the OUCC was not recommending only certain LCM sub-projects be implemented. Mr. Sobel noted that I&M would not have to forgo implementing necessary safety-related or reliability-related LCM Projects if the OUCC's reduced LCM Rider recovery is approved. Rather, he argued that I&M can instead file for traditional rate case recovery for amounts it believes are necessary to assure continued safe and reliable operation during the extended twenty-year licensing periods.

In support of his position that cost recovery through the LCMR should not be authorized for certain sub-projects, Mr. Sobel questioned whether the sub-projects were truly "life cycle management" projects, whether the sub-projects were required by the NRC, and whether the sub-projects were sufficiently safety-related. Mr. Sobel also questioned the ability of I&M to accurately and consistently estimate the sub-project costs.

While Mr. Sobel questioned whether certain sub-projects were truly LCM projects, he testified to the same definition of "life cycle management" as offered by the Company. He further stated that:

The LCM is the result of the systematic analysis that provides a sufficient level of confidence that a plant designed for 40 years can continue to operate safely and at an acceptable level of performance for another 20 years. The LCM Project considers, among other things, aging effects, operations, maintenance, performance level and safety to determine those actions and activities necessary to achieve that sufficient level of confidence.

OUCC Ex. 2 at 11. Mr. Sobel testified all of the LCM sub-projects should be undertaken since the analysis performed determined they are necessary to achieve a level of confidence to operate the units for another twenty years, but he questioned the type of rate recovery certain sub-projects should receive.

Regarding whether the LCM sub-projects were mandated by the NRC, Mr. Sobel testified that, using I&M's own information, none of the 42 NRC extended license commitments, which are program type commitments, are directly fulfilled by an LCM sub-project. Although he acknowledged that there may be approximately 18 LCM sub-projects that indirectly fulfill an NRC commitment by replacing a piece of equipment rather than establishing a program to inspect, monitor or test it, he stated it was not apparent that any of the remaining 99 LCM sub-projects fulfill any I&M commitments made to the NRC.

With regard to certain sub-projects associated with increasing power output, Mr. Sobel addressed both the Unit 2 turbine replacement and the proposed “upsizing” of seven components for a future potential power uprate. Mr. Sobel noted, while expensive, the Unit 2 turbine replacement after many years of operation is a typical O&M/capital expense. Thus, in his view, the capital associated with the Cook Plant Unit 2 turbine replacement sub-project should be recovered in the normal ratemaking process and excluded from LCM Rider recovery. As support for this position, he cited the Commission’s decision in *Southern Indiana Gas & Electric Company*, Cause No. 44067 (IURC July 11, 2012) (“Vectren Dense Pack”). With regard to the “upsized” components, Mr. Sobel raised several concerns with I&M’s proposal, including challenging licensing issues, cost estimates, and IRP planning. He also noted that Indiana’s LCM statute does not mention uprating or upsizing to accommodate a future uprating; he therefore concluded that costs associated with increasing power levels are not covered under the LCM statute. Regarding upgrades to the polar cranes and modifications to the technical support center and north access building, Mr. Sobel testified that these sub-projects should not be included in the LCM Rider.

Concerning the robustness of the sub-project cost estimates, Mr. Sobel argued that without detailed engineering, it is uncertain what change, addition or replacement may ultimately be decided upon by I&M to address and implement the majority of the LCM sub-projects. More specifically, he testified that it is unknown how many of these sub-projects will ultimately be implemented because I&M has not completed the detailed engineering required to make that determination. Further, the uncertainty in I&M’s cost estimates reflects the level of engineering design completed on these sub-projects. He specifically questioned the Company’s ability to accurately and consistently estimate capital improvement costs based on his review of the AREVA reports and the information contained in OUCC Confidential Exhibit HLS-2, together with the INPO evaluation reports. He also suggested the possibility that certain sub-projects were added to the LCM Project in an effort to get them completed.

Mr. Sobel concluded that the safe operation of the Cook Plant will not be impacted by allowing I&M to recover less than it requested under the LCM Rider, because there are other rate recovery options available. He offered that I&M may file LCM Rider updates to reflect better defined sub-project scope and correspondingly more accurate cost estimates.

C. Bradley E. Lorton, Utility Analyst for the OUCC. Mr. Lorton addressed the relief sought by I&M concerning the seven sub-projects that include costs to make the Cook Plant ready for a potential capacity uprate. Mr. Lorton testified that he reviewed the changes made to the Indiana Code by the Clean Energy Law.⁸ Citing to Ind. Code § 8-1-8.8-1(a)(7), he noted the Indiana General Assembly determined it to be “in the public interest for the state to encourage the study, analysis, development, and life cycle management (“LCM”) of nuclear energy production or generating facilities...” He noted the definition of “nuclear energy production or generating facility” in Ind. Code § 8-1-8.8-8.5(a) and the financial incentives for such facilities provided in Ind. Code § 8-1-8.8-12(a)(2). And, citing to Ind. Code § 8-1-8.8-12(c), he identified the requirements eligible businesses must meet in order for the Commission to grant timely recovery of costs. Mr. Lorton also cited to the requirements of Ind. Code § 8-1-8.8-12(d) concerning the costs that may be recovered.

⁸ Clean Energy Act, Pub. L. No. 150-2011, 2011 Ind. Acts 1492 (2011).

Mr. Lorton explained that Petitioner is requesting \$23 million to prepare for a possible future expansion that may not be necessary. He stated I&M has not provided any cost estimates for the potential uprate and confirmed that no studies or investigations have been made regarding the cost of a potential power uprate of the Cook Plant.

Mr. Lorton testified that I&M is required to submit a twenty-year IRP to the Commission every two years. He stated that Section 8.C.2 of I&M's November 1, 2011 IRP indicated that no new capacity is required until Tanners Creek Unit 4 is retired and the optimal replacement technology for Tanners Creek Unit 4 is natural gas combined cycle. Mr. Lorton described the two capacity scenarios covered in I&M's IRP, one with new capacity additions in the next twenty years, and one without. He stated even in a scenario with no new capacity additions, the IRP indicated I&M would be long on capacity until Tanners Creek Unit 4 is retired in 2024. Mr. Lorton also noted that although I&M's IRP addressed the concept of a nuclear facility uprate, it did not mention a potential capacity uprate for the Cook Plant.

For these reasons, Mr. Lorton testified the OUCC does not support I&M's recovery of \$23 million to make the Cook Plant uprate-ready, and argued that if and when the Cook Plant needs an uprate, I&M could seek cost recovery when it petitions for a certificate of public convenience and necessity ("CPCN") from the Commission to authorize the addition of new capacity. Mr. Lorton further noted that I&M had neither presented evidence to establish that a future uprate to Cook Units 1 and 2 is reasonable and necessary, nor modeled how an uprate would compare with other generation technologies in terms of cost.

D. Wes R. Blakley, Senior Utility Analyst for the OUCC. Mr. Blakley testified about the ratemaking and accounting aspects of the proposed LCM Rider and the OUCC's concerns with certain equipment replacement. He stated the main difference between the LCM Rider and other CWIP trackers is that the LCM Rider is primarily a maintenance and replacement tracker. Because there are 117 sub-projects, scores of these projects will each have rates of return applied with depreciation expenses calculated as well as operating expenses and taxes. He testified such a CWIP tracker will be very large, complex and difficult to review.

Mr. Blakley expressed concern that some of the equipment proposed to be replaced and recovered under the LCM Rider is included in base rates, already earning a return on and a return of through depreciation. Related O&M expenses may also be embedded in current base rates. In addition, at the same time, new equipment that is replacing old equipment is being tracked in the LCM Rider. Thus, Mr. Blakley stated, it appears there could be additional recovery on replaced equipment in base rates at the same time new equipment will be tracked through the LCM. Mr. Blakley stated I&M did not address this potential for over-recovery. Mr. Blakley recommended that I&M adjust base rates to provide a credit in the LCM Rider for all costs associated with replaced equipment that is included in base rates.

Mr. Blakley also took issue with the Company's testimony suggesting the capital structure and cost of capital should be based on I&M's last general rate case. He explained that only the return on equity from the last rate case should be used, with the remainder of the capital structure and cost of capital components updated.

With regard to the Company's requested interim deferred accounting treatment, Mr. Blakely testified that, for each of the sub-projects, I&M is requesting the authority to defer post-in-service depreciation expense, property tax expense and carrying costs (*i.e.*, AFUDC) for recovery until either the LCM Rider captures it in 6 months or less, or until the time of the next base rate case. Mr. Blakely explained it is customary that if certain criteria are met, a utility may seek special authorization from the Commission to accrue carrying charges and defer depreciation, which benefits the utility's financial reporting. He stated when a utility requests post-in-service accounting treatment, it must demonstrate it will experience material earnings erosion; quantify this erosion as a percentage of total company earnings; and display the cost of the project or purchase as a percentage of net utility plant. Mr. Blakely testified that I&M provided no evidence of material earnings erosion, and therefore recommended the Commission deny I&M's request to defer and record as a regulatory asset the post-in-service depreciation, carrying costs and O&M expenses on the LCM sub-projects.

6. CAC's Evidence. John Athas, Principal Consultant and Treasurer of La Capra Associates, Inc., stated the purpose of his testimony was to evaluate and critique I&M's proposed LCM Project. More specifically, Mr. Athas explained that his focus was on I&M's IRP analyses, and stated that overall he does not believe that I&M's ratepayers should fund the LCM Project because I&M's IRP is "not robust enough." Mr. Athas further stated that I&M should consider and include in its IRP, issues and recommendations from the current Commission proceeding examining changes to the current IRP rule.

Mr. Athas stated he believed I&M did not do enough to address the requirements of the CPCN statute, even if such statute is not technically applicable to the LCM Project. Mr. Athas concluded that I&M's IRP is insufficiently detailed and he could not determine whether the investment in the Cook Plant is the best path and how the capital dollars were vetted in terms of other options the Company could have considered. He expressed his belief that the IRP was insufficiently robust to educate and inform stakeholders and to examine options that mitigate a full set of risks going forward. He argued that the IRP is insufficient to conclude that the utility achieved the goal of identifying a resource mix, including transmission assets that serve consumers in a cost effective manner.

Mr. Athas expressed concerns about the IRP in the area of fuel diversification, stating that I&M's fleet consists of 50% from coal-fired generation and 40% from the Cook Units, the combination of which is heavily weighted toward baseload generation. By way of comparison, he noted only 70% of PJM's capacity is baseload. He testified that overreliance on baseload may not allow the flexibility needed to accommodate intermittent, renewable resources. Mr. Athas questioned I&M's non-reliance on natural gas as an "ancillary" service, and questioned why I&M would pay for those ancillary services, instead of providing them itself. However, Mr. Athas also noted that in the Company's IRP, as several coal plants are assumed retired in 2014, their capacity is replaced by a combination of renewable assets, demand responses and energy efficiency. He also recognized that if Tanners Creek Unit 4 (a coal unit) is retired in 2024/2025, it is scheduled to be replaced by a natural gas combined cycle plant.

Mr. Athas further noted that in I&M's IRP, I&M considered replacing the Cook Units with a 607 MW gas fired combined cycle plant, and also considered seven 85 MW (total of 332 MW) gas-fired combustion turbines; however, the Company determined in its IRP that the LCM Project was the least cost-alternative compared to other replacement capacity options, even when using the "low gas price" scenario. However, Mr. Athas testified he believed that the price of natural gas will be even lower than that used in the Company's analysis.

Mr. Athas also stated that I&M used a conservative approach to energy efficiency in its IRP, but he would have preferred I&M make better use of sensitivity analysis for demand-side management ("DSM"), energy efficiency and load management to reduce the Company's load and capacity requirements. He stated this is especially relevant as I&M has proposed making a variety of upsizing investments. He acknowledged I&M determined such efforts would have an immediate impact on rates, but stated I&M could have included a sensitivity to show when DSM is no longer cost effective. Mr. Athas noted that I&M considered alternative resources in its IRP analysis, but dismissed renewable power, due to its intermittent output, as a viable option for replacing the quantity of baseload if the Cook Units were retired. Mr. Athas testified that merely dismissing renewable energy due to its intermittent nature is not normally accepted in IRP planning. He stated he believes I&M should have looked at other attributes of these alternative resources (such as regulatory benefits, renewable energy credit sales, and diversity benefits).

Mr. Athas concluded with comments on the Company's sensitivities in its IRP. Mr. Athas noted that some alternative assumptions (or "sensitivities") testing was included in the IRP. However, the Company did not perform any sensitivity analyses with respect to capital costs, O&M costs, potential increases in cost related to future safety regulations, or spent nuclear fuel disposal costs. He testified that while the benefits of the LCM Project under the Company's base case assumptions may be large, there did not appear to be any detailed analysis to support the assertion that the LCM Project would remain economic if additional costs were incurred in support of the Cook Units. Mr. Athas specifically recommended testing a variety of sensitivities around the potential for additional capital costs, carbon price, power prices, demand and natural gas combined cycle costs, and possibly "retrofitting" the Tanners Creek units.

7. I&M IG's Evidence. Nicholas Phillips, Jr., a public utility regulation consultant and Managing Principal of Brubaker & Associates, Inc., testified regarding the appropriate ratemaking associated with the LCM Project. Mr. Phillips testified that after reviewing I&M's testimony, he does not believe there is anything unique about the sub-projects that makes their tracking otherwise justified. The fact that Ind. Code ch. 8-1-8.8 mentions life cycle management does not change his recommendation because that term is not defined in the statute. In addition, under an expansive interpretation of the statute, he stated it is difficult to imagine any cost at the Cook Plant that I&M could not argue as qualifying. Mr. Phillips stated that if the legislature had intended this result, it could have done so in a clear and direct manner. Instead, Mr. Phillips indicated he believes the Commission retains discretion to implement Chapter 8.8 in a manner that is just and reasonable to all stakeholders.

Mr. Phillips testified the statute should not be used to track normal utility plant replacement costs and projects. Moreover, Mr. Phillips recommended the Commission limit the recovery through a tracker to individual sub-projects whose cost is material and substantial, to the extent they are otherwise recoverable under the statute. Specifically, he recommended the Commission not allow I&M to track sub-projects having individual costs of less than \$50 million, or \$20 million at a minimum. Mr. Phillips pointed out that trackers shift regulatory risk from I&M's investors to its customers; undermine the Commission's ability to evaluate the sufficiency of I&M's rates based on a totality of the utility's costs and revenues; and are not based on up-to-date data. He further recommended that if the Commission allowed tracking of any LCM sub-projects, I&M should also be required to file a retail rate case not less than every three years to ensure just and reasonable rates.

Mr. Phillips also recommended against permitting I&M to recover costs to facilitate an uprate that is not currently planned and may never be undertaken. Such expenditures are not required to maintain and operate the plant, Mr. Phillips explained, and would not be used and useful. Instead, Mr. Phillips recommended that I&M be permitted to request, in the appropriate proceeding, recovery of costs associated with a capacity uprate if one is performed.

In addition, Mr. Phillips recommended against permitting I&M to obtain preapproval of contingency costs, whether such costs are described as "management reserve" or "risk reserve." Instead, Mr. Phillips testified that if I&M exceeds its budget estimate on a project for which the Commission permits tracking treatment, I&M should be required to request an increase during a rider proceeding and the increased cost should be subject to a prudence review at that time.

Mr. Phillips testified that to the extent the Commission adopts any of the OUCC's proposals that would further limit the recovery of costs by I&M through a tracker, those proposals should be in addition to Mr. Phillips' recommendations. Mr. Phillips also objected to I&M's use of a forecasted cost tracking mechanism, as opposed to a tracking mechanism based on historical, incurred costs, particularly in the case of property taxes. He also argued against I&M's request for interim deferred accounting treatment, stating I&M has not shown any actual harm or demonstrated problems with current ratemaking in Indiana. In connection with his recommendation that I&M not be given authority to track lower cost projects, Mr. Phillips also recommended that I&M not be given authority to continue AFUDC or to defer depreciation on the non-tracked projects.

Finally, Mr. Phillips recommended the Commission specifically find that the Order issued in this case is not intended to maximize the return on I&M's investment in the Cook Plant. He argued that a reasonable return on prudent investment is a more appropriate standard for ratemaking.

8. I&M Rebuttal Evidence.

A. Paul Chodak, President and Chief Operating Officer of I&M. Mr. Chodak explained that I&M took issue with several of the OUCC's and Intervenor's positions. First, he stated that some of the witnesses' testimonies appear to reflect a misunderstanding or a disregard of the Indiana statute that explicitly authorizes timely cost recovery for reasonable and

necessary life cycle management projects that enhance the safe and reliable use of nuclear energy generation. For example, the I&M IG seeks to impose financial thresholds that are not present in the statute, and the OUCC seeks to limit the statute's application to mandated safety projects, which is likewise not supported by the statute. Mr. Chodak stated that the Indiana legislature has articulated a policy of encouraging and supporting nuclear life cycle management, and the Company's proposal is consistent with Indiana's policy and statute. He emphasized the proposed LCM sub-projects meet the industry definition of "life cycle management" and are necessary in order to safely and reliably operate the Units for their extended license periods. In fact, he noted, I&M's definition of "life cycle management" is stricter than the industry definition.

Additionally, while the LCM Project costs are significant, Mr. Chodak reiterated they are reasonable when compared to other alternatives for replacing the Cook capacity that would be lost if the Units were to be shut down. Related to this, he noted that it would be neither cost-effective nor realistic to retire the Cook Units and replace them with energy efficiency, renewables, and gas-fired generation. He testified the Cook Units have proven themselves to be a valuable source of capacity and energy for I&M and its customers in terms of reliability, availability, high capacity factors, and low energy costs, and I&M's resource planning analyses demonstrate the LCM Project investments are significantly more cost-effective than retirement and replacement of the Units.

Mr. Chodak urged the Commission to reject the OUCC's recommendations that the Commission approve the LCM sub-projects at the lowest end of the cost estimate ranges and exclude management reserve from the approved cost estimate. He stated the low end of the cost estimate ranges cannot be said to be the best or a reasonable estimate of sub-project costs, and the OUCC's recommendation is inconsistent with standard industry practice. With regard to the management reserve, Mr. Chodak emphasized that it is a form of contingency, and is the only contingency included in the LCM Project cost estimate.

Mr. Chodak testified that contingency costs are an appropriate and necessary component (and a standard practice) of a cost estimate for any major capital project. He stated the sub-project cost estimates do not contain any separate contingency or risk reserve, and any sub-project risk reserves must come from sub-project cost savings (as compared to estimates) or from the management reserve. Therefore, if management reserve were to be excluded from the LCM Project cost estimate, as urged by the OUCC, the Project cost estimate would contain no contingency, which would be unreasonable.

At the hearing, Mr. Chodak acknowledged that there was confusion earlier in the proceeding as to whether there was "risk reserve," in addition to management reserve, included in the filed LCM Project estimate, but emphasized that "it is crystal clear in our testimony as of this moment that when we filed, as filed all contingency dollars were in the management reserve pool." Tr. at A-42. He further characterized the debate over risk reserve versus management reserve as generally one of semantics: "whether you talk about known unknowns, risk reserve, management reserve . . . what we're talking about is contingency and the need for contingency in this Project, and that's all there is to it..." *Id.*; see also Tr. at A-46 thru A-47, A-66.

In explaining the need for contingency in a project cost estimate, Mr. Chodak emphasized that when one starts a project, particularly projects that are going to go over a course of six years, not every single thing is known – and some risks to the project are unknowable at the start of a project. For example, weather (such as hurricane) can impact labor costs. As another example, project scope can change in terms of discovering a problem – for instance, the need for a new impeller when you start a pump replacement project. Mr. Chodak distinguished this scope change from “scope creep” or “new scope” -- doing something completely different that had nothing to do with the objective of a project. Tr. at A-48 thru A-56, A-114.

Mr. Chodak also disagreed with the OUCC’s position concerning the Company’s decision to “upsized” several of the LCM Project components in order to preserve the option for a cost-effective extended power uprate in the future. Mr. Chodak also underscored the fact that all of the LCM sub-projects are being performed because they are necessary to extend the life of the Units beyond their forty-year design life; none of the sub-projects are directly related to a future power uprate. As such, he stated, they are appropriately classified as life cycle management and included in the LCM Project. He emphasized I&M’s strong belief that a decision to upsize these few life cycle management components now, at a relatively small incremental cost, is a reasonable business decision, given: the much larger cost that would be required to replace these components in the future if an uprate is implemented; the low operating cost of the Cook Units; the potential value of a power uprate; and the continuing uncertainty around federal environmental regulations, coal-fired plant retirements, and load growth.

With regard to the relatively small incremental cost of “upsizing” the seven sub-projects, Mr. Chodak noted that it is a prudent business practice to plan ahead. He stated if I&M failed to appropriately size these components now, to allow for a future uprate, it would cost I&M’s customers significantly more in the future if the Company pursues a power uprate. At the hearing, he explained that such incremental cost was approximately \$23 million, or about 2% of the overall Project cost. In contrast, he testified, the cost of replacing these sub-projects a few years later if a power uprate was pursued would be over \$100 million. Tr. at A-26, B-9, B-31.

As to the low operating cost of the Cook Units, Mr. Chodak testified at the hearing that the Units save customers about \$1.4 million a day currently, when compared to purchasing power on the market. Based on these operating costs, he estimated that a 400 MW uprate could save customers about \$93 million annually, as compared to a rough uprate cost estimate of about \$2,500 per kW. Although Mr. Chodak acknowledged I&M had not presented any evidence regarding the need for an uprate in the future, he testified “upsizing” these seven LCM sub-projects is justified to maintain the option for a future uprate – essentially as a “hedge” against future natural gas price increases, environmental regulation uncertainty, and load growth. Tr. at A-26 thru A-27, B-32.

Mr. Chodak testified the Company remains convinced that the Commission should approve the proposed LCM Project, including the timely recovery through rates of associated costs. He stated the Cook Plant has been providing reliable, low-cost energy for Indiana customers for years, and with the license extensions and these life cycle management investments, the Company should be able to continue to rely on the Cook Units for years to come. Mr. Chodak shared his belief that the LCM Project is both reasonable and necessary, the

Company's ratemaking and accounting requests are consistent with Indiana policy and statute, and the requested relief will allow I&M to maintain its credit quality, for the benefit of both the Company and its customers. Conversely, he stated, if either the OUCC's or the I&M IG's positions were adopted by the Commission, the financial impact on the Company would be significant.

B. John Torpey, Director - Integrated Resource Planning for American Electric Power Service Corporation. Mr. Torpey addressed CAC's comments regarding I&M's integrated resource planning and various assumptions and analyses used by the Company in support of its petition. He stated that Mr. Athas' concerns regarding the adequacy of I&M's IRP are not justified. Mr. Torpey testified that I&M conducted a thorough IRP process and it is clear from Exhibit 8-10 of the IRP that the Cook Plant is needed. Mr. Torpey stated, while Mr. Athas noted the Commission has proposed IRP rule changes, the proposed rules are not final, and therefore the Company's November 2011 IRP was not subject to them. The Company did not receive any comments from the Commission staff or other parties suggesting its IRP was not adequate. Mr. Torpey testified that I&M also provided evidence demonstrating the reasonableness and necessity of the LCM Project costs in accordance with the applicable statute. Mr. Torpey noted that, even though it is not required under the statute, the Company provided adequate explanations as to the concerns Mr. Athas raised relative to the requirements of a CPCN filing.

Mr. Torpey also disagreed with Mr. Athas' assumption that I&M needs a more diverse generating fleet, noting that I&M's generating fleet is already diverse in that it does not rely solely on only one source of fuel. He stated Mr. Athas' argument seemed to be based on an analysis that I&M is better off without the Cook Plant. Mr. Torpey noted, however, that I&M's fleet had capacity factors that ranged above 70% to above 90%. And, for the Cook Units specifically, during an 18-month period from January 2011 – June 2012, Cook Unit 1 had 14 months where its capacity factor exceeded 90%, including 4 months of 100% capacity factors; and Cook Unit 2 had 16 months where its capacity factor exceeded 90%, including 9 months where its capacity factor was 100%. Mr. Torpey concluded it is difficult to see how reducing the role of the Cook Plant in the Company's asset mix in order to achieve a goal of fuel diversity, and paying more as a result, would benefit customers.

Mr. Torpey explained that Mr. Athas' concern about the gas price forecast used by I&M in its IRP analyses is unfounded. Mr. Torpey explained the Company's gas price forecasts were revised downward since the early screening analysis was developed in 2011. The latest (lower) price forecast (circa November 2011) was used in the LCM Strategist[®] analysis developed for this case, and is in line with other consultant forecasts. Moreover, Mr. Torpey created a revised screening curve using natural gas prices provided by Mr. Athas, which is reflected in Petitioner's Exhibit JFT-R1. He stated the original analysis showed that the Cook Plant with the LCM Project was the preferred resource at capacity factors greater than 20%. The revised analysis shows Cook Plant with the LCM Project is the preferred resource at capacity factors greater than 21%. Even with Mr. Athas' lower natural gas prices, the analytical results are not materially different, and the LCM Project remains the superior option.

Mr. Torpey also responded to CAC's position that the LCM analysis should have included sensitivity analyses around carbon price, power price, demand and natural gas combined cycle costs. Mr. Torpey noted, while in other circumstances, CAC's position might have merit, in this case the evaluation performed by I&M overwhelmingly favors the LCM alternative. Mr. Torpey noted that Mr. Athas did not challenge I&M's actual analysis or its results. Mr. Torpey stated the LCM Project estimate used in the analysis includes appropriate funding for risks. In this case, the sensitivities that CAC believes the Company should have performed would merely be academic exercises and would not impact the final result - that the LCM Project is the lowest cost option for I&M's customers.

Mr. Torpey also addressed testimony from OUCC witnesses Keen, Sobel, and Lorton, and I&M IG witness Phillips, regarding incremental costs associated with "upsizing" several sub-project components that will allow the Cook Units to cost-effectively pursue an extended power uprate (capacity increase) in the future. Noting those witnesses recommend that timely recovery of the incremental cost of "upsizing" equipment be rejected, Mr. Torpey emphasized that Tanners Creek Unit 4's retirement date is uncertain and circumstances could require additional capacity sooner. In addition, he pointed out that the IRP does not select specific resources; rather it proposes the amount, timing and type of resource I&M should consider in the future. There are a number of scenarios (*e.g.*, environmental requirements, carbon regulation, a booming economy) that could lead the Company to consider an uprate of Cook instead of an alternative such as a natural gas combined cycle plant, and to consider it sooner rather than later. Having a cost-effective option to uprate Cook provides a hedge against commodity and construction costs, and maintains price pressure on suppliers. Alternatively, if the LCM equipment components are not "upsized," the option to add additional carbon free nuclear capacity will be significantly more costly.

C. Marc Lewis, Vice President, Regulatory and External Affairs. Mr. Lewis responded to testimony offered by IG witness Phillips and OUCC witness Keen concerning the statutory basis for timely recovery of the LCM Project costs. Mr. Lewis explained that those witnesses propose to exclude reasonable and necessary LCM Project costs from the approved cost estimate, in disregard of the clear intent of the legislature to encourage the timely recovery of life cycle management costs for nuclear generating facilities.

Mr. Lewis testified that in 2011, the Indiana General Assembly amended Indiana Code Chapter 8-1-8.8 to encourage nuclear power plant life cycle management by authorizing financial incentives for utilities with nuclear power plants undergoing life cycle management. Specifically, he noted that the legislature declared in Ind. Code § 8-1-8.8-1(a)(7) that, "[i]t is in the public interest for the state to encourage the study, analysis, development, and life cycle management of nuclear energy production or generating facilities...." Toward that end, the 2011 amendments expanded the definition of "clean energy projects" in Ind. Code § 8-1-8.8-2(1)(E) to include, "projects or potential projects that enhance the safe and reliable use of nuclear energy production or generating technologies to produce electricity." He noted that if the projects are found to be reasonable and necessary, Ind. Code § 8-1-8.8-11(a) provides that the Commission shall encourage such projects by creating certain financial incentives.

Mr. Lewis testified the Commission's consideration of I&M's request in this Cause should have at its foundation the public policy established by the Indiana General Assembly that supports life cycle management projects at nuclear generating facilities such as the Cook Plant. He further testified that the term "life cycle management" is a term of art in the nuclear industry, and that the plain language of the statute refers to "life cycle management" in terms of projects that enhance the safe and reliable use of nuclear energy power plants.

With regard to the OUCC's suggestion that in order to be eligible under Ind. Code § 8-1-8.8-11, the projects must be mandated by the NRC, Mr. Lewis pointed out that neither the NRC nor mandates are mentioned in this particular statute.

With regard to I&M IG witness Phillips' recommendation that the Commission limit the proposed LCM Rider to individual sub-projects that exceed \$50 million, or amount to at least \$20 million, Mr. Lewis noted there is no such limit in the statute. Additionally, he pointed out that it is well known that nuclear plant life cycle management involves investments in the billion dollar range, and the legislature did not limit the scope of the statute as Mr. Phillips recommends. He stated the statute was designed to encourage reasonable and necessary life cycle management projects, and not just reasonable and necessary projects that were also extremely large when considered individually. Moreover, he noted it was somewhat disingenuous for Mr. Phillips to suggest that a financial materiality threshold would not be met by the Company's proposal to invest more than \$1 billion in the safe and reliable operation of the Cook Plant.

In response to Mr. Phillips' contention that there is nothing "unique" about the LCM sub-projects that justifies cost tracking, Mr. Lewis testified there is nothing in the statute that indicates projects must be "unique" in order to qualify. Moreover, he stated, such a requirement would be counterintuitive; a number of nuclear power plants are seeking license extensions and undergoing life cycle management, so one would expect that the proposed projects would not be unique or one of a kind. However, Mr. Lewis did note that the proposed life cycle management capital investments are different from normal, ongoing capital investments at the Cook Plant, as is demonstrated by Petitioner's Exhibit MHC-8.

Mr. Lewis also responded to Mr. Phillips' criticism that one purpose of the LCM Project was to "maximize return on investment." Mr. Lewis explained that this phrase is part of the industry definition of "life cycle management," and simply refers to the goal of maximizing the value of the plant – in this case, for the benefit of customers. Mr. Lewis emphasized that the Company is not seeking a return on its LCM Project investment above the return authorized by the Commission, even though the statute allows for such a premium return.

With regard to the OUCC's position that the Commission deny I&M's requested relief because some of the LCM sub-projects are insufficiently safety related, Mr. Lewis explained that Section 11 of the statute applies to projects that enhance both the safety and reliability of nuclear power plants. Moreover, he pointed out that Section 12 of the statute applies even more broadly – to construction, operation and maintenance, and other activities.

On cross-examination, Mr. Lewis explained that, in his view, Section 11 uses the phrase "safety and reliability" as a descriptive term, not a term of limitation. Further, he believes the

phrase applies to the overall LCM Project, not to each individual component or sub-project. Thus, it is not necessary under Section 11 that each and every Project component or sub-project enhance both safety and reliability. Rather, the LCM Project as a whole must enhance the safety and reliability of the Cook Plant. Mr. Lewis also emphasized that certain cost components – such as indirect costs, AEP direct costs – are part of construction costs, not separate cost categories themselves. Finally, Mr. Lewis explained that Indiana Code Chapter 8-1-8.8 applies to projects on either the primary (reactor) or secondary (steam) side of a nuclear power plant, and beyond, which is illustrated by the statute’s application to transmission facilities and other associated equipment. Tr. at H-64; H-76; H-96 thru H-97.

D. Paul Schoepf, Director of Nuclear Projects at the Cook Plant. Mr. Schoepf responded to the OUCC’s and Intervenors’ testimony by discussing certain proposed sub-projects in greater detail and reiterating why those sub-projects meet the definition of “life cycle management” and why they are necessary for the continued safe and reliable operation of the Cook Units. Mr. Schoepf also addressed issues raised by the OUCC concerning the cost estimate and the proposed “upsizing” of certain LCM Project components. Finally, Mr. Schoepf rebutted the OUCC and Intervenors’ contentions that management reserve should be removed from the proposed LCM Project cost estimate.

With regard to the management reserve issue, Mr. Schoepf emphasized that management reserve is an accepted industry practice and a necessary and prudent project management tool for forecasting total project costs. He stated management reserve is a real project cost that is routinely forecast in construction projects and ultimately held for necessary cost growth due to unpredictable internal or external factors. As support for his statements, Mr. Schoepf pointed to both the Project Management Institute’s PMBOK, INPO’s “Excellence in Nuclear Project Management,” as well as documents from AACE and the American National Standards Institute. He also testified that the management reserve includes an allocation for indirect costs.

Mr. Schoepf testified that OUCC witness Keen misapplied the AACE definition for management reserve, incorrectly inferring that management reserve should not be included in an overall project estimate. Mr. Schoepf explained the AACE definition merely indicates that management reserve should not be included in the total defined scope and cost of each sub-project until it is actually allocated, because otherwise there would be an inaccurate calculation of the sub-project’s performance metrics. The management reserve cost amount should, however, be included in the total project cost estimate. According to Mr. Schoepf, management reserve, or contingency, is a necessary element of overall project cost. Absent the management reserve, the LCM Project cost estimate would contain no allowance for contingency.

With regard to the issue of whether all of the LCM sub-projects meet the industry definition of “life cycle management,” Mr. Schoepf reiterated the industry standard definition. He again noted that I&M has further qualified or limited life cycle management to non-recurring capital replacements required to operate the Units for their extended license periods. And to ensure that this more limited definition was implemented, I&M utilized a company nuclear asset management procedure (illustrated in Petitioner’s Exhibit MHC-8), detailed system health reports, and industry information to classify each LCM sub-project. Mr. Schoepf emphasized the LCM sub-projects as a whole are being performed for the sole purpose of fulfilling the extended

Unit operating licenses in a safe and reliable manner. He reiterated that the NRC does not prescribe or mandate life cycle management projects, but the NRC does require that a nuclear operator maintain its units in a safe and reliable condition.

Mr. Schoepf responded to the OUCC's testimony with respect to the proposed annunciator system and the Unit 2 turbine replacement sub-projects. With regard to the proposed annunciator system, Mr. Schoepf explained that the sub-project is not a "first of a kind," project and noted that another AEP plant has performed the same type of work. As to the Unit 2 turbine replacement sub-project, Mr. Schoepf disagreed with OUCC witness Sobel's characterization of the sub-project as analogous to the Vectren Dense Pack case and his recommendation that such sub-project costs should be recovered in the normal rate case process. Mr. Schoepf explained that the Unit 2 turbine replacement project is very different from the Vectren dense pack project where Vectren sought timely cost recovery for a turbine upgrade at a coal-fired plant as an "advanced technology" under a different statutory provision. In contrast, he stated, here recovery is being sought for a turbine replacement at a nuclear plant, under a statutory provision that specifically allows for special ratemaking treatment of nuclear power plant life-cycle management projects. Mr. Schoepf noted that the replacement of the Unit 2 turbine is an LCM project due to the condition of the Unit 2 turbine and emphasized it is being replaced for the sole purpose of fulfilling the extended unit operating life.

Mr. Schoepf also disagreed with OUCC witness Sobel's testimony that some of the sub-projects were not truly LCM projects. Mr. Schoepf explained, from an engineering perspective, all of the cited sub-projects are appropriately designated life cycle management projects and have clearly identified issues which, in the absence of the life cycle management activities, would affect their ability to meet the extended operation life. Further, he stated that all such sub-projects are one time capital projects that are critical structure, systems, or components that have aging and obsolescence issues or reliability issues. Mr. Schoepf addressed more specifically the following sub-projects: turbine and transformer replacements; Unit 2 GSU transformer spare; generator exciter projects; the drumming room HVAC, public address and technical support center projects; Unit 1 and 2 polar cranes; the switchyard line; ice condenser and annunciator systems; and the turbine room sump project.

Mr. Schoepf also responded to OUCC witness Sobel's testimony challenging I&M's cost estimating methodology. Mr. Schoepf stated the LCM Project estimate involves individual cost estimates that have been developed for each LCM sub-project in a bottom-up approach. He reiterated that the cost estimates from the EPC contractor were benchmarked by I&M and also by a third party, with some work being re-bid at a lower cost as a result. The sub-project cost estimates were also vetted through internal review boards to ensure accuracy. Mr. Schoepf also explained that the differences between the AEP and AREVA sub-project cost estimates are the result of the addition of indirect costs (*e.g.*, overheads) and I&M direct allocations (*e.g.*, I&M labor and staff support, third party review support, and installation oversight support). Mr. Schoepf also noted that there are no AFUDC costs included in the sub-project cost estimates. Mr. Schoepf further testified the AEP versus AREVA cost estimate comparisons are not of concern; only two sub-projects have an AEP cost estimate that is greater than 10% of the AREVA cost estimate (the main control room annunciator sub-project and the Unit 2 LP/HP feedwater heater sub-projects). Finally, Mr. Schoepf disagreed with Mr. Sobel's contention that

the AEP and AREVA cost estimates were prepared on the same basis and directly comparable. Rather, Mr. Schoepf explained that the AREVA construction cost estimate is based on benchmarking, and AREVA recognizes (through its risk discussions) that some of that benchmarking derives from different plant configurations and other material differences.

Mr. Schoepf also addressed the OUCC's concerns regarding a possible future power uprate – specifically, whether the incremental cost associated with “upsizing” several LCM Project components to preserve a cost-effective uprate option should be excluded from the approved LCM Project cost estimate. Mr. Schoepf testified that making a relatively modest investment now of \$23 million can save well over \$100 million later as compared to the cost to replace the equipment and systems again as part of a power uprate. The components involved in the upsizing are the same components already being replaced for the LCM Project, and were reviewed by the Company and concluded to be life cycle management projects in accordance with the relevant procedures summarized in Petitioner's Exhibit MHC-8. He noted that Petitioner's Exhibit PGS-R2 contains additional information on why these sub-projects must be completed as a part of the LCM Project. Mr. Schoepf confirmed that the sub-projects are being performed for the sole purpose of fulfilling the extended Unit operating licenses by safely and reliably extending the operating lives of Unit 1 and 2 through 2034 and 2037, respectively. Moreover, he noted that there are other benefits associated with “upsizing” these components – for example, the transformer size that is being proposed actually provides a cost savings because it is a more standard configuration than the custom size originally installed. In addition, the replacement of the heat exchangers with “upsized” heat exchangers will allow for improved plant performance due to design limits that will allow for a larger margin of tube pluggage before the Unit must be taken off line for maintenance. Mr. Schoepf confirmed that the design basis for these “upsized” components is to meet or exceed the license renewal extension periods for the two Units.

E. Scott Krawec, Director of Regulatory Services for I&M. Mr. Krawec addressed the ratemaking and accounting issues raised by the OUCC and Intervenors. First, Mr. Krawec addressed OUCC witness Blakley's concern that the LCM Rider will be “very large, complex and difficult to review.” Mr. Krawec noted that, although the LCM Rider will include a number of sub-projects, the proposed Rider is very similar in form and structure to environmental cost recovery riders already in place. Moreover, Mr. Krawec emphasized that I&M is committed to working with the OUCC and other parties to develop schedules and an audit package that allows for a thorough review to support the cost recovery of each sub-project. Mr. Krawec expressed confidence that, through collaborative efforts, the parties will be able to efficiently review and audit the LCM Rider reconciliation proceedings.

Next, Mr. Krawec responded to OUCC witness Blakley's concern that there could potentially be additional recovery on replaced equipment in base rates at the same time new equipment will be tracked through the LCM Rider. Mr. Krawec clarified that I&M's proposal mitigates this potential, by virtue of the Company requesting recovery of incremental depreciation expense, incremental property tax expense, and carrying charges for post-in-service equipment.

Further, Mr. Krawec expressed disagreement with OUCC witness Blakley's suggestion that the LCM Rider should be reduced by the amount of carrying charge on the remaining net book value of an equipment item being replaced. Mr. Krawec noted that when the replaced item is retired, the remaining original cost is transferred to the accumulated depreciation reserve account. This causes depreciation expense to decrease but there is no effect on net plant balances and, accordingly, no effect on rate base. And because rate base is unchanged by the retirement, it would not be appropriate to reduce the incremental carrying charge on the new asset as suggested by Mr. Blakely.

Mr. Krawec agreed with Mr. Blakley that in calculating the rate of return for the LCM Rider, only the return on equity should remain static from the last rate case, and that the cost of debt and capital structure should be updated to reflect current conditions. Mr. Krawec also confirmed that I&M's proposed LCM Rider does not seek recovery for any Project-related O&M expenses, and that, accordingly, there is no potential for double recovery of O&M expenses. In response to Mr. Phillips' concern that the Company might include property tax expense in the LCM Rider before any property taxes have actually been assessed, Mr. Krawec clarified that I&M proposes to recover the incremental difference between the property tax expense on the new equipment and the property tax expense on the replaced equipment. But, he explained, that difference would not be reflected in the LCM Rider until the time the new asset is recognized and the old asset is removed for property tax expense purposes.

Mr. Krawec also responded to witnesses Blakley and Phillips' recommendations that the Commission deny I&M the requested interim deferred accounting treatment. He noted that Ind. Code Chapter 8-1-8.8 specifically provides for timely cost recovery for these types of projects, and that interim accounting relief is necessary to facilitate full and timely recovery. In other words, the interim deferred accounting relief and the LCM Rider are related to, and both support, the overall statutory authorization for timely recovery of life cycle management costs. Mr. Krawec distinguished the two cases cited by Mr. Blakely in support of his position, noting that neither of the cited cases pertained to relief afforded by Ind. Code Chapter 8-1-8.8. Further, Mr. Krawec addressed the alleged lack of harm by explaining why I&M will experience significant earnings erosion if the relief requested by the Company is denied. He estimated that I&M would experience more than \$8 million (or 6.49%) and \$17 million (13.67%) in Indiana jurisdictional after tax earnings erosion in 2013 and 2014, respectively, if the requested relief were denied. And he emphasized that this earnings erosion would negatively impact the Company's credit quality at a time when I&M is facing substantial financing for the LCM Project as well as for environmental retrofits at other plants. Finally, he pointed out that I&M was not earning its authorized net operating income.

Mr. Krawec also disagreed with OUCC witness Keen's recommendation that certain sub-projects be recovered under separate, traditional cost recovery mechanisms. Mr. Krawec noted, from a ratemaking point of view, this recommendation would not allow for timely cost recovery of the LCM Project costs. He noted that general rate cases have to be filed at least 15 months apart, that processing rate cases typically takes a year or more, and that the LCM sub-projects have staggered in-service dates over the next several years, making it impossible for I&M to fully and timely recover its LCM Project costs through base rate case treatment.

Finally, Mr. Krawec took issue with Mr. Phillips' recommendation that, if the Commission approves the Company's LCM Rider, the Commission should also require the Company to file another base rate case. He noted that I&M received a base rate order in March 2009 and had another case pending, making any rate case filing requirement unnecessary.⁹

F. Jack Roe, Jr., Consultant for Scientech. Dr. Jack Roe, a consultant with over 30 years of experience in the design, construction, operation and regulation of nuclear power plants, including service in the U.S. Navy, the NRC, Scientech, and the Nuclear Energy Institute, responded to the OUCC's and Intervenor's testimony concerning NRC regulation of nuclear power plants, the definition of "life cycle management," the application of that definition to I&M's LCM sub-projects, the NRC's Maintenance Rule, the definitions of "safety" and "reliability" in the context of nuclear power plant regulation, and the potential for a future extended power uprate at the Cook Plant.

Dr. Roe first gave an overview of how the NRC regulates U.S. nuclear power plants. He explained the NRC's regulatory process has 5 main components: (1) developing regulations and guidance for applicants and licensees; (2) licensing or certifying applicants to use nuclear materials or operate or decommission nuclear facilities; (3) overseeing licensee operations and facilities to ensure that licensees comply with safety requirements; (4) evaluating operational experience at licensed facilities; and (5) conducting research, holding hearings, and obtaining independent reviews to support regulatory decisions. The key components of the NRC's regulatory program are: regulations and guidance; licensing; oversight; and operational experience.

Dr. Roe testified the NRC's primary focus is to ensure the adequate protection of public health and safety, promote the common defense and security, and protect the environment. The NRC's focus on safety includes the reliability of power plants, which is addressed in the NRC's Maintenance Rule. Dr. Roe stated the NRC's requirements for nuclear power plants are applied in a variety of ways, as is demonstrated by the NRC's "current licensing basis."

Dr. Roe testified that he defines "life cycle management" within the context of nuclear power plants as follows:

The integration of aging management and economic planning to optimize the operation, maintenance, and service life of structures, systems and components (SSCs); maintain an acceptable level of performance and safety; and maximize return of investment over the service life of the plant.

Pet.'s Ex. O at 11. He noted that his definition is the same as the standard industry definition found in "NEI Industry wide Process Description Nuclear Asset Management SS002 NEI AP-940 Rev. 0 May 2005," as well as the definition contained in Mr. Carlson's testimony and in Mr. Sobel's testimony. He explained the purpose of a life cycle management process at a nuclear power plant is the timely detection and mitigation of aging effects in SSCs that are important to plant safety, reliability, and economics. He stated that life cycle management is also a process used to meet regulatory requirements for license renewal and maintenance.

⁹ The Commission issued an order in the pending rate case, Cause No. 44075, on February 13, 2013.

Dr. Roe testified he reviewed all 117 of I&M's proposed LCM sub-projects, and in his opinion, all of these sub-projects are "life cycle management" projects within the meaning of the industry definition. He stated the sub-projects address: aging management and economic planning to optimize the operation, maintenance, and service life of SSCs; maintenance of an acceptable level of performance and safety; and maximizing the return of investment over the service life of the plant. He agreed with Mr. Schoepf that the collection of sub-projects is being performed for the sole purpose of fulfilling the extended unit operating licenses by safely and reliably extending the operating lives of Cook Units 1 and 2 through 2034 and 2037; that the LCM Project would not be done if the operating licenses had not been extended; and that all of the LCM sub-projects are necessary in order for the Cook Units to safely and reliably continue operating for the extended license periods. He stated that nuclear power plant life cycle management is focused on both safety and reliability.

Dr. Roe explained the NRC has two major regulations related to life cycle management activities: license renewal and the Maintenance Rule. Further, the NRC has two categories of rules – prescriptive rules and performance-based rules. Many NRC regulations are prescriptive and provide detailed requirements for the licensee. The Maintenance Rule, however, is a performance-based rule, and provides a process to use as opposed to detailed prescriptive requirements. The Maintenance Rule has 4 main areas: goal setting and monitoring; preventive maintenance; periodic evaluation; and safety assessments before performing maintenance. Dr. Roe stated the Maintenance Rule includes both safety-related and non-safety related SSCs, as follows: (1) safety-related SSCs that are relied upon to remain functional during and following design basis events to ensure the integrity of the reactor coolant pressure boundary, the capability to shut down the reactor and maintain it in a safe shutdown condition, or the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure; (2) non-safety related SSCs (i) that are relied upon to mitigate accidents or transients or are used in plant emergency operating procedures; or (ii) whose failure could prevent safety-related SSCs from fulfilling their safety-related functions; or (iii) whose failure could cause a reactor scram or actuation of a safety-related system. Thus, Dr. Roe testified, the Maintenance Rule is considered a safety rule as proper maintenance is essential to plant safety.

Dr. Roe expressed agreement with I&M's definition of "safety" for purposes of life cycle management, but disagreed with OUCC witness Sobel's definition. He concluded that I&M's definition correctly describes the NRC's and the industry's understanding of nuclear safety with respect to the operation of nuclear power plants, and is consistent with the Maintenance Rule. Mr. Sobel's definition, on the other hand, is inconsistent with the Maintenance Rule and does not reflect the regulatory requirements for the maintenance of operating nuclear power plants. Dr. Roe stated I&M must meet both the NRC's license renewal rule and the Maintenance Rule. Dr. Roe also disagreed with OUCC witness Sobel's statement that "I&M may have included sub-projects that are not safety driven in the LCM Project." Dr. Roe pointed out that Mr. Sobel based that statement on an incomplete definition of safety that does not reflect the NRC's Maintenance Rule.

Dr. Roe also responded to the OUCC's concern regarding I&M's decision process to determine whether or not to include sub-projects in life cycle management. Dr. Roe testified that

he reviewed I&M's flowchart that was used to determine whether a sub-project should be included, and believes it is an accurate management tool to determine whether a project is a life cycle management project, as opposed to ongoing capital or O&M. He stated the flowchart properly addresses regulatory functions (including the Maintenance Rule); capital; structures, systems, and components; equipment reliability process component classification; aging/obsolescence; unit reliability for license extension; and one-time projects.

Dr. Roe also took issue with OUCC witness Sobel's concern regarding the future uprate possibility, and I&M's inclusion of "upsized" components to preserve a cost-effective uprate option in its LCM Project. Dr. Roe stated that, in his view, I&M can reasonably expect to obtain NRC approval to implement an extended power uprate at a nuclear power plant when they have met the regulatory requirements. Further, he explained that from his perspective and assuming there is a possibility that capacity from a future uprate will be cost-effective and needed, the Company's decision to upsize the components is a wise decision, in terms of increasing the safety margin of the components, as well as avoiding duplicate replacement costs in the future.

Dr. Roe also disagreed with OUCC witness Sobel's opinion that the Unit 2 turbine replacement sub-project should not be included in I&M's LCM Project. Mr. Roe stated he believes the Unit 2 Low Pressure Turbines and the High Pressure Turbine replacement sub-projects do qualify as life cycle management because the turbines are approaching the end of their service lives and require replacement. He also emphasized that, while not technically a safety-related component, the turbine plays an important part in nuclear safety. For example, it is a non-safety component that is covered by the Maintenance Rule because it is a component whose failure could cause a reactor scram (*i.e.*, a rapid shutdown of a nuclear unit) or actuation of a safety-related system. The failure of a turbine can cause damage to plant equipment and injury to plant workers. Moreover, Dr. Roe explained that the NRC is specifically interested in turbine safety and reliability. The NRC does not want a turbine failure and has provided guidance on protection from turbine missiles (*i.e.*, turbine parts ejected upward through the turbine casing, potentially causing damage to plant components and/or plant staff).

G. Daniel Denver, Consultant for Sciencetech. Mr. Denver, a project manager and consultant with mechanical and nuclear engineering degrees and extensive experience managing projects, including projects at nuclear power plants, provided rebuttal testimony concerning the reasonableness of I&M's LCM sub-project cost estimates and their confidence levels, as well as the proposed use of risk and management reserve on these sub-projects.

Mr. Denver provided an overview of authoritative cost estimating sources, discussed the concept of uncertainty in project cost estimates, and then discussed I&M's LCM Project estimate in particular. He testified that the individual I&M cost estimates for each LCM sub-project were developed in accordance with industry standard cost estimating guidelines. Empirical data, benchmarking, statistics, and environmental considerations were used throughout the estimating process to maximize the accuracy of the estimates.

He noted that, in general, the cost estimates were developed separately in a bottoms-up approach and vetted by plant review processes. In addition, some sub-project estimates were benchmarked with other organizations and some estimates were developed and/or reviewed with

third party reviewers or vendors. He noted that the sub-project cost estimates are included in internal management reviews and approvals. He also stated that fully two-thirds of the total LCM Project cost estimate is comprised of 32 sub-projects (“Shaw estimates”) that were part of the development and estimating work done by a well-respected EPC contractor, Shaw Nuclear Services, in preparing the DC Cook Phase 1 Report dated November 2010. He also noted the cost estimates for the smaller sub-projects (*e.g.*, less than \$500,000) were derived from subject matter experts with and without the benefit of vendor estimates, both of which were equally valid ways of developing acceptable cost estimates for projects of this magnitude.

Mr. Denver opined that I&M’s use of phases, with different cost estimate accuracies, is reasonable and consistent with industry standards. Mr. Denver noted that, as expected, estimate accuracy improves with project definition and engineering or design progress; these attributes are both intuitive and consistent with industry literature on cost estimation. He testified that I&M’s use of project phases based on percent of project definition (or maturity) aligns with the industry standard as best documented in the AACE guidelines. Mr. Denver noted that AACE is internationally the most recognized organization supporting the project management industry with standards, guidance and training related to cost management.

He testified it is not only reasonable, but expected, that some Phase 1 sub-projects have cost estimate accuracies of +/-50%. That said, he also emphasized none of the sub-projects are first-of-a-kind, and the sub-projects implement modifications that are routine at power plants such as D.C. Cook. Thus, even in the early project phases where project definition is lower, there is still high confidence in the estimates.

He also strongly disagreed with the OUCC’s recommendation that the Commission approve the lower end of the sub-projects’ cost estimate ranges. In his view, arbitrarily limiting the resources available to the Project to the lower bound estimate could constrain the project manager to seek cheap, quick fixes to what are often complex problems encountered during a project. He stated experience tells us this is not a prudent course of action. If the project manager lacks sufficient resources to complete project objectives and deal with unexpected changes in project assumptions, then it is almost certain the project will fail to meet its objectives.

Mr. Denver concluded that, in his opinion, I&M’s cost estimating practices are consistent with both industry standards and practices at comparable power stations and other nuclear industry facilities. I&M’s rigorous project management procedures and practices ensure consistent application of these principles across the sub-projects and allow management to impose consistent expectations across the organization. Accordingly, Mr. Denver opined that I&M’s cost estimates for the LCM sub-projects are reasonable.

Mr. Denver also addressed issues related to contingency and management reserve. Mr. Denver noted that contingency is one of the main tools for managing the uncertainties in a project. AACE International Recommended Practice 10S-90 defines contingency as “[a]n amount added to an estimate to allow for items, conditions or events for which the state or occurrence or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs.” Thus, he stated, it is simply funds or schedule time added to a project’s

estimate to reduce the risk of running out of money or time before the project's objectives are met. Mr. Denver went on to clarify that risk reserve, often called contingency reserve, is project funding for "known unknowns." This funding is for risks that have been identified, but their impact to the project is unknown, such as inflation risk or direct or indirect weather delays that affect project implementation. Often, however, an estimate of these risks can be made by benchmarking to similar projects, expert judgment or other similar methods. The risk reserve is usually included as part of the project baseline and is managed by the project manager. In contrast to risk reserve, management reserve is funding for "unknown unknowns" encountered in the project and is usually managed by senior management.

Mr. Denver stated his understanding was that the only contingency included by I&M in the LCM Project estimate is the management reserve, and therefore the total sum of management reserve and risk reserve is about 20% of total LCM Project cost, which is adequate (although not overly generous) considering the scope and complexity of the LCM sub-projects. He stated that he performed a simple analysis, ignoring the diversity in having 117 sub-projects, and concluded that a contingency of about 33% could be justified for the total LCM Project.

Mr. Denver emphasized that contingency, whether it is defined as a "risk reserve" or "management reserve" is a "real" cost that should be included in a project cost estimate. The nature of projects is that they are complex undertakings and their costs cannot be estimated precisely until the project nears completion. He stated the need for contingency funds is real and expected; therefore, contingency in some form (either as risk or management reserve) is needed to deal with these variances and must be a part of the overall project estimate and funding.

Finally, Mr. Denver discussed I&M's project controls, noting that I&M has in place various project cost control methods and structures. He stated I&M monitors ongoing projects by both line management and various review boards on daily, weekly, monthly and quarterly intervals. I&M also uses elaborate formal project approval and management processes, which includes a number of management review committees, each with a defined responsibility to approve and monitor projects costing greater than \$500,000. Moreover, I&M's independent Project Controls group provides control and oversight of the LCM sub-projects, including measuring performance based on earned value and progress against milestones. Should a sub-project exceed its estimated cost, he noted there are processes in place that require further justification from the project's sponsor and project manager; that process requires further approvals from project management, Cook senior management, and corporate management if a Capital Improvement requisition revision is needed. In Mr. Denver's opinion, taken together, these processes impose sufficient rigor so that project overruns are not taken lightly. Mr. Denver concluded that I&M's project cost control method and structures are reasonable and consistent with industry standards.

9. OUCC's Supplemental Testimony. Mr. Keen responded to I&M's supplemental and rebuttal testimony. He first addressed Mr. Schoepf's "adoption" of Mr. Brown's testimony with changes. While Mr. Brown's original testimony stated that risk reserve is included in the funding in each project, Mr. Schoepf's testimony stated that I&M did not include risk reserve contingency as a separate cost in each sub-project. Mr. Keen noted the new testimony also contradicted prior I&M representations. Referring to Mr. Chodak's statement that any "sub-

project risk reserves must come from sub-project cost savings (as compared to estimates) or management reserves,” Mr. Keen testified that the OUCC remains convinced that within each sub-project estimate there are sufficient funds identified to complete the Project, making the inclusion of management reserve unjustifiable. Mr. Keen also noted that I&M’s position regarding contingency changed similarly during its proceeding before the Michigan Public Service Commission.

Mr. Keen also expressed the OUCC’s concern with the contingency in the cost estimate because I&M took the Shaw estimate, removed contingency, and then added in “indirect costs” without defining what is included in indirect costs. Further, Mr. Keen stated the OUCC is concerned about the transparency of the LCM Project, in part, because it would be nearly impossible to track discrete sub-project costs as they increase or decrease. Without effective tracking of costs, there is little incentive for I&M to manage the project in a prudent manner. Mr. Keen also took issue with I&M’s responses to discovery requests for cost estimates, noting that I&M was unable to produce detailed costs for each sub-project, including indirect and contingency costs for completed and closed sub-projects. Mr. Keen also expressed concern with I&M’s approach because it affords no way to track fund movements between sub-projects, providing no audit trail for the Commission or interested parties to track any funding exchanged between sub-projects. He stated the lack of transparency is not in the best interests of the ratepayer and should be rejected. In conclusion, Mr. Keen stated the OUCC remains confident in the reasonableness of its earlier recommendations.

10. I&M’s Supplemental Rebuttal Testimony.

A. Paul Chodak. Mr. Chodak addressed Mr. Keen’s testimony concerning his characterization of contingency (risk reserve and management reserve) for the LCM Project. Mr. Chodak indicated that, in hindsight, he could understand how someone not participating in the LCM Project could misinterpret that risk reserve was included in each sub-project cost estimate as a distinct upfront cost. He noted I&M’s case-in-chief testimony discussed both the concepts of risk reserve and management reserve, and discussed how each was an important component of project contingency. While both risk reserve and management reserve were discussed as general topics, the case-in-chief identified that management reserve was included in the LCM Project cost estimate. Further, both Mr. Schoepf’s direct testimony, as well as I&M’s rebuttal testimony and later discovery responses, clarified that the intent was to state that no risk reserve was included in the upfront sub-project cost estimates filed with the Commission. That fact, Mr. Chodak stated, seems to have been misinterpreted to mean that risk reserve would not be funded later within the costs originally filed with the Commission – including using an allocation of management reserve if needed.

Given the static/snapshot nature of a regulatory proceeding, versus the ongoing/evolutionary nature of actual project management, Mr. Chodak indicated it is understandable that this misunderstanding occurred. He explained that, at the time the initial sub-project cost estimates were developed, I&M did not include any risk reserve in those sub-project cost estimates. He further noted I&M removed contingency at the sub-project level from the Shaw estimate. Thus, the Company’s April 2012 case-in-chief filing reflected sub-project cost estimates without any risk reserve. However, he stated, the Company’s case-in-chief filing

did include an overall management reserve amount of \$200 million (\$220 million with indirect costs included). This management reserve amount was intended to deal with the cost of any uncertainty around the projects that could not be known until installation events begin.

Mr. Chodak explained the filed “point in time” cost estimate for a particular sub-project may be different than the current estimate due to ongoing project management of the sub-projects. Project management, he noted, continues on a daily basis. This evolutionary process involves moving through the project phases, gathering more information, identifying risks, quantifying those risks, and refining sub-project cost estimates until the sub-project is placed in-service. He stated that although I&M began compiling risk registers for sub-projects as early as the end of Phase 1 or beginning of Phase 2A, such risk registers, including quantification and funding of identified risks, are not finalized until Phase 3 when installation events begin and issues are more likely to be identified and encountered.

With regard to risk reserve in particular, Mr. Chodak stated that as I&M moves through the project phases, it will identify and quantify risks. As that occurs, I&M will include and ultimately fund risk reserves in the sub-project cost estimates. The funding for these risk reserves will come from one of three sources: (1) savings in other aspects of the particular sub-project; (2) savings “harvested” from other sub-projects; or (3) the management reserve. Mr. Chodak testified that I&M has been conservative in its methodology for funding such risk reserves for this LCM Project.

Mr. Chodak emphasized that risk reserves are an important part of I&M’s “project management” of the LCM Project as the sub-projects progress, but were not given any numerical value as part of the “cost estimate.” He stated risk reserve values were not included in the initial sub-project cost estimates both because (1) there was not enough information at the time to identify or quantify the specific risks for almost all of the sub-projects, and (2) he felt a 20% management reserve would be adequate compared to the higher cumulative amount of risk reserve that would be called for under industry guidelines for the phases of each sub-project at the time of filing the case-in-chief. As sub-projects progress through the phases, and in particular in Phase 3, I&M will complete identification of risks and associated funding of risk reserves, but not as new costs for the estimate, just movement of costs already presented.

Mr. Chodak explained that regulatory proceedings focus on a certain “snapshot” in time, which does not necessarily provide a full and complete picture of active project management. He noted the LCM sub-projects have progressed significantly in the eight months between I&M’s case-in-chief and its supplemental rebuttal filings. For this reason, Mr. Chodak stated, I&M believes its proposal of an ongoing review process for the LCM Project is reasonable and will be useful to the Commission and the participating parties. Project management is a dynamic, ongoing and evolutionary process, and it does not easily lend itself to litigation at an arbitrary point in time. Mr. Chodak stated he believes the Commission has sufficient information in this proceeding to determine (1) whether the LCM Project is “necessary” in order to keep the Cook units operational for another twenty years, and (2) whether the LCM Project’s estimated cost is “reasonable” in light of other resource alternatives, the development of the cost estimates and the level of management reserve contingency. Further, the proposed ongoing review process will provide an opportunity to review and monitor management of the LCM

Project as each of its sub-projects progresses through the various phases to completion, including scrutiny of any changes to sub-project cost estimates and the reasons for such changes, any changes to the LCM Project cost estimate, and any uses of the management reserve.

Mr. Chodak concluded that, while the apparent misinterpretation about whether risk reserve contingency was or was not included in the initial sub-project cost estimates versus the ongoing “project management” of the sub-projects is unfortunate, this misunderstanding in no way renders the management reserve unnecessary or the overall Project cost estimate unreasonable.

Mr. Chodak strongly disagreed with the OUCC’s contention that within each sub-project estimate there are sufficient funds identified to complete the projects. He testified each sub-project cost estimate was developed as a “best” estimate, given the information known at the time, and using acceptable cost estimating techniques. Each sub-project cost estimate was developed based on the scope known at that time. He stated if an opportunity for a more cost advantageous and acceptable solution can be found, I&M will choose to act on it. If that occurs, and savings can be achieved, those savings will benefit customers, by virtue of either funding other risk reserve items instead of accessing the management reserve or by virtue of not being spent and included in rates. He said the Commission should not “short” I&M’s overall cost estimate in speculative anticipation that savings will materialize because it is simply incorrect to equate the potential for a sub-project to come in under budget with a layer of contingency. If the OUCC’s position were to be adopted, he stated there would be no contingency included in the LCM Project cost estimate, which would be unreasonable. While I&M will certainly strive to keep Project costs as low as reasonably possible, including funding risk reserves out of sub-project savings to the extent possible, Mr. Chodak stated it is likely the Project will need to access the management reserves at some point in the future.

Mr. Chodak testified that the OUCC’s position appears to have the perhaps unintended consequence of punishing I&M for its rigorous cost control focus and its industry standard approach to including contingency in the Project cost estimate. Project management experience shows that some projects will come in over their estimates, some will come in under, but not every project will be over, and not every project that is over will be +50% or even +25%. Given that the LCM Project is comprised of 117 sub-projects, not just one or two sub-projects, Mr. Chodak expressed confidence that this diversity of projects will come in much less than at a +50% level. For these reasons, he stated, I&M concluded that a relatively conservative overall contingency amount of approximately 20% was reasonable, and consequently \$200 million (\$220 million with indirect costs) was included in the Project cost estimate as management reserve.

Mr. Chodak also addressed Mr. Keen’s assertion that management reserve should be excluded from the Project cost estimate because the AACE definition of management reserve provides that such reserves are for purposes “outside of the defined scope of the project.” He stated that the OUCC appears to be confused. He explained it is important for cost control purposes to keep potential scope changes out of a project’s baseline cost estimate, so that actual project performance can be judged accurately. If a scope change is approved by senior

management, per the PMBOK guidelines, it is then added to the project's baseline cost estimate. This by no means implies, however, that management reserve should not be included in an overall project cost estimate. Contingency, whether in the form of risk reserve, management reserve, or some combination of the two, is an essential element of any major project cost estimate.

Mr. Chodak also took issue with Mr. Keen's statements that "the inclusion of indirect costs is itself a layer of contingency," and that "the Company has not provided any explanation of what is included in indirect costs." He emphasized that indirect costs are real costs incurred by every project that are intended to account for the cost of construction overhead allocations, not for contingency purposes. Construction overhead allocations includes those costs related to construction, but not directly applied to a given construction project. These costs consist of certain administrative, supervisory, engineering, and stores costs that cannot be classified directly to projects without undue burden and refinement. Thus, the costs are allocated to construction based on total current month charges to a project before it is applied.

B. Paul G. Schoepf. Mr. Schoepf addressed the supplemental testimony of OUCC witness Keen concerning "Project Management" methodology and transparency. Mr. Schoepf stated he believes the documentation and methodology laid out by I&M will provide a third party with the ability to review the LCM Project in detail. He stated I&M shared the methods that were used to develop sub-project estimates as well as the methods that will be used to document actual sub-project costs and any changes in scope or sub-project schedule. Mr. Schoepf also noted that a change in the scope of a project warrants using a PCRf as a documentation method; it is a simple form, and the industry standard for the purpose of having an auditable trail.

On redirect examination, Mr. Schoepf emphasized that the Company has processes in place to track the movement of dollars, should such occur, between sub-projects. He explained that a formal auditable trail will exist for those types of transfers between sub-projects. Among other things, his signature and the signatures of the project manager, project controls manager, and project sponsor are required, and retained for auditors, and will be available in the ongoing review proceedings. Mr. Schoepf reiterated that the Company is committed to providing the Commission with a transparent ongoing review process. Tr. at F-58 thru F-63.

Mr. Schoepf also noted that he had addressed transparency in his direct testimony, where he described the consistent, ongoing, and auditable process and associated metrics for tracking the progress of each sub-project over \$500,000. Mr. Schoepf also referenced other parts of his previous testimony that addressed transparency, including describing the process which will govern the use of management reserve and the various approvals required, ultimately concluding that I&M's documentation methods demonstrate the transparency and ability to audit any changes in project scope, cost, and schedule for third party review. As additional support for the auditability of the Project, Mr. Schoepf noted that AEP's internal auditing department recently completed an internal audit of the LCM Project. The objective of the audit was "to evaluate the design and test the effectiveness of controls associated with contract administration and project management related activities." Pet.'s Ex. J at 12. AEP's internal audit department was able to

complete their audit, and they found that in the areas within the scope of the audit, the Project was well-controlled.

Mr. Schoepf also took issue with Mr. Keen's questioning of I&M's response to data requests concerning detailed cost analyses. Mr. Schoepf argued that Mr. Keen appears to have misunderstood part of the Company's response. He said I&M has detailed costs for completed and closed sub-projects which allow participating parties and the Commission to track and audit project management. Due to the large data request from the OUCC, it would have been overly burdensome to provide the detailed cost breakdown requested by Mr. Keen. However, I&M did provide the overall estimate for the noted categories, and he noted that at a 2-day conference held on November 19-20, 2012, the OUCC was provided with details for a focused group of active and completed sub-projects. These details were provided to the OUCC in multiple binders for review. The Company also made available several Cook Plant project management personnel to answer any questions the OUCC might have on the projects.

11. Commission Discussion and Findings. I&M seeks Commission approval of its LCM Project as a reasonable and necessary "clean energy project" eligible for financial incentives, including the timely recovery of certain associated costs pursuant to Ind. Code ch. 8-1-8.8. Although I&M's Petition indicates relief is also being sought under Ind. Code § 8-1-2-23 (additions and expansions); Ind. Code §§ 8-1-2-10, -12, and -14 (utility books and accounts); Ind. Code § 8-1-2-42(a) (rate changes); and, Ind. Code §§ 5-14-3-4 and 8-1-2-29 (public records), none of these provisions is disputed among the parties.

Instead, the parties have focused their disputes primarily as it concerns the application of Ind. Code ch. 8-1-8.8 ("Chapter 8.8"). The primary issues among the parties include the following: (1) whether the LCM Project should be reviewed as one project or multiple individual projects; (2) whether some or all of the LCM sub-projects are clean energy projects eligible for financial incentives; (3) the sufficiency and reasonableness of the estimated costs and expenses for some or all of the LCM sub-projects; and (4) I&M's proposal to base its retail rate adjustment mechanism on forecasted data.

Unfortunately, Chapter 8.8 contains several provisions that are unclear and ambiguous, which has fueled the disputes among the parties that we must resolve in considering I&M's requested relief. In resolving those disputes, we are guided by some general principles of statutory interpretation. In construing a statute, the primary goal is to determine and give effect to the intent of the Legislature. *Ind. Civil Rights Comm'n v. Alder*, 714 N.E.2d 632, 637 (Ind. 1999). When the statute is clear and unambiguous, we need not apply any rules of construction other than to require that words and phrases be given their plain, ordinary and usual meanings. *City of Carmel v. Steele*, 865 N.E.2d 612, 618 (Ind. 2007). However, when a statute is ambiguous, sections of the statute should be read together so that no part is rendered meaningless if it can be harmonized with the remainder of the statute. *Ind. Dept. of Pub. Welfare v. Payne*, 622 N.E.2d 461, 466 (Ind. 1993). We do not presume that the Legislature intended language in a statute to be applied illogically or to bring about an unjust or absurd result. *City of Carmel*, 865 N.E.2d at 618.

A. Statutory Framework. In 2011, the Indiana General Assembly determined it to be "in the public interest for the state to encourage the study, analysis, development, and life

cycle management of nuclear energy production or generating facilities,” and enacted legislation designed to ensure such activities are encouraged. Ind. Code § 8-1-8.8-1(a)(7) and (b)(5). To encourage this investment, Ind. Code 8-1-8.8-11 (“Section 11”) requires the Commission to determine whether a “clean energy project” is reasonable and necessary so as to be eligible for certain financial incentives. If the Commission makes such a determination, Ind. Code § 8-1-8.8-12 (“Section 12”) requires the Commission to provide financial incentives to the “eligible business” if it provides substantial documentation that the expected costs and schedule for incurring those costs are reasonable and necessary. If a project is approved, the Commission has the authority under Ind. Code § 8-1-8.8-15 (“Section 15”) to review it as necessary to ensure compliance and may revoke any incentives for non-compliance.

1. Section 11. As noted above, Section 11(a) requires the Commission to encourage clean energy projects through the creation of certain financial incentives if the projects are found to be reasonable and necessary. As relevant to this case, the Legislature in 2011 amended the definition of clean energy project to include both “[p]rojects to provide electric transmission facilities to serve ... a nuclear energy production or generating facility” and “[p]rojects or potential projects that enhance the safe and reliable use of nuclear energy production or generating technologies to produce electricity.” Ind. Code § 8-1-8.8-2(1)(C) and (E). Section 11(b) requires an eligible business to file an application with the Commission for approval of such a project. After submission and review of an application, the Commission is required to issue a determination of the project’s eligibility for the financial incentives. Ind. Code § 8-1-8.8-11(d).

Therefore, in order for the LCM Project to be eligible for the specified financial incentives, Section 11 requires the Commission to determine that:

1. I&M is an eligible business;
2. the LCM Project is a clean energy project; and
3. the LCM Project is reasonable and necessary.

We note that Section 11(b) also specifies that the requirements of Chapter 8.8 do not relieve an eligible business from the duty to obtain any certificate required under Ind. Code ch. 8-1-8.5 or 8-1-8.7. CAC asserts that I&M should be required to seek a CPCN for its LCM Project. However, Ind. Code ch. 8-1-8.5 applies to the construction, purchase or lease of any facility for the generation of electricity and Ind. Code ch. 8-1-8.7 applies to the construction of a clean coal technology project, which is defined, in part, as a technology that reduces airborne emissions of sulfur or nitrogen based compounds. As the LCM Project involves neither of these activities, a CPCN is not required. Nonetheless, we agree with CAC that in determining the reasonableness and necessity of the LCM Project as required by Ind. Code § 8-1-8.8-11(a), the Commission must consider the same type of factors evaluated when issuing a CPCN.

2. Section 12. Upon determination of a project’s eligibility for incentives, Section 12(a) requires the Commission to provide the eligible business with incentives for a nuclear energy production or generating facility in the form of the timely

recovery of costs incurred in connection with “the study, analysis, development, siting, design, licensing, permitting, construction, repowering, expansion, life cycle management, operation or maintenance of the facilities.” Chapter 8.8 defines a nuclear energy production or generating facility as a facility that: (1) uses a nuclear reactor as its heat source to provide steam to a turbine generator to produce or generate electricity; (2) supplies electricity to Indiana retail customers on July 1, 2011; (3) is dedicated to primarily serving Indiana customers; and (4) is undergoing a comprehensive life cycle management project to enhance the safe and reliable operation of the facility during the period the facility is licensed to operate by the NRC. Ind. Code § 8-1-8.8-8.5(a). It also includes the transmission lines and other associated equipment to serve the facility. Ind. Code § 8-1-8.8-8.5(b).

Section 12(b) and (c) requires the eligible business to apply for approval of a retail rate adjustment mechanism (often referred to as a “tracker”) by providing certain information in the manner determined by the Commission. If the eligible business provides substantial documentation that the expected costs and expenses and the schedule for incurring those costs and expenses for the clean energy project are reasonable and necessary, then the Commission shall allow recovery of the costs associated with qualified utility system property¹⁰ and qualified utility system expenses.¹¹ Ind. Code § 8-1-8.8-12(d). The rate adjustment mechanism may be based on actual or forecasted data. Ind. Code § 8-1-8.8-12(f). But, if forecast data is used, the rate adjustment mechanism must contain a reconciliation mechanism to correct for any variance between the forecasted costs and the actual costs. *Id.*

Therefore, in order to approve the timely recovery of costs and expenses associated with the LCM Project through a rate adjustment mechanism, the Commission must determine that:

1. I&M is an eligible business which has applied for a rate adjustment mechanism in the manner determined by the Commission;
2. the Cook Plant is a nuclear energy production or generating facility;
3. the expected costs and expenses for the LCM Project and the schedule for incurring those costs and expenses are reasonable and necessary.

B. Eligibility of the LCM Project for Financial Incentives. The parties do not dispute that I&M is an “eligible business” since it is an energy utility proposing to construct two types of clean energy projects: (1) projects that enhance the safe and reliable operation of nuclear energy production or generating technologies to produce electricity, and (2) electric transmission facilities serving a nuclear energy production or generation facility. Nor is it disputed that the Cook Plant is a “nuclear energy production or generation facility.” The evidence demonstrates the Cook Plant uses a nuclear reactor as its heat source to provide steam

¹⁰ These costs include capital, operation, maintenance, depreciation, tax costs and financing costs of, or for, a nuclear energy production or generating facility used to provide retail energy service. Ind. Code § 8-1-8.8-5 and -9.

¹¹ These expenses include the costs associated with the study, analysis, or development of a life cycle management project for a nuclear energy production or generating facility. Ind. Code § 8-1-8.8-8.7.

to a turbine generator to produce electricity and has been supplying electricity to Indiana retail customers since the 1970s up to the present time. While the Cook Plant generates power utilized by customers in Michigan and Indiana, among others, nearly 65% of its capacity is allocated to Indiana retail customers. Therefore, it is dedicated primarily to serving Indiana customers. It is also clear from the evidence presented that the Cook Plant is undergoing a comprehensive life cycle management project intended to enhance the safe and reliable operation of the facility during the Units' extended NRC license periods.

Therefore, we are left to determine whether a portion or all of the LCM Project, which consists of 117 individual sub-projects, qualifies as a clean energy project.¹² And if so, whether the LCM Project, its estimated costs and expenses and the schedule for incurring those costs and expenses are reasonable and necessary.

1. Life Cycle Management. Chapter 8.8 uses the term “life cycle management” in various sections of the statute. It uses the term in defining what is a nuclear energy production or generating facility, *i.e.*, one that is undergoing a comprehensive life cycle management project to enhance the safe and reliable operation of the facility. Ind. Code § 8-1-8.8-8.5(a)(4). The term is also used to indicate what financial incentives may be provided to an eligible business, *i.e.*, timely recovery of costs incurred in connection with life cycle management (Ind. Code § 8-1-8.8-12(a)(2)) and recovery of costs associated with the study, analysis or development of a life cycle management project (Ind. Code. §§ 8-1-8.8-12(d)(2) and 8-1-8.8-8.7. However, Chapter 8.8 does not define the term “life cycle management,” nor does it identify “life cycle management” as a “clean energy project.” Yet, when the statute is read as a whole, and keeping in mind the expression of legislative intent at the time of the 2011 amendments, it is clear that life cycle management is a comprehensive project undertaken at a nuclear energy production or generation facility, such as the Cook Plant, that is intended to enhance the safe and reliable use of nuclear energy.

Mr. Carlson testified that the standard industry definition of life cycle management is:

The integration of aging management and economic planning to optimize the operation, maintenance, and service life of Systems, Structures, and Components (SSCs); maintain an acceptable level of performance and safety; and maximize return of investment over the service life of the plant.

I&M further limited this definition for purposes of the LCM Project to those projects that are non-recurring capital replacements necessary to operate the Cook Plant for the extended NRC license period. I&M's methodology for determining whether to include a particular sub-project in its development of the LCM Project is set forth in further detail on Petitioner's Exhibit MHC-8. Dr. Roe explained the purpose of a life cycle management process is the timely detection and mitigation of aging effects in SSCs that are important to plant safety, reliability and economics. He indicated it was also a process used to meet regulatory requirements for license renewal and maintenance.

¹² We note that at the time of the hearing, the LCM Project was comprised of 114 sub-projects due to one project being eliminated and two other projects being combined with other projects. Tr. at F-71 thru F-72.

None of the parties disagreed with the standard industry definition of life cycle management. The OUCC's witness, Mr. Sobel, expressed agreement with the industry definition and further testified that,

[t]he LCM Project is the result of the systematic analysis that provides a sufficient level of confidence that a plant designed for 40 years can continue to operate safely and at an acceptable level of performance for another 20 years. The LCM Project considers, among other things, aging effects, operations, maintenance, performance level and safety to determine those actions and activities necessary to achieve that sufficient level of confidence.

These actions and activities should be taken since the analysis performed determined that they are necessary to achieve the level of confidence to operate the Units for another 20 years.

OUCC Ex. 2 at 11-12.

2. LCM Project as a Clean Energy Project. The parties asserted various arguments as to why the LCM Project, or certain sub-projects, should not qualify as clean energy projects eligible for financial incentives. The OUCC primarily argues that only those sub-projects that are directly safety related or mandated by the NRC license renewal should qualify as clean energy projects. The I&M IG, on the other hand, argues that there is nothing unique about the 117 sub-projects that makes the tracking of their costs justified and urges the Commission to consider establishing a minimum cost threshold when approving the sub-projects eligible for financial incentives.

Before addressing the parties' arguments, we must first determine whether the LCM Project should be considered a single project or whether each individual sub-project constitutes a separate and distinct project for purposes of satisfying the statutory definition of clean energy project. I&M argues that the LCM Project is a single project and should be reviewed as such to determine its eligibility for financial incentives, whereas the OUCC and the I&M IG argue each sub-project should be independently evaluated to determine its eligibility.

As noted above, there is general agreement as to how life cycle management is defined within the industry. Based on that definition, it appears that life cycle management is a process designed to identify or develop a group of projects or sub-projects to serve a specific objective. As such, a life cycle management project will consist of multiple projects or sub-projects intended to address the reasonable and continued operation of an entire nuclear facility. This conclusion is consistent with Mr. Chodak's testimony concerning the extensive analysis I&M undertook to identify the sub-projects that needed to be performed to ensure continued operation of the Cook Units for another twenty years as a result of the NRC license extension. It is also consistent with the fact that the Legislature appears to have defined a clean energy project as projects other than simply life cycle management. Clearly, the Legislature could have declared "life cycle management" to be a clean energy project. Instead, Ind. Code § 8-1-8.8-2(1)(E) defines a clean energy project to include those projects that enhance the safe and reliable use of nuclear energy to produce electricity, one of which is arguably life cycle management.

While we agree with I&M that the LCM Project should essentially be evaluated as a single project for purposes of determining whether it is eligible for financial incentives as a clean energy project, we cannot ignore the fact that it is comprised of multiple discrete sub-projects. Therefore, we find it necessary to also consider the parties' arguments and whether the sub-projects generally fall within the standard industry definition of life cycle management, which has the intended purpose of enhancing the safe and reliable operation of the Cook Units during its NRC license extension.

As discussed in further detail below, we find that I&M has demonstrated that the LCM Project, as a whole and with the exception of the upsized components, qualifies as a clean energy project. The LCM Project will address both safety and reliability issues at the Cook Plant, allowing the Plant to safely and reliably operate for an additional twenty years.

a. Primarily Safety or NRC Required. The OUCC argues that a number of the LCM sub-projects are not sufficiently safety related to qualify as a clean energy project under the statute, which requires a project to enhance both safety and reliability. Mr. Sobel explained that for each sub-project, I&M identified the primary requirement that it believes justifies each of the sub-projects as either safety or reliability. Fifty-six (56) LCM sub-projects totaling about \$400 million were identified as being required for safety, and the remaining sixty-one (61) LCM sub-projects totaling about \$549 million were identified as being required for reliability.

Mr. Sobel testified that I&M's definition of "safety" is too broad and goes well beyond the definition of safety in the NRC rule applicable to reactor license renewals. He stated that because I&M's definition of safety includes non-safety SSCs, the LCM Project includes sub-projects that are not primarily safety driven. The OUCC also asserts that none of the sub-projects are specifically mandated by the NRC's license renewal, but indicates there may be approximately 18 sub-projects that indirectly fulfill an NRC commitment.

Dr. Roe, however, disagreed with Mr. Sobel's definition of "safety" for purposes of life cycle management. Dr. Roe explained the NRC has two major rules related to life cycle management with which I&M must comply: license renewal and the Maintenance Rule. The Maintenance Rule is a performance based rule that includes both safety and non-safety related SSCs. Dr. Roe stated that I&M's definition correctly describes the understanding of the NRC and industry concerning nuclear safety with regard to the operation of nuclear power plants. Dr. Roe explained that Mr. Sobel's definition is inconsistent with the Maintenance Rule and does not reflect the regulatory requirements for maintenance of a nuclear power plant. He testified I&M must comply with both the license renewal rule and the Maintenance Rule.

On cross-examination at the hearing, I&M witness Mr. Carlson, acknowledged the NRC has not explicitly required that I&M perform any of the proposed sub-projects, but emphasized that I&M is required to maintain the plant safely and reliably, which it would not be able to do without performing the proposed sub-projects. Tr. at B-118. Mr. Carlson also explained that, although the NRC may use the phrase "non-safety related" to describe certain equipment, it does

not mean that there are not substantial safety implications associated with such equipment. *Id.* at B-121 thru B-124.

Based on the evidence presented, we find that I&M's broader definition of "safety" is consistent with NRC regulation and the industry definition of life cycle management, which includes both safety and non-safety related SSCs. The safety and reliability of the U.S. nuclear power plants, including Cook, are subject to oversight and regulation by the NRC. The NRC's requirements, as found in the licensing basis requirements, the license renewal commitments, and the Maintenance Rule, are both prescriptive in some cases, and performance-based in other cases. These NRC rules and requirements focus on both safety and reliability. The evidence demonstrates that the NRC recognizes that reliability is often an integral part of safety, in that even what the NRC considers to be technically "non-safety related," has both safety and reliability implications.

The evidence demonstrates the sole purpose of I&M's LCM Project is to address equipment aging issues, so as to allow the Cook Plant to continue to operate both safely and reliably during the extended twenty-year license renewal periods. The evidence also shows that the sub-projects to which the OUCC objects have clearly identified issues which, in the absence of the proposed life cycle management activities, would affect their ability to meet the extended operating life. Even the OUCC's witness Mr. Sobel agrees that the sub-projects should be performed to extend the life of the facility. Therefore, we find I&M's LCM Project to be consistent with the accepted industry definition of life cycle management, which as a whole is intended to enhance the safe and reliable use of nuclear energy to produce electricity so as to meet the definition of a clean energy project.

Nor is our conclusion altered by the OUCC's contention that most, if not all, of the LCM sub-projects are not mandated by the NRC and thus should not qualify as clean energy projects. Nothing in Chapter 8.8 requires that clean energy projects be mandated by a governmental agency in order to qualify for financial incentives. The legislative intent is clear that we are to encourage safety and reliability investments in nuclear power plants, such as Cook, that are undergoing a comprehensive life cycle management project. We decline to create such an extra-statutory limitation.

b. Unique or First of a Kind. Both the OUCC and I&M IG argue that many of the LCM sub-projects are not sufficiently unique to qualify for financial incentives. The OUCC notes that several of the sub-projects are typical O&M activities that all electric utilities undertake from time to time, such as the replacement of the Unit 2 turbine, the transformers and generator exciters. The OUCC argues that other electric utilities are not afforded expedited cost recovery for these types of projects and nor should I&M.

I&M IG argues that the sub-projects are not "first of a kind" projects that justify establishment of a tracker. Therefore, I&M IG recommended the Commission limit recovery through a tracker to those individual projects whose cost is material and substantial, to the extent otherwise recoverable under Chapter 8.8. More specifically, it was recommended that we impose a minimum dollar threshold (\$50 million, or at a minimum, \$20 million) for each LCM sub-project in order to allow cost tracking for that sub-project.

Nothing in the statute requires that projects be “unique” or “first of a kind.” Ind. Code § 8-1-8.8-2(1)(E) merely requires the projects “enhance the safe and reliable use of nuclear energy production or generating technologies to produce electricity.” The evidence in this case indicates that requiring projects to be “unique” would be illogical; as many U.S. nuclear power plants are undergoing life cycle management investments in connection with license extensions, it is to be expected that these projects will not be unique or one of a kind. That said, the evidence also shows that I&M’s LCM Project is unique in certain respects: it is a comprehensive life cycle management project that considered the entire operations of the Plant undertaken solely for the purpose of allowing the Units to continue to operate safely and reliably during their twenty-year extended license periods. Moreover, the evidence demonstrates the LCM Project is separate and apart, over and above, a normal ongoing level of capital maintenance at the Cook Plant. Additionally, the LCM Project is an infrequent program, with interrelated sub-projects having staggered construction schedules over more than 6 years.

Further, we do not find the OUCC’s and I&M IG’s reliance on the Vectren Dense Pack case to be relevant in this instance. That case involved an entirely different subsection of the statute, and an entirely different statutory analysis. In that case, we determined that the proposed dense pack project at a coal-fired generating unit did not qualify as “advanced technology” for purposes of satisfying the definition of a clean energy project under Ind. Code § 8-1-8.8-2(1)(B); accordingly, we rejected the utility’s request for timely cost recovery of that particular investment. The Vectren Dense Pack case offers no guidance or precedent with respect to the eligibility of nuclear power plant life cycle management investments under the statute for purposes of satisfying the definition of a clean energy project under Ind. Code § 8-1-8.8-2(1)(E). The OUCC’s and I&M IG’s argument, at its essence, seems to be that they are not in favor of the financial incentives created by the Legislature for these projects; they would prefer for the investments to be recovered in traditional rate cases. This is an argument for the Legislature, not the Commission. For all of these reasons, we decline to impose any requirement that the project be “unique” or meet a minimum dollar threshold.

c. Upsized Components. I&M seeks to include \$23 million in incremental costs for upsizing certain sub-projects (specifically, a transformer, heat exchangers, and pumps) in its LCM Project in order to accommodate a future potential power uprate. I&M claims that upsizing these components now will save ratepayers money later in the event an extended power uprate is pursued and obtained. I&M also argues that such costs may be appropriately included in life cycle management as a project to “maximize return of investment over the service life of the plant.” The OUCC and I&M IG oppose this inclusion because the uprate capacity does not enhance safety or reliability, may never be needed, could be rejected by the NRC if proposed, and the cost (and therefore the reasonableness) of a potential uprate is unknown.

Mr. Chodak testified that I&M has not requested, nor is it requesting, a power uprate at this time. The OUCC also pointed out that I&M’s IRP does not demonstrate a need for additional capacity until Tanners Creek Unit 4 is retired, which is not expected until 2024 – more than half-way into the Cook Plant’s extended licensing period. The IRP further indicates that the optimal replacement technology for the Tanners Creek Unit 4 is a natural gas combined cycle

facility, not a power uprate to the Cook Plant. I&M provided no evidence as to when, or if, a power uprate would be pursued. Instead, the Company emphasized that the timing of the need for additional capacity is uncertain, due to continuing uncertainty surrounding environmental regulations and the resulting uncertainty of coal-fired unit retirement dates, as well as uncertainties surrounding the economy and load growth.

Although I&M provided at the hearing some rough estimates of possible benefits that may result from upsizing the facilities now as opposed to waiting until the time of an uprate, it provided no evidence concerning the likelihood that an uprate would be pursued. Nor has I&M performed any studies, analysis or investigations to estimate or determine the cost of an uprate. The parties also disagreed on the feasibility of obtaining NRC approval should I&M determine to pursue a power uprate.

Based on the evidence presented, we find that the incremental costs for the upsized components are not properly considered life cycle management and fail to satisfy the definition of a clean energy project. The evidence demonstrates that the upsizing of these components is not necessary from a safety and reliability perspective or to allow the Cook Units to operate during its extended license period. *See*, Tr. at B-60 thru B-61. Rather I&M seeks recovery of the upsizing costs as a “hedge,” a cost incurred today that presents cost advantages for a future power uprate, should one ever be determined necessary.

While we are not approving the inclusion of the \$23 million in incremental costs associated with upsizing certain components, we are not making any determination concerning the reasonableness of incurring those costs should I&M determine it appropriate to upsize those components. Making such an investment now may very well be reasonable as a prudent hedge, particularly given the direction of the U.S. government concerning environmental regulation,¹³ but that does not make it a clean energy project eligible for the financial incentives under Chapter 8.8. Moreover, this determination does not foreclose I&M the opportunity to seek recovery of the incremental costs of the upsized components through more traditional means, such as a base rate case.

3. Reasonableness and Necessity for the LCM Project, Including the Expected Costs and Schedule. Having determined that the LCM Project, as a whole with the exception of the upsized components, qualifies as a clean energy project, Section 11 next requires that we determine whether the LCM Project is reasonable and necessary so as to be eligible for the timely recovery of costs and expenses and other financial incentives. If so, and in order to timely recover qualified utility system expenses and costs associated with qualified utility system property, Section 12 requires I&M demonstrate the Project’s expected costs and the schedule for incurring those costs are reasonable and necessary.

a. LCM Project. Notably, Section 11 provides no guidance on the factors that the Commission should consider in reviewing whether the LCM Project is reasonable and necessary. In prior determinations under Chapter 8.8, the Commission has generally relied upon the factors necessary for obtaining a certificate under Ind. Code ch. 8-1-8.5

¹³ *See e.g.*, The President’s Climate Action Plan, June 2013, <http://www.whitehouse.gov/share/climate-action-plan>.

("Chapter 8.5") or 8-1-8.7 ("Chapter 8.7"). While we acknowledge the LCM Project is unlike other capital projects the Commission has previously approved under Chapter 8.8 because it does not require a certificate under either Chapter 8.5 or 8.7, we nonetheless find that an analysis of similar types of factors considered for a certificate to be appropriate in this instance. Particularly, we find relevant the type of factors under Chapter 8.7 where, similar to the purpose of life cycle management, a primary purpose of many clean coal technology projects has been to extend the useful life of an existing electric generating facility. *See e.g., Duke Energy Indiana, Inc.*, Cause No. 44217 (IURC April 3, 2013); *Northern Indiana Public Service Company*, Cause No. 44012 (IURC December 28, 2011). Therefore, in determining the reasonableness and necessity for the LCM Project, we find it appropriate to consider the following factors: the necessity of the LCM Project for continued safe and reliable operation of the Cook Plant during the extended license period; the reasonableness of the cost for the LCM Project compared to the cost of alternative plans; whether the LCM Project will extend the useful life of the Cook Plant and the value of that extension; the likelihood of success of the LCM Project; and the expected costs of the LCM Project.

Several I&M witnesses testified that the LCM Project is necessary in order to continue to operate the Cook Units safely and reliably for the additional twenty-year license renewal periods. More specifically, Mr. Carlson testified that the Cook plant was originally designed and built based on an expected life of forty years. Consequently, the twenty-year license renewals require actions be taken to address the effects of component aging and compliance with NRC regulations and requirements. Dr. Roe testified that he agreed with Mr. Schoepf that the LCM Project is being performed for the sole purpose of fulfilling the extended unit operating licenses, that the LCM Project would not be done if the operating lives had not been extended, and that all of the sub-projects are necessary for the Cook Units to continue safe and reliable operation during the extended license periods.

No party to this case specifically disputed that I&M should undertake the proposed sub-projects, or that these sub-projects are necessary to ensure continued operation of the Cook Units for their extended license renewal periods. Mr. Keen testified that the OUCC generally supports I&M's plans to upgrade, maintain and operate the Cook Plant in a safe and reliable manner in order to continue providing energy to Indiana ratepayers. OUCC Ex. 1 at 4. Similarly, Mr. Sobel emphasized that while the OUCC was recommending that only a portion of the LCM Project costs be recovered through the LCMR, the OUCC was not recommending that only certain LCM sub-projects be implemented. OUCC Ex. 2 at 9. And I&M IG's witness, Mr. Phillips, also acknowledged that I&M's testimony makes it clear that these projects are necessary to allow for the Cook Plant to reliably operate beyond the original lifespan. I&M IG Ex. 1 at 5. So, while the parties disputed whether certain sub-projects were entitled to timely cost recovery under Chapter 8.8, there appears to be general agreement concerning the necessity for the LCM Project to allow for continued operation of the Cook Units under the extended license renewals.

Based on the evidence presented, it is also evident that the LCM Project is reasonable when compared to other alternatives, *i.e.*, retirement of the Units and replacement with other resources. Mr. Chodak testified that the Cook Units are among the lowest cost generation facilities on the AEP system. He emphasized that the Cook Plant's emission-free generation of

electricity was integral to I&M's long term resource strategy. Mr. Torpey provided testimony demonstrating that making the LCM Project investment and retaining the availability of the Cook Units is the preferred option at capacity factors for the Cook Units of greater than 20%, and the projected Cook Units' capacity factors are significantly higher than 20% (from above 70% to above 90%). The Company's analyses also demonstrated that the PVRR benefits to customers of a resource portfolio including the LCM Project and continued operation of the Cook Units, versus a portfolio where the Cook Units are retired in the near future, are in the range of \$3.1 billion to \$4.5 billion.

While CAC's witness, Mr. Athas, made some suggestions and observations that have merit with respect to IRPs in general, they do not change the fact that the LCM Project is the overwhelmingly preferred resource option. Even when the Company adopted Mr. Athas' low natural gas price forecast, the results did not materially change. In sum, the option of making the LCM Project investments and continuing operation of the Cook Units has a significant cost advantage over other alternatives, and we so find.

b. Expected Costs and Expenses and Proposed Schedule. The OUCC and I&M IG make several arguments that go to the reasonableness of the LCM Project and associated costs. First, they argue that the cost estimates are of questionable accuracy, especially for sub-projects in early phases, and that therefore, the Commission should approve such cost estimates only at the lower end of the ranges. Similarly related, they also argue that some sub-projects are not fully defined, and thus such sub-projects should not be approved at this time. Second, they argue that the management reserve is unreasonable and should be excluded from the Project cost estimate.

i. Cost Estimates. With regard to the accuracy of the cost estimates, especially for those sub-projects in the early phases, the OUCC testified that it is concerned about the level of engineering and cost analysis completed to date. The OUCC expressed concern with the large number of sub-projects that are in phases with a cost estimate accuracy factor of +/- 50%, 25%, and 15% (*i.e.*, Phases 1, 2A and 2B) and argues that the estimates lack the detail necessary to justify cost recovery. Accordingly, the OUCC recommends that the Commission approve funding at the lower end of I&M's cost estimate range for the sub-projects that are deemed to be eligible under the LCM tracker. In addition, at the hearing, the I&M IG also took issue with I&M's initial failure to adequately: explain the \$12.4 million in study, analysis and development costs; indicate that I&M's direct costs had been included in the Shaw estimate; and address the inclusion of indirect costs. Both the OUCC and I&M IG also noted that since the filing of I&M's Petition several sub-projects had greatly exceeded their cost estimate, other sub-projects had regressed in phase, and still others had been combined or eliminated.

In contrast, multiple I&M witnesses testified that the individual I&M cost estimates for each LCM sub-project were developed in accordance with industry standard cost estimating guidelines based upon the information known at the time. They explained I&M used several accepted methods of estimating the sub-project costs, including reliance on a study developed by an outside EPC contractor, bottoms-up cost estimates, benchmarking by internal and external groups, and internal management reviews and approvals. Mr. Denver testified that the use of

project management phases, with different cost estimate accuracies at different phases, is reasonable and consistent with industry standards. Both Mr. Schoepf and Mr. Denver testified that the level of accuracy of overall project costs is always evolving based on the bottoms-up nature of the sub-project cost estimates and the multi-year nature of the LCM Project. However, the estimate accuracy will improve with project definition and engineering or design progress. Mr. Denver also stressed that each of the sub-projects implement routine power plant modifications, such that even in early project phases there is a high confidence level in the estimates. He also testified that I&M's project management procedures and practices are designed to ensure consistent application of cost-estimating principles across the sub-projects and allow management to impose consistent expectations across the organization. I&M consistently expressed that because of the diversity of the sub-projects, none of which are first-of-kind, the total LCM Project cost estimate will be more accurate than looking at each sub-project on an individual basis.

I&M explained the study, analysis and development costs were associated with the Shaw estimates and allocated among those sub-projects. I&M also ultimately confirmed that the LCM Project cost estimate includes both direct and indirect costs. Mr. Schoepf, acknowledging he was not an accountant, explained at the hearing that direct costs includes things like material, labor and other costs within the control of the Project Manager, whereas the indirect costs were things not within the Project Manager's control. Tr. at D-64. He also confirmed that 10% of the LCM Project estimate, including management reserve, is for indirect costs, which was based upon I&M's experience with other major capital projects. Tr. at D-65 thru D-67, D-82. In response to the parties' concerns with the changes to sub-projects from the time of Petitioner's pre-filing of Exhibit TJB-5, Mr. Schoepf explained that changes were occurring daily – changes to cost estimates, timing of project implementation, and phases – but that he fully expects I&M to provide explanations for these changes in the ongoing review process that I&M has requested. Tr. at E-42 thru E-43. He also noted that the LCM Project estimate at the time of the hearing was within one percent of I&M's initial \$1.169 billion estimate.

We note that the LCM Project is different from many other clean energy projects in that it is a large and comprehensive project consisting of 117 discrete construction sub-projects over multiple years, as opposed to the construction of a single piece of equipment, such as a pollution control device. Given the nature of the LCM Project, we find I&M's phased estimate approach to be reasonable. While we have consistently encouraged utilities to improve the accuracy and completeness of their cost estimates prior to seeking Commission pre-approval for a project, we have also recognized that the circumstances of a project may dictate the range of accuracy. *See Northern Indiana Public Service Company*, Cause No. 44012 at 18, (IURC Dec. 28, 2011). The evidence shows that a comprehensive project of this magnitude over multiple years requires substantial project planning and management and necessarily requires more variances in sub-project estimated costs in the early stages. I&M demonstrated that its cost estimating process for the LCM Project was conducted in accordance with industry standards and that it has an appropriate project management process in place. The ongoing review process requested by I&M, discussed in more detail below, will also assist in optimizing our regulatory review of the LCM Project as it evolves.

Along with the amount of management reserve included in the LCM Project, as further discussed below, the biggest area of confusion and disagreement among the parties involved the components I&M had included, or had not included, in its cost estimates, as well as subsequent changes in those estimates. It is clear from the evidence presented that I&M failed to communicate clearly and effectively concerning the cost estimates contained in its Exhibit TJB-5 until the very end of this proceeding. Unfortunately, this caused confusion and skepticism by the parties and worked to instill a lack of trust in I&M. I&M has requested approval of an ongoing review process and Mr. Krawec testified that I&M is committed to working with the OUCC and other intervenors to develop schedules and an audit package which “allows for a thorough review to support the cost recovery of each sub-project...” Pet. Ex. M at 3. Therefore, we fully expect I&M to remedy the situation created in this Cause going forward, and to improve its communication with the parties and the Commission in the ongoing review authorized further below in this Order.

ii. Management Reserve. With regard to contingency (*i.e.*, management reserve), I&M seeks approval to include \$220 million, or approximately 20% of the LCM Project cost plus 10% for indirect costs, in its cost estimate. The OUCC and I&M IG argue that management reserve costs should be excluded from any approved project cost estimate. The rationale for excluding this contingency is the uncertainty as to whether or not it would be needed, and, in the OUCC’s opinion, that there may be extra layers of contingency already included in the sub-project cost estimates, for example, in the form of indirect costs. The OUCC also relied on an AACE definition of management reserve, which it interpreted as supporting its position that management reserve should be excluded from the LCM Project cost estimate. The OUCC argued that management reserve means that a change in the project scope must occur, and if a change in project scope occurs, I&M should seek Commission approval of such project scope changes in a separately docketed proceeding.

While I&M’s initial filing indicated that two types of contingency, *i.e.*, risk reserve and management reserve, were included in the cost estimates to account for uncertainties, I&M subsequently indicated in its rebuttal and supplemental rebuttal testimony filings that the only contingency included in the LCM Project cost estimate is the \$220 million of management reserve costs.¹⁴ At the evidentiary hearing, Mr. Chodak again emphasized that the management reserve was the only contingency in the filed estimate. Tr. at A-43 thru A-45. Given that the management reserve is the only contingency in the LCM Project estimate, the evidence indicates that the \$220 million estimate comports with industry standards and practices. I&M demonstrated that the amount of contingency in the management reserve, approximately 20%, was reasonable and relatively conservative given the diversity of sub-projects. I&M witnesses explained that while there may be some savings that can be achieved on some sub-projects, that is not a certainty, and the sub-project cost estimates do not assume savings. Rather, they represent the Company’s best (or expected) estimate of what the sub-project will cost. Mr.

¹⁴ I&M’s response to an I&M IG discovery request stated, “The forecast amount for each sub-project shown in Confidential Exhibit TJB-5 represents the total projected cost of each sub-project **including risk reserve.**” Exhibit NP-3 attached to I&M IG’s Ex. 1 (emphasis added). Subsequent to the filing of this discovery response, I&M filed the rebuttal testimony of Mr. Schoepf stating, “The cost estimates presented in Exhibit TJB-5 are the expected costs for the sub-projects **without contingency....**” I&M Ex. I at 5 (emphasis added). Like the parties, we find it somewhat disingenuous that I&M characterizes this change as an attempt to “clarify the parties’ misunderstanding.”

Denver further testified that, based on the value and planning phase of the sub-projects, a contingency of about 33% could be justified for the LCM Project. Mr. Schoepf also explained that the AACE definition of “management reserve” does provide for inclusion of management reserve in the total project cost estimate, just not until after the individual project work is accounted for, which I&M has done.

We agree that contingency is a necessary element of a complete project cost estimate and routinely included in major construction projects approved by the Commission. *See, e.g., Northern Indiana Public Service Company*, Cause No. 43913 at 9-12 (IURC Dec. 29, 2010); *Duke Energy Indiana, Inc.*, Cause No. 44217 at 12, 29 and 35-36 (IURC April 3, 2013). The evidence demonstrates that an amount of \$220 million for management reserve is reasonable given the magnitude and complexity of the project. We also reject the argument that we should consider either indirect costs or potential sub-project cost savings as additional layers of contingency. Indirect costs are real costs related, but not directly applied, to a construction project. We also find that the OUCC’s concern about changes in sub-project scope and corresponding uses of management reserve, can be addressed adequately through the ongoing review proceedings.

iii. Proposed Schedule. I&M proposed to perform the LCM Project over the course of six years. Mr. Carlson testified that the major construction activities will be largely performed in conjunction with major refueling outages, which will limit unit downtime and optimize plant reliability. He also noted that some sub-projects can be performed while the units are on-line, which will provide I&M with greater flexibility in scheduling labor and materials. No party took issue with the proposed schedule for performing the sub-projects. Based on the evidence provided, we find that the proposed schedule is reasonable and necessary, as it allows each of the sub-projects to be performed safely and in a reasonable timeframe designed to limit unit unavailability.

c. Conclusion. Based on the evidence presented, we find Petitioner’s LCM Project, the cost estimate contained in I&M’s Confidential Exhibit TJB-5 with the exception of the approximately \$23 million in incremental upsizing costs, and the proposed implementation schedule to be reasonable and necessary and is approved for purposes of receiving financial incentives authorized under Chapter 8.8. As discussed above, the evidence demonstrates that the expected cost of \$1.169 billion, less the approximately \$23 million in incremental upsizing costs, for the LCM Project is reasonable and necessary for the safe and reliable operation of the Cook Units during the extended licensing period. Throughout this proceeding I&M expressed a high degree of confidence in its cost estimate for the LCM Project and its ability to successfully manage the project’s implementation within that cost estimate. Therefore, our approval of the expected costs as reasonable and necessary is limited to the expected cost of \$1.169 billion, less the approximately \$23 million in incremental upsizing costs. Any increase in expected cost of the LCM Project for which I&M intends to seek cost recovery will require additional approval in a separate proceeding that allows for public notice and an evidentiary hearing.

4. Financial Incentives. I&M seeks the following financial incentives in the form of timely recovery of: (1) its financing costs incurred during construction of the LCM

Project, for all such sub-projects that are under construction on and after January 1, 2012; (2) its post-in-service financing costs, and incremental depreciation and property tax costs and expenses, associated with the LCM Project and incurred on and after January 1, 2012; and (3) its costs associated with the study, analysis, or development of the LCM Project, through a periodic rate adjustment mechanism to commence upon approval by the Commission in this proceeding and to be updated every six months thereafter. Additionally, Petitioner requests the Commission authorize it to defer, on an interim basis, certain O&M costs (specifically, incremental depreciation and property tax costs), along with study, analysis and development costs, until the applicable costs are included in Petitioner's retail electric rates. Petitioner also requests that the Commission authorize it to add all earnings on its LCM Project to its authorized net operating income ("NOI") for purposes of the FAC earnings test under Ind. Code § 8-1-2-42(d)(3).

This requested relief consists of essentially three categories: (1) timely recovery of LCM Project costs; (2) interim deferred accounting treatment; and (3) adjustment of I&M's authorized NOI to reflect LCM Project earnings.

With regard to I&M's request for timely recovery of LCM Project costs (which includes pre- and post-in-service financing costs, incremental depreciation and property tax expenses, and LCM study and analysis costs), it is clear that this relief is authorized by Sections 11 and 12. Section 11 allows timely recovery of costs and expenses incurred during construction and operation of a clean energy project; while Section 12 more broadly authorizes timely recovery of costs incurred in connection with the study, analysis, development, siting, design, licensing, permitting, construction, repowering, expansion, life cycle management, operation, or maintenance of nuclear facilities such as the Cook Plant that is undergoing a comprehensive LCM. Accordingly, we find that I&M should be authorized to recover on a timely basis its LCM Project costs, with the exception of the incremental costs associated with the upsized components and limited to the amount of expected costs determined to be reasonable and necessary herein (*i.e.*, \$1.169 billion less the amount of the incremental upsizing).

With regard to the OUCC's concern that there could be additional recovery on replaced equipment in base rates at the same time new equipment will be tracked through the LCM, we are not persuaded that this concern is justified. As Mr. Krawec explained, I&M's proposal mitigates this potential by virtue of the Company requesting recovery of incremental depreciation expense, incremental property tax increase, and carrying charges for post-in-service equipment. Further, we agree with Mr. Krawec that when the replaced item is retired, the remaining original cost is transferred to the accumulated depreciation reserve account. This causes depreciation expense to decrease, but there is no effect on net plant balances, and accordingly, no effect on rate base. And because rate base is unchanged by the retirement, it would not be appropriate to reduce the incremental carrying charge on the new asset as suggested by Mr. Blakely.

With regard to the request for interim deferred accounting treatment related to the LCM Project costs, the OUCC and I&M IG urge us to reject this request due to the Company's failure to provide evidence of the harm or earnings erosion that would occur in the absence of the requested relief. This argument fails for several reasons. First, Chapter 8.8 authorizes timely recovery for these LCM Project costs. Interim deferred accounting treatment goes hand in hand

with timely recovery of costs. Without interim deferred accounting treatment, the Company will not be able to fully recover its LCM Project costs. Given the statutory directive that the Commission should encourage investments of this type by allowing for timely recovery of the costs, we believe denial of interim accounting treatment would be inconsistent with the intent of the statute. Related to this, we note that we have not, in fact, required utilities to make showings of harm or earnings erosion in cases where there was explicit authorization for timely cost recovery, as is the case here. *See, e.g., Duke Energy Indiana, Inc.*, Cause No. 44217 (IURC April 3, 2013); *Northern Indiana Public Service Company*, Cause No. 44012 (IURC Dec. 28, 2011); *Indiana Michigan Power Company*, Cause No. 43750 (IURC Jan. 6, 2010). Rather, we have required those showings in cases where there is no specific statutory authorization for timely recovery of costs. Accordingly, we find that I&M should be authorized to defer for subsequent recovery, on an interim basis, LCM Project-related costs, as requested in its petition and testimony.

Further, we approve I&M's request to adjust its authorized NOI to reflect LCM Rider earnings. Section 12 authorizes the recovery of financing costs associated with qualified utility system property. We note that we have routinely granted such treatment in other capital rider cases. *See, e.g., Indiana Michigan Power Company*, Cause No. 43636 ECR 5 (IURC March 28, 2012); *Indianapolis Power & Light Company*, 42170 ECR 20 (IURC Feb. 27, 2013). Such an adjustment synchs up a utility's authorized return with its authorized ratemaking treatment for its capital expenditures and is reasonable ratemaking.

Finally, the financial incentives approved herein are applicable only to the Indiana retail jurisdictional portion of the approved LCM Project cost, which is approximately \$741 million.

C. LCM Rider and Initial Rates. As noted above, Section 12 authorizes the timely recovery of costs through a rate adjustment mechanism. The eligible business is required to apply for approval of the rate adjustment mechanism in the manner determined by the Commission. Section 12(f) also provides that a proposed retail rate adjustment mechanism may be based on either actual or forecasted data. However, if forecast data is used, the retail rate adjustment mechanism must contain a reconciliation mechanism to correct for any variance between the forecasted costs and the actual costs.

Mr. Krawec explained that the proposed LCMR is very similar in form and structure to I&M's current environmental trackers. Initially, I&M proposes to provide in the LCMR filing the following information for each sub-project: the construction commencement date, estimated costs at completion, current stage of completion, projected/actual in-service date, and actual construction expenditures and incremental depreciation expense for the recovery period. Mr. Krawec further testified that I&M would work collaboratively with the OUCC and other parties to develop schedules and an audit package that will allow for an efficient review in the LCMR proceedings. The proposed LCM Rider is based on forecasted data and contains a reconciliation mechanism to correct for any variance between forecasted and actual LCM Project costs. I&M also filed its proposed initial LCM Rider rates, based on projections through June 2013, and requested approval of such initial LCM Rider rates in this instant proceeding.

I&M's request for initial LCM Rider rates contemplated the issuance of a Commission order in this Cause by the first billing cycle of January 1, 2013. As noted by the parties and demonstrated by the estimated costs contained in Petitioner's Exhibit 1, I&M's estimated and forecasted costs as initially filed on April 16, 2012 have changed due to the passage of significant time from the initial filing to the issuance of this Order. We also note that the Commission issued an Order on February 13, 2013 in Cause No. 44075 approving new base rates and issued a directive in Cause No. 44256 that is applicable to this proceeding. While no party specifically objected to Petitioner's proposed initial LCM Rider rates, it is unclear whether the OUCC performed an audit or other review of the schedule of costs or expenses underlying the proposed rates or even understood that I&M was seeking approval of initial LCM Rider rates in this Cause. Tr. at G-105 thru G-106. We also note that although the Commission sought additional information from I&M concerning the revenue credits assigned to SDI, I&M did not provide the information necessary for the Commission to confirm the LCM Project costs assigned to the SDI contract will not also be recovered in the LCM Rider.

Accordingly, based on the evidence presented, we find that the form of the proposed LCM Rider complies with the requirements of Section 12. However, for the reasons discussed above, we decline to approve I&M's initial LCM Rider rates at this time. Based upon the complexity of the issues underlying the LCM Project approval itself and the first time application of the statute to such a project, we are concerned that a sufficient level of scrutiny has not been afforded the specific costs that the rates are actually proposed to be adjusted for. Due to this concern, the anticipated delay in the application of the rate adjustment in order to ensure sufficient scrutiny is appropriate and reasonable.¹⁵ Therefore, we find that I&M should collaborate with the OUCC and other parties to develop the appropriate schedules and an audit package to be utilized in the LCMR proceedings and to file updated LCM Rider rates for Commission approval. The first LCM Rider proceeding shall also include the evidence I&M was directed to provide in Cause No. 44256.

Finally, I&M IG witness, Mr. Phillips, recommended that, if we approve the LCM Rider, we should also require I&M to file general rate cases every three years. However, as related solely to the incremental approval of the LCM Rider, the evidence presented fails to show a reasonable public benefit enhancement to be achieved from imposing a requirement to file periodic rate cases. Therefore, we decline to impose such a requirement at this time.

D. Ongoing Regulatory Review of the LCM Project. I&M has requested that the Commission institute an ongoing review process for the LCM Project, similar to such processes under Chapters 8.5 and 8.7. I&M has also stated its willingness to engage an independent third party to monitor the construction and project management, and report to the Commission and the parties about such. The OUCC agrees that the Commission should require I&M to file six month LCM Rider updates, including cost estimations and actual cost expenditures for each sub-project until one reporting cycle after each sub-project has completed Phase 4 of the phased management process.

¹⁵ We also note that requiring I&M to provide updated cost information may help address concerns noted earlier that the OUCC and the I&M IG had with regard to the estimated costs by providing a more current snapshot of the LCM Project costs.

Although the OUCC raised concern regarding the transparency of the LCM Project and the difficulty of tracking the Project's progress, the evidence indicates that the OUCC and I&M have successfully cooperated and collaborated to achieve meaningful reviews for other approved tracking mechanisms. At the evidentiary hearing, Mr. Blakley noted he has been personally involved with several of I&M's riders and agreed that the utility has worked cooperatively to make sure the OUCC has the information needed for the review of those rider filings. Tr. at G-58 thru G-60.

We believe that any transparency and audit ability issues can be addressed through cooperation, collaboration, and the use of both ongoing review proceedings and an independent third party monitor. Accordingly, we direct I&M to provide the following information with respect to LCM Project, as it consists of the 117 sub-projects identified on Petitioner's Confidential Exhibit TJB-5, to the Commission and the parties at six-month intervals in ongoing review reports in conjunction with the Company's LCM Rider filings. Such reporting should continue until one reporting cycle after each sub-project has completed Phase 4 of I&M's phased management process:

1. Updated sub-project phase designations;
2. Updated sub-project cost estimates;
3. Updated risk reserve registers showing identified and quantified risks for any sub-project;
4. Transfers of any "savings" from one sub-project to another;
5. Use of any "management reserve" dollars for any sub-project;
6. Expenditures to date, by sub-project;
7. Percent complete to date, by sub-project;
8. LCM Project timeline showing major tasks and major milestones;
9. Schedule changes;
10. Copies of major contracts entered into relating to the LCM Project;
11. Discussion of any major scope changes determined to be necessary; and
12. Discussion of major issues, problems, challenges

We anticipate that the ongoing review proceedings will address the current status of the LCM Project, as outlined above, and particularly any material changes in the LCM Project cost estimate (as set forth in Petitioner's Confidential Exhibit TJB-5) or schedule, as well as any challenges or problems being experienced with the LCM Project. Our goal is to remain apprised of changes and events in the LCM Project, so that we can take proactive action if necessary in the event of any major changes or problems.

Additionally, we find merit in I&M's proposal to engage an independent expert monitor to assist the Commission and the parties with this ongoing review process. We note that the Michigan Public Service Commission has ordered a similar approach, and in order to allow for parallel treatment on this topic between Indiana and Michigan, I&M shall file an update on the status of selection of an independent expert monitor and the required contents of the update filings to be filed in Michigan within ten (10) days of the date of this Order. The independent expert monitor shall file update reports in I&M's six-month ongoing review proceedings. I&M shall meet with Commission staff, the OUCC and the other parties within thirty (30) days of the

date of this Order to discuss the contents of the update reports to be filed in the ongoing review proceedings. The independent expert monitor shall also file in I&M's first ongoing review proceeding any updates prepared and filed with the Michigan Public Service Commission. Reasonable costs associated with such an independent monitor may be recovered via the LCM Rider.

12. Petitioner's Request for Confidential Treatment. On April 16, September 13, and October 4, 2012, Petitioner filed Motions for Protection of Confidential and Proprietary Information ("Motion"), supported by affidavits. The affidavits set forth facts demonstrating the information to be submitted ("Confidential Information") constitutes a trade secret and the steps taken by Petitioner to protect the Confidential Information from disclosure. On April 23, September 21, and October 9, 2012, the Presiding Officers issued Docket Entries granting confidential treatment to the Confidential Information on a preliminary basis.

Based on the foregoing, pursuant to Ind. Code §§ 8-1-2-29 and 5-14-3-4(a)(4), we find that the detailed LCM Project cost and cost estimate information, fuel and power price forecasts, the outage schedule information, and the INPO reports and communications, as set forth in confidential testimony and exhibits presented in this proceeding, constitute trade secrets and should continue to be afforded confidential treatment. Accordingly, this information is exempted from public disclosure and will be held as confidential by the Commission.

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

1. Petitioner's proposed LCM Project, with the exception of the upsizing of certain components, is reasonable and necessary, and we find that the LCM Project when completed will be used and useful in the provision of retail electric utility service to Petitioner's Indiana customers.

2. The \$1.169 billion estimated construction cost (with the exception of the approximately \$23 million in incremental upsizing cost) and the anticipated construction schedule for the LCM Project are hereby approved.

3. Petitioner is hereby granted certain financial incentives for the LCM Project pursuant to Indiana Code ch. 8-1-8.8, as requested in its Petition and set forth herein.

4. Petitioner is authorized timely recovery of its pre- and post-in-service construction and financing costs, and its incremental depreciation and property tax costs and expenses, associated with the LCM Project and incurred on and after January 1, 2012 through the LCM Rider as set forth herein.

5. Petitioner is authorized timely recovery of its study, analysis and development costs associated with the LCM Project through the LCM Rider as set forth herein.

6. Petitioner's proposed initial LCM Rider rates are denied.

7. Petitioner shall file LCM Rider proceedings semi-annually and may initiate its first LCM Rider proceeding under the Cause No. 44182 LCM 1 within 60 days following the issuance of this Order. The caption in that proceeding shall accurately reflect the relief requested and subsequent filings shall continue to utilize this Cause No. with the next numeric LCM filing designation. The Commission shall conduct ongoing review of the construction of the LCM Project in conjunction with the Petitioner's semi-annual LCM Rider proceedings, as outlined in this Order.

8. Petitioner shall be authorized to defer for subsequent recovery its LCM Project-related post-in-service financing costs, as well as its incremental depreciation and property tax costs and expenses, after the in-service date of the LCM Project to the extent that costs are not reflected in Petitioner's retail electric rates (*i.e.*, through the LCM Rider or in base rates).

9. Petitioner shall be authorized to defer for subsequent recovery its LCM Project-related study, analysis and development costs, to the extent that such costs are not reflected in Petitioner's retail electric rates.

10. Petitioner shall be authorized to adjust its authorized net operating income to reflect earnings on its LCM Project, for purposes of the FAC earnings test.

11. The confidential information presented in this proceeding is found to be confidential and trade secret, excepted from public access, and will continue to be held as confidential by the Commission.

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

ATTERHOLD, BENNETT, LANDIS, MAYS AND ZIEGNER CONCUR:

APPROVED: JUL 17 2013

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



**Brenda A. Howe,
Secretary to the Commission**