ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY FOR MODIFICATION OF ITS CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR CLEAN COAL TECHNOLOGY UNDER IND. CODE 8-1-8.7 et seq. AND PURSUANT TO THE ONGOING REVIEW PROCESS APPROVED IN CAUSE NOS. 42170, 42700 AND 43403 AND FOR APPROVAL OF AN ADJUSTMENT TO ITS RATES THROUGH ITS ENVIRONMENTAL COMPLIANCE COST RECOVERY ADJUSTMENT FOR THE BILLING MONTHS OF MARCH, APRIL, MAY, JUNE, JULY AND AUGUST, 2010, PURSUANT TO THE COMMISSION'S ORDERS IN CAUSE NOS. 42170, 42700 AND 43403.	**CAUSE NO. 42170 ECR 14** **APPROVED:** FEB 24 2010

BY THE COMMISSION:
David E. Ziegner, Commissioner
Aaron A. Schmoll, Administrative Law Judge

On December 18, 2009, Indianapolis Power & Light Company ("IPL" or "Petitioner") filed its petition for approval of its environmental compliance cost recovery adjustment ("ECCRA") pursuant to the Commission's Orders in Cause No. 42170, issued November 14, 2002 and Cause No. 42700, issued November 30, 2004. Also, on December 18, 2009, Petitioner filed the direct testimony and exhibits of David Kehres, Thomas W. Moore, Greg Daeger, Craig Forestal, Dwayne Burke and James Cutshaw. The Office of Utility Consumer Counselor ("OUCC") filed the testimony of Wes R. Blakley and Cynthia M. Armstrong in this Cause on February 3, 2010. Petitioner filed the rebuttal testimony of Mr. Cutshaw on February 5, 2010.

Pursuant to public notice duly given and published as required by law, proof of which was incorporated into the record by reference and placed in the Commission's official file, a public hearing in this Cause was held on February 10, 2010, at 9:30 a.m., EST, in Judicial Courtroom 224, National City Center, 101 W. Washington Street, Indianapolis, Indiana. At the hearing Petitioner and the OUCC appeared by counsel and offered their prefiled testimony and exhibits which were admitted into evidence without objection. IPL's Responses to the Commission's February 8, 2010 Docket Entry was also admitted into evidence without objection. No other party or members of the general public appeared.

Based upon the applicable law and the evidence of record, the Commission now finds:

1. **Commission Jurisdiction and Notice.** Proper notice of the hearing in this Cause was given as required by law. IPL owns and operates an electric utility and is subject to the jurisdiction of this Commission as provided in the Public Service Commission Act, as amended, IC 8-1-2, *et seq.* Thus, the Commission has jurisdiction over IPL and the subject matter of this Cause.

2. **Applicant's Characteristics.** IPL is an electric generating utility and is a corporation organized and existing under the laws of the State of Indiana, having its principal office at One Monument Circle, Indianapolis, Indiana. IPL is engaged in rendering electric public utility service in the State of Indiana and owns, operates, manages and controls, among other things, plants and equipment within the State of Indiana used for the production, transmission, delivery and furnishing of such service to the public.

3. **Proposed Rider Adjustment.** The Commission's November 14, 2002 Order in Cause No. 42170 granted IPL a Certificate of Public Convenience and Necessity ("CPCN") for Petitioner's projects to comply with new environmental regulations restricting the emission of nitrogen oxides ("NOx") from Petitioner's generation units ("November 14 Order"). The November 14th Order also approved use of the ECCRA and procedures for implementing the ECCRA, including standardized forms for purposes of submission of information. On February 28, 2007 in Cause No. 42170-ECR-8, the Commission approved modifications to Petitioner's CPCN to include the installation of a sodium bisulfite ("SBS") injection system for the Selective Catalytic Reduction ("SCR") projects for Petersburg Units 2 and 3 to mitigate sulfur trioxides ("SO_3") emissions and for recovery of the cost of the SBS injection system.

The Commission's November 30, 2004 Order in Cause No. 42700 approved modifications to the CPCN to construct a Flue Gas Desulphurization ("FGD") system at Harding Street Unit 7 and FGD Enhancements on Petersburg Unit No. 3 (the "November 30 Order"). On August 31, 2005 in Cause No. 42170-ECR-5, on August 16, 2006 in Cause No. 42170-ECR-7 and on February 28, 2007 in Cause No. 42170-ECR-8, the Commission approved modifications to IPL's CPCN regarding IPL's cost estimates of the CCT projects. On September 13, 2007, in Cause No. 42170-ECR-9, the Commission found that the catalyst replacement and refurbishment expenditures incident to the operation of IPL's Selective Catalyst Reduction equipment are an ongoing cost appropriate for recovery in IPL's ECR semi-annual proceedings.

The projects approved pursuant to the Commission's November 14 and November 30 Orders and our subsequent orders in various ECR proceedings, concern the first step of IPL's Multi-Pollutant Plan. The Commission's April 2, 2008 Order in Cause No. 43403 approved a modification to the CPCN to construct FGD Enhancements on Petersburg Unit No. 4 and to install mercury monitors ("April 2 Order") to allow IPL to reliably and economically achieve compliance with the Environmental Protection Agency's ("EPA") air emission regulations. Steps 1 and 2 are collectively referred to as the "Multi-Pollutant Plan". In this Cause, Petitioner seeks Commission approval of an ECCRA to earn a return on construction costs incurred as of November 30, 2009, and to timely recover depreciation and Operation and Maintenance ("O&M") expenses.

4. **Status of Petitioner's Construction of Qualified Pollution Control Property ("QPCP").** Petitioner submitted testimony regarding the status of the Clean Coal Technology ("CCT") projects. IPL Witness Kehres provided the final NOx project costs for the original

projects approved in Cause No. 42170. He also stated that the SBS Injection Systems have not been completed. The completion date for the SBS Injection Systems has not been determined as these projects have been suspended. He stated that the final costs for those projects will be reported once they are completed and placed into service.

Witness Kehres testified that there were two Multi-Pollutant Plan projects that were approved in the November 30th Order. The first was enhancement to the existing flue gas desulphurization ("FGD") system on Petersburg Unit 3. He stated that the FGD system on Petersburg Unit 3 has been completed and that the project entered service on June 24, 2006. Witness Kehres testified that the performance of the upgraded scrubber has exceeded the original design emission target of 0.4 lbs. SO_2/MMBTU as the current emissions from Unit 3 are less than 0.2 lbs. SO_2/MMBTU. This better than expected performance will likely result in lower future SO_2 compliance costs as fewer SO_2 emissions allowances will be consumed on Unit 3.

The second Multi-Pollutant Plan project is construction of a new FGD system for Harding Street Station Unit 7. Witness Kehres testified that the Harding Street Unit 7 FGD went into service on September 17, 2007, although some construction/punchlist completion activities continue. He explained that the installation of hydroclones to the gypsum dewatering system is complete and operating as expected. The hydroclones were placed into service on July 8, 2009. Mr. Kehres stated that the gypsum quality is now meeting the specifications for use in wallboard production. He stated that other work completed recently includes the installation of access platforms to several components, installation of a weather enclosure at the limestone receiving hopper, installation of control valves to improve system reliability, and improvements to site drainage in the FGD area. He stated that installation of additive injection ports on the ductwork upstream and downstream of the SCR system was also completed. These ports will be used for testing and for the injection of performance additives should they be required for improved precipitator performance.

Mr. Kehres stated that IPL has also received final certification from the Indiana Department of Environmental Management ("IDEM") for the continuous Particulate Matter Continuous Emissions Monitoring System ("PM CEMS") on the Harding Street Unit 7 scrubbed stack and that the system was placed into service on June 4, 2009. He stated the PM CEMS is performing as expected and has resulted in lower reported particulate emissions and significantly fewer units derates due to measured opacity levels upstream of the FGD system. However, IPL will be required to install a redundant PM CEMS in the Unit 7 scrubbed stack to meet the IDEM requirements for a continuous monitoring system.

Mr. Kehres stated that the remaining work on Harding Street Unit 7 FGD includes the installation of a stack liner protection system on the FGD bypass stack and the installation of winterization hardware and engineering controls on the SO_3 removal system. He also stated that in the next 6 to 12 months, IPL plans to complete the installation of a redundant SO_2 monitor on the FGD inlet to improve the control of the FGD system when the current monitor is unavailable due to failure or calibration; installation of an access opening to the FGD recycle piping header for personnel to enter for inspection and/or repair; and continued installation of platforms to improve access to various FGD equipment.

Mr. Kehres stated that a borosilicate block lining system is proposed for installation on the existing steel liner of the Harding Street Unit 7 FGD bypass stack. He stated that the original stack on Unit 7 is now used as the FGD bypass stack since a new stack was installed as part of the FGD project. The bypass stack only passes flue gas infrequently such as during boiler start-ups prior to the FGD system being placed into service or during times when the FGD system is unavailable for operation. He stated that the bypass stack allows for full unit operation independent of the Unit 7 FGD system. He noted that the existing steel liner in the bypass stack is open to the elements and must be modified to protect it from the corrosion it will experience over time due to ambient moisture. Prior to the FGD system coming online, this stack liner was in operation the vast majority of the time operating at temperatures near 300 degrees F which protected the carbon steel from moisture related corrosion.

Mr. Kehres stated that the borosilicate block lining system is the least expensive system that IPL is aware of that can provide the corrosion protection needed and withstand an operating temperature of 300 degrees F which occurs when the bypass stack is placed into operation as well as the 700 degrees F temperatures that can exist during certain boiler upsets. He stated that IPL has successfully used the borosilicate block lining system in this exact application at its Petersburg facility. Mr. Kehres stated that the block lining of the bypass stack was always anticipated but could not be installed earlier in the FGD project as the installation takes 7-8 weeks to complete and an outage of this length was not required for the FGD to be placed in-service. Thus, the block lining work was deferred to coincide with the next scheduled eight week Unit 7 turbine overhaul outage which is planned for the fall of 2010. Mr. Kehres stated the estimated cost of the block lining system is $4.0 million and will be completed within the current project cost estimate.

Mr. Kehres also described the winterization work and engineering controls that are planned for the SO_3 removal system (SBS System). He stated the SBS injection equipment is located in the SCR structure just downstream of the SCR reactor duct and that this area of the SCR structure is prone to severe icing during the winter months from the cooling tower plume which blows through the outdoor SCR. He stated that this icing problem has become more of a safety issue now that both SBS and SCR are operated year round. Mr. Kehres stated that the occasional icing was tolerated in the past as the SCR was out of service during the winter months and operating personnel were not required to work as often in the icy areas of the SCR structure. He stated that IPL plans to install enclosures and/or wind walls and heating to prevent ice formation on the necessary work areas. The estimated cost for this winterization work, which will be installed over the next 18-24 months, is $1.1 million and this work will be completed within the current project cost estimate.

Mr. Kehres also stated that a Breen Probe analyzer system is planned to be installed downstream of the SBS injection lances and upstream of the electrostatic precipitators to measure the SO_3 content of the flue gas after the reaction with the SBS reagent. Currently the SO_3 levels are not measured by on-line instrumentation. He stated that the Breen Probe analyzer will be used to better control the injection rate of SBS reagent which will reduce the probability of fouling the air preheater and increase the precipitator collection efficiency by controlling the amount of SO_3 entering the precipitator. Currently the target SBS reagent injection rate is calculated based upon unit operating characteristics and fuel analysis. Mr. Kehres stated that a second Breen Probe analyzer system is also planned for installation to measure ammonia slip in the SCR system and provide feedback control for the ammonia injection system. The feedback control on the ammonia reagent injection system will improve NO_x emissions, reduce ammonia consumption and reduce the air heater fouling potential that results from excess ammonia slip in the SCR. He stated that the existing SCR control system measures NO_x downstream of the SCR and provides for control of the ammonia reagent based upon SCR outlet NO_x levels. Mr. Kehres stated that this original control system has proven to be a maintenance problem which results in manual control of the ammonia reagent for long periods of time. The cost for the two Breen Probe analyzer systems is estimated at $360,000 and will be completed within the current project cost estimate.

Witness Burke testified that since commencement of operation, the Harding Street Unit 7 FGD scrubber is removing at least 97% of the SO_2 from the Unit 7 flue gas. To quantify this SO_2 reduction, the pre-scrubber SO_2 emission rate was 2.46 lb/MMBtu of SO_2 and the post-scrubber SO_2 emissions rate is now 0.08 lb/MMBtu of SO_2. Overall SO_2 emissions at Harding Street have decreased from 31,000 tons per year to 1,000 tons per year. Therefore, a significant reduction in SO_2 emissions has occurred at Harding Street due to the Unit 7 FGD scrubber. In addition to the SO_2 reductions, there have been reductions in PM/PM10/PM2.5 and ionic mercury due to the Harding Street Unit 7 FGD. IPL believes the reduction in PM2.5 will assist Marion County in the PM2.5 attainment strategy. Mr. Burke stated that since the Unit 7 start-up date, September 17, 2007, the Harding Street Unit 7 FGD experienced an increase in opacity readings causing IPL to frequently de-rate the unit.

Mr. Burke stated that IPL attributes a percentage of the increase in opacity readings to the utilization of a Continuous Opacity Monitor System ("COMS") located upstream of the Harding Street Unit 7 FGD. Opacity is measured by the COMS in the duct work, and not at the stack exit, which is where the opacity limit applies. Harding Street operated its COMS for the scrubbed stack associated with Unit 7, in duct work between the Unit 7 Electrostatic Precipitator ("ESP") and the recently installed Unit 7 FGD. The location of the COMS was found to be less than ideal for obtaining data representative of actual particulate matter ("PM") emissions as PM is removed in the scrubber downstream of the opacity monitor. Thus, actual PM emissions discharged at the scrubbed stack are lower than that represented by the current opacity monitor.

Mr. Burke testified that on September 10, 2008, IPL submitted a letter to IDEM requesting to install, certify, and operate a PM CEMS in place of the COMS as an alternative method to monitor particulate emission rates from the Unit 7 FGD scrubbed (wet) stack at IPL's Harding Street Generating Station. Mr. Burke testified that on November 7, 2008, IDEM issued Commissioner's Order (#2008-02) and Variance Decision to IPL regarding approval to install, certify and operate a PM CEMS in lieu of COMS for Harding Street Unit 7 scrubbed stack. The variance became effective on November 25, 2008. Since the issuance of the Commissioner's Order (#2008-02) and Variance Decision, IPL purchased, installed, certified and operated a PM CEMS for the Unit 7 scrubbed stack. He stated that the capital cost associated with the installation of a PM CEMS is $573,000 with an estimated annual O&M expense of $39,000. Mr. Burke stated that IPL initiated the operation of the certified PM CEMS associated with the Harding Street Unit 7 scrubbed stack on June 24, 2009 and it has operated for a complete quarter, July 1, 2009 through September 30, 2009. He stated that IPL is now able to directly determine compliance with 326 IAC 6.5 (Particulate Matter Emission Limitations) by continuously measuring PM emissions at the stack exhaust point in lieu of indirect PM compliance determination via opacity readings at the in-duct work prior to the scrubber. He stated that during Q3 2009, IPL demonstrated continuous compliance with the PM emission limitation of 0.10 lb/MMBtu. In addition, IPL was able to determine the percent reduction of

PM emissions associated with the addition of the FGD and SBS. IPL has estimated that the overall percent PM emission reduction is 85% pre to post-FGD configuration.

Mr. Burke testified that the Harding Street Unit 7 PM CEMS is required to operate in a manner such that IPL can show continuous compliance with the unit's PM limitation and this is not possible when the PM CEMS is not properly functioning for any reason. In addition, IDEM stated that the PM CEMS must obtain at least 97% valid PM emissions data at all times when the boiler is in operation. Examples which can cause invalid data readings includes, but are not limited to: CEMS breakdowns, calibrations, and repairs. The PM CEMS is a new technology and there is limited historical information available relative to its operation performance. Thus, the HS Unit 7 PM CEMS vendor provided IPL with a PM CEMS operational guarantee of 90%. Based on the unexpected issues associated with operating this new technology in combination with the above listed issues which can cause invalid readings, it is not possible for IPL to ensure the PM CEMS operates at least 97% percent of the time as required by IDEM. Mr. Burke stated that IPL can purchase, install, certify and operate a redundant (back-up) PM CEMS to ensure continuous compliance with the PM limitation. Mr. Burke explained that IDEM applies its standard policy of 3% CEMS downtime (97% CEMS uptime requirement) for attainment status to scrubbed stacks, thereby requiring IPL to operate redundant PM CEMS in order to comply with the monitoring requirements for continuous emissions monitors. The estimated capital cost is $573,000 and the estimated annual O&M is $39,000 per year. The overall benefit associated with operating a redundant PM CEMS is to obtain 97% or more of valid PM emissions data associated with the HS Unit 7 scrubbed stack. Mr. Burke stated that state law authorizes fines up to $25,000 per day per violation. The amount of the fine depends on the magnitude of the violation, the potential harm to human health and the environment, the economic benefit gained by the violator by not complying and the violator's efforts to achieve compliance.

Mr. Kehres testified that there are two additional Multi-Pollutant Plan projects that were approved in the Commission's April 2 Order; Petersburg Unit 4 FGD Enhancements and Mercury Monitoring Systems. He stated that IPL decided to delay the Petersburg Unit 4 FGD Enhancements project and that the Petersburg Unit 4 turbine overhaul outage was rescheduled for 2011 to match the revised project completion schedule for the FGD Enhancements. He stated that engineering and procurement activities are continuing to support the revised project completion date. He stated that as of November 30, 2009, engineering on the Petersburg Unit 4 FGD Enhancements project was 65% complete and procurement was 21% complete. Construction activities are planned to begin during the first quarter of 2010.

As to recent developments relating to the Federal Clean Air Interstate Rule ("Federal CAIR"), Mr. Burke explained that on July 11, 2008, the D.C. Circuit Court issued an opinion vacating CAIR. On September 24, 2008, EPA and three (3) other petitioners filed with the U.S. Court Appeals (D.C.) a petition seeking rehearing and reinstatement of the Federal CAIR rule. EPA asked the court to reconsider its decision to vacate CAIR. On October 21, 2008, the D.C. Circuit Court asked the parties to the CAIR litigation if the court should vacate the rule or stay the mandate while the EPA revises CAIR which would allow CAIR to still be in effect. On November 18, 2008, EPA filed a brief stating that it prefers that the D.C. Circuit Court remand its initial decision. However, EPA preferred, at a minimum, that the D.C. Circuit Court stay its mandate and allow the rule to go into effect for a finite period of time until EPA revises the rule. Mr. Burke stated that on December 23, 2008, the Court granted EPA's petition to the extent that the case be remanded without vacatur for the agency to conduct further proceedings consistent with the Court's opinion in the case, and denied the remaining petitions. The Court determined that, notwithstanding the flaws of CAIR, remanding it without vacatur was preferable to retain the environmental benefits of the rules. As a result, CAIR became effective on January 1, 2009 for the annual NOx program.

Mr. Burke described the CAIR NOx emission reduction requirements that became effective on January 1, 2009. He stated that CAIR NOx required year round compliance as of January 1, 2009. This is referred to as annual NOx compliance program. This new requirement is in addition to the summer ozone season requirements which have been in effect since the NOx SIP call. Further, CAIR NOx is phased in through two phases. Phase I became effective on January 1, 2009 with the effective emission reduction requirements of 0.15 lb / mm BTU remaining the same as the EPA NOx SIP call. Phase II is scheduled to go into effect on January 1, 2015 with the effective emission reduction requirements being lowered to 0.125 lb / mm BTU. He explained that IPL met the 2009 CAIR NOx ozone season primarily through the successful operation of its NOx pollution control equipment. In addition, IPL completed adding additional layers of SCR catalyst for Petersburg Unit 2, Petersburg Unit 3, and Harding Street Unit 7 which lowered the NOx emission rates on those units as described in IPL's ECR 10 proceeding. Mr. Burke stated that there are other changes which occurred in 2009 that changed the IPL NOx emission allowance position. He stated that IPL successfully operated its NOx equipment year round in 2009 as of the filing date. He noted that economic conditions decreased demand for electricity not only in Marion County but throughout the country. As a result of this decreased demand, IPL emissions were reduced in 2009 as its units were not dispatched in a manner consistent with historical unit operations. He stated that this led to decreased emissions system-wide and a larger bank of NOx annual and ozone season allowances than what has been seen in the past. Mr. Burke stated that IPL is projected to be long just over 1,000 ozone seasonal NOx allowances and 500 annual NOX allowances. He stated that IPL plans on selling the excess emission allowances over such time as the markets allow. However, due to the number of allowances, IPL will need to sell in smaller increments in order to ensure it does not negatively impact the thinly traded emission allowance markets. Mr. Burke stated that IPL successfully completed its first transaction on November 24, 2009 by selling 230 seasonal ozone NOx allowances at a market price of $105. As a result of a very thinly traded market and relative low prices, IPL will continue to evaluate the merits of banking both seasonal and annual NOx allowances for 2010.

Mr. Burke stated that since the beginning of 2009, the NOx annual allowance market has traded between $550/ton and $4250/ton whereas the NOx ozone season allowance market has traded between $100/ton and $625/ton. The volatility for both allowance markets increased from the past as a result of two actions. First, the D.C. Circuit granted rehearing only to the extent that it remanded the rules to EPA without vacating them on December 23, 2008. The December 23, 2008 ruling leaves CAIR, including the CAIR trading programs, in place until EPA issues a new rule to replace CAIR within the next two (2) years. EPA is continuing to record allowance allocations under the CAIR NOx trading program, in some cases for years beyond the estimated two-year period for promulgation of a replacement rule. EPA is taking these actions consistent with the State or Federal rule that applies. When making any decisions on, and arrangements for, purchasing or selling CAIR NOx allowances, EPA has indicated that prospective buyers and sellers should keep in mind the potential impact that the status of CAIR and any replacement rule may have on the value of the allowances, particularly those allocated for years after the expected finalization of a replacement rule. EPA's continued recording of CAIR NOx allowances does not guarantee or imply that any allowances will continue to be usable for compliance after a replacement rule is finalized or that they will continue to have value in the future. In short, the remand does little to relieve the uncertainty created by the vacatur. The court's decision remains unchanged; the requirement on the Agency to rewrite the rule remains unabated; and the value of credits associated with the rule is still exceedingly speculative. Second, the current world financial crisis has led to speculative participants fleeing the market except those who need the allowances for NOx annual and ozone season compliance appear to be participating at this time as evidenced by low trade volumes. Taken together these activities have led to illiquid markets which in fact don't accurately reflect a true market. However, once CAIR is finalized the markets will likely stabilize. At that time, IPL will provide an update to the Commission on the emission allowance market.

Mr. Burke summarized the current SO_2 regulation. He stated that currently SO_2 regulations are dictated by the Clean Air Act Amendments of 1990 ("CAA"). The requirements are a cap and trade system with IPL being allocated allowances based upon historical heat input. The SO_2 regulations have been the same since CAA and will remain the same through December 30, 2009. He stated that IPL pursued a number of options to maintain compliance with the existing CAA. First, as approved in Cause No. 42700, IPL successfully upgraded the emission reduction capability of Petersburg ("Pete") Unit 3 Flue Gas Desulfurization ("FGD") and installed and commenced operation of a FGD on the Harding Street ("HS") Unit 7 in October 2007. Second, IPL utilizes existing FGDs on Pete Unit 1 and Pete Unit 2 and low sulfur coal on Eagle Valley ("EV") Units 3 through 6 and HS Units 5 and 6. Third, IPL supplements its SO_2 compliance with the purchase of allowances on the open market.

On January 1, 2010, Phase I of the new CAIR becomes effective for SO_2. The Phase I emission reduction requirement equates to a 50% reduction in the current emission rate (0.6 lb/MMBtu) as allowances will be required to be submitted on a 2:1 ratio. The 50% emission reduction and the submittal of allowances on a 2:1 basis will remain in effect from 2010 through 2014. Then, beginning on January 1, 2015, Phase II becomes effective for SO_2 under CAIR. This will require an emission reduction requirement of an additional 30%. The additional 30% reduction will result in the submittal of SO_2 allowances at a rate of 2.86:1.

Mr. Burke stated that IPL is pursuing a number of options to not only prepare for and meet the new, more stringent CAIR requirements which take effect on January 1, 2010, but also for current compliance with the existing CAA. In order to comply with CAIR Phase I SO_2 requirements beginning January 1, 2010, IPL recently upgraded the emission reduction capability of Pete Unit 3 FGD and installed and commenced operation of a FGD on the HS Unit 7 in October 2007 as approved in Cause No. 42700. In order to meet CAIR Phase II SO_2 requirements beginning on January 1, 2015, IPL is planning to upgrade the removal performance of the Pete Unit 4 FGD in the fall of 2011 as approved in Cause No. 43403. The purpose of the FGD upgrade is to increase the SO_2 removal efficiency of the unit to 95%. The increase to the SO_2 removal efficiency will result in an estimated additional removal of 14,000 tons per year of SO_2. With the successful completion of the Pete Unit 3 FGD and the HS Unit 7 FGD installations, IPL is expected to materially meet the SO_2 emission reduction requirements of Phase I of CAIR. In addition, with the successful completion of the upgrade of the Pete Unit 4 FGD, IPL is expected to materially meet the SO_2 emission reduction requirements of Phase II of

CAIR. IPL will supplement its compliance with the purchase of allowances on the open market, if needed.

Mr. Burke explained why IPL decided to move forward with the Pete Unit 4 FGD Enhancements project. He stated that the environmental landscape is changing rapidly for utilities, with significant impacts on electric utilities such as IPL whose base load generation is entirely coal fired. Within this transitional landscape, IPL continues to invest in its large generating units to keep them clean, reliable, and efficient. Moreover, as discussed elsewhere, more stringent environmental regulations are imminent with the question being "when" and not "if". As a result, IPL is moving forward with the Pete 4 FGD Enhancement project. These operational and pollution control improvements in combination with alternative energy resources will serve as the foundation to meet growing power demands while reducing emissions, preserving non-renewable energy sources, and decreasing environmental impacts.

Mr. Burke stated that EPA is "moving aggressively" to address interstate transport of NOx, SO_2 and particulate matter ("PM"), according to Assistant Administrator McCarthy. EPA plans to propose a new draft CAIR rule by early 2010, and to approve a final rule by early 2011. He stated that while the court made clear in *North Carolina v. EPA* that EPA cannot simply reinstate CAIR, EPA believes opportunities remain to include a trading regime in the new CAIR. EPA believes the D.C. Circuit opinion requires it only to address the problem of upwind states contributing to nonattainment in downwind states in the new trading system. EPA will consider a hybrid trading approach, which would consist of an interstate trading scheme plus plant-specific controls. EPA is also considering tighter trading regimes, such as regional or intrastate trading. EPA currently is investigating which states will be covered by the new CAIR and is unsure if the list of covered states will change. Mr. Burke stated that in addition to EPA action there are legislative activities at the Federal level which could lead to more stringent SO_2 emission reduction requirements. He stated that on August 7, 2009, Senator Carper (D-DE), along with Senator Alexander (R-TN), Collins (R-ME) and Klobuchar (D-MN) circulated draft multi-pollutant legislation titled the "Clean Air Planning Act of 2009 ("CAPA") which covers SO_2, NOx, and Mercury. The draft legislation may stand on its own or be inserted into the Greenhouse Gas bill. The draft legislation codifies CAIR through 2011 and then imposes stricter SO_2 emission limitations beginning in 2012. Mr. Burke stated that it is unclear what the new SO_2 emission limitation will be, but it is anticipated that pre-2012 allowances will carry-over for compliance but post-2011 allowances issued under Title IV of CAA, will not be carried-over for compliance. In 2012, 100% auction of allowances will occur in conjunction with regional trading.

Mr. Burke stated that there are other factors which lead to IPL's decision to upgrade the Pete Unit 4 FGD by the fall of 2011. He stated that IPL plans to upgrade the Pete Unit 4 FGD in conjunction with an upcoming planned maintenance outage in 2011 in order to ensure unit reliability and maintain the electricity needs of its customers. In addition, the upgrade of the Pete Unit 4 FGD will not only increase the SO_2 removal efficiency but also the removal efficiency of PM. IPL anticipates that the additional decrease in PM emissions as a result of the FGD upgrade will aid the State in demonstrating compliance with the new PM 2.5 NAAQS and Regional Haze, while also reducing interstate transport. Mr. Burke stated that at this time, it is unclear to IPL what type of trading program, if any, will be allowed under a CAIR replacement rule based on current legislative and EPA activities. IPL believes the most efficient and effective step to ensure compliance with a more stringent SO_2 regulation is to upgrade the Pete Unit 4 FGD. Mr.

Burke stated that the upgrade of the Pete Unit 4 FGE is still preferable to installing new SO_2 controls on other units. He stated that IPL's large coal-fired units, which consist of Pete Units 1 through 4 and HS Unit 7 ("Big 5 Units"), account for approximately 65% of IPL's 3,353 MW (net) of summer capacity. However these units account for approximately 85% of the annual energy produced to meet IPL's retail and wholesale demand. IPL's large coal-fired units have allowed IPL stakeholders to enjoy the benefits of being located in close proximity of the Illinois Basin Coal Reserves by maintaining a competitive fuel source. Installing or upgrading emission control devices at one of IPL's large coal-fired units will have a greater impact in reducing emissions compared to installing new controls on smaller units, such as HS Unit 5 and HS Unit 6 (100 MW each); and is also the most economically viable option. In addition, it is unclear to IPL at this time how more stringent SO_2, NOx and mercury regulations will impact the smaller units.

In Petitioner's ECR-8 proceeding, OUCC Witness Blakley proposed that IPL submit in subsequent ECR filings the monthly progress reports it receives from Advatech LLC, pursuant to Section 2.3.2 of the No Lien Agreement for Engineering Procurement and Construction ("EPC") services between IPL and Advatech LLC dated September 23, 2005. Petitioner agreed to submit such reports and Petitioner provided Petitioner's Exhibit DK-3, which included the only monthly Progress Reports received since its last proceeding. Mr. Kehres noted that this is the final monthly progress report for the project.

OUCC Witness Blakley testified that nothing came to his attention that "would indicate that Petitioner's calculation of estimated ECR adjustment factors for the relevant period is unreasonable."

Based on the evidence, we find that the costs incurred through November 30, 2009 for the CCT projects are reasonable and appropriate. We approve the construction work through November 30, 2009, and the reflection of such costs in the ECCRA.

5. Compliance with Applicable Requirements.

A. Amount of QPCP Construction Costs. 170 IAC 4-6-12 ("Section 12") requires Petitioner to make certain submissions as part of its prefiled written testimony and exhibits in support of its request for ratemaking treatment for its QPCP construction costs. Pursuant to Section 12(a), Witness Forestal sponsored Petitioner's Exhibits CF-2 NOx and CF-2 MPP, which set forth the construction costs as of November 30, 2009 for which Petitioner seeks ratemaking treatment in this Cause. This ECCRA includes recovery of costs approved in this Commission's prior orders in Cause No. 42170 and Cause No. 42700. Mr. Forestal stated that the projects approved in the April 2 Order must be under construction for at least six months prior to inclusion in the ECCRA and that projects approved in the Commission's April 2 Order would be included in a later ECCRA once this condition has been met. Mr. Forestal stated that in accordance with the settlement agreement which was approved in Cause No. 42170, the NOx Allowance Expense on Exhibit CF-2 NOX has been reduced by 80% of the net proceedings from IPL's sale of NOx allowances that occurred during the current filing period.

B. Rate of Return on Approved QPCP Construction Costs. Petitioner's Exhibit CF-1 NOx reflects the calculation of Petitioner's Gross Revenue Conversion Factors as approved in Cause No. 42170 utilizing an allowed rate of return of 8.00% and a gross rate for borrowed funds of 3.27%. Petitioner's Exhibit CF-1 MPP reflects the calculation of Petitioner's

Gross Revenue Conversion Factors as approved in Cause No. 42700 utilizing an allowed rate of return of 7.70% and a gross rate for borrowed funds of 3.65%.

C. **Recovery of Depreciation, Operation and Maintenance (O&M), and Proposed Treatment of Capital Maintenance Expenses**. Our November 14, November 30 and April 2 Orders, provide for the timely recovery of depreciation and O&M expenses. Petitioner's Exhibit CF-2 NOx and Petitioner's Exhibit CF-2 MPP included prospective depreciation and O&M expenses. Witness Forestal testified that the estimated O&M expenses were for ammonia and urea costs that will be consumed for the operation of the SCRs and SNCRs, limestone, chemicals and labor costs (including benefits) for the operation of the FGDs, as well as for maintenance of the equipment.

Mr. Forestal stated that IPL is also requesting recovery of capital maintenance expenditures as discussed by IPL Witnesses Daeger and Moore. He stated these are routine maintenance projects performed on environmental controls that are classified as capital according to FERC's USOA. IPL's financial practices and procedures are established to ensure proper compliance with the FERC USOA's treatment of asset acquisition, depreciation, transfer and disposition. Use of FERC's USOA assures the appropriate categorization of maintenance activities as either a capital item or an operating expense.

In its responses to the Commission's Docket Entry dated February 8, 2010, IPL explained more fully the reasons for capitalizing these items, instead of including them in O&M expense and cited from FERC Code of Federal Regulations Part 101 Section 10, Subsections A and B. IPL stated that the items described in Mr. Forestal's testimony as capital maintenance are replacements of damaged equipment and not considered a substantial betterment compared to the original equipment being replaced. IPL stated each of the items is identified on IPL's property units listing and therefore must be capitalized. It also stated that were it not for the items being units of property, they would have been expensed as O&M. IPL stated that these maintenance activities were not included in the original CPCN granted for these projects because they were not incurred as part of the initial installation of the equipment, but rather are included as on-going maintenance of the equipment.

Mr. Forestal stated that Exhibits CF-2 NOx and CF-2 MPP were changed to add lines for the capital maintenance expenditures and retirements of environmental controls. OUCC Witness Blakley stated that Petitioner's inclusion of testimony highlighting the changes in its schedules is exactly what is needed in order to understand the changes in the exhibits.

IPL Witness Moore provided a review of the implementation of IPL's Selective Catalytic Reduction ("SCR") Catalyst Management Program and provided information regarding the replacement and refurbishment expenditures which will be incurred incident to operation of IPL's SCR systems at Petersburg Unit 2, Petersburg Unit 3 and Harding Street Unit 7 for which recovery will be sought in future proceedings. He also presented updated and new information regarding the continuing processes for the SCR Catalyst Management Program and SCR System modifications to be undertaken as a result of year round operation of the SCR Systems presently installed, as well as updates for the Petersburg Unit 3 FGD System and the SBS Injection System. Mr. Moore stated that previously several system modifications and additions were identified to provide safe and efficient NOx reduction throughout the year. He explained that during 2009, IPL made numerous equipment modifications and additions to the Petersburg Unit

2 and Unit 3 SCR Systems. He stated that the next scheduled outages for these Units are in the Fall of 2010 and the Spring of 2011, respectively. For this reason, any activities planned for the Spring of 2010 will be limited to modifications and additional external to the SCR reactors.

Mr. Moore identified and described the equipment modifications and additions. He stated that while most of the modifications and additions identified in IPL's ECR-13 proceeding were completed and placed in service, a few remain to be completed during the next six month period (installation of permanent vacuum lines, addition of protective shelters at the SCR structures, and installation of a heated water source at the emergency shower and eyewash located at the ammonia receiving station).

Mr. Moore stated that other modifications or additions necessary for the safe operation and maintenance of the SCR Systems have been identified for the Petersburg SCR Systems and are designated for implementation during the first half of 2010. He stated that during the first half of 2010 IPL will be investigating additional modifications to the SCR Systems.

Mr. Moore also acknowledged a substantive change for the planned in-service date for the SBS Injection System for Petersburg Units 2 and 3. He stated that although a new planned in-service date has yet to be determined, the patent holder and developer of the SBS Injection System have continued to provide process modifications and enhancements for increased process efficiency and reduced capitalized costs. He stated that IPL continues to work with the developers to optimize the injection locations and process parameters for the Petersburg application. He stated that these advancements have allowed the process developers to conduct successful testing of the equipment modifications and injection location most suitable for the Petersburg Units. In addition, early testing has indicated the process to be beneficial for the removal of mercury when used in conjunction with an SCR and a wet limestone scrubber. This is the equipment configuration planned for Petersburg Unit 2 and Unit 3. Due to these developments, IPL is suspending its planned stand along SBS Injection System to conduct further analysis to optimize the use of this technology and to consider whether its installation should be coordinated with IPL's future mercury mitigation program.

Mr. Moore stated that now that the SCR Systems have accumulated approximately 22,000 hours of operation, it is prudent to expect failures and plan for replacement of critical parts and equipment. The types of equipment most likely to experience these conditions are: analyzers, pumps, valves and piping and acoustic horns. The anticipated life of this equipment will vary with usage and severe conditions experienced. Without specific definition of a schedule, capitalized maintenance of unitized equipment is forecast for each annual period of operation.

Mr. Daeger discussed on-going capital maintenance projects for IPL's Harding Street and Eagle Valley Generating Stations emissions control equipment, including a description of anticipated maintenance for which IPL is seeking recovery of costs in this proceeding. Mr. Daeger stated that the emission controls equipment in service at Harding Street and Eagle Valley Generating Stations requires periodic maintenance to ensure reliable operations and satisfactory emission removal efficiency. The service conditions in which this equipment operates is detrimental to equipment integrity, for the constituents of flue gas and chemical processes are very corrosive, erosive and otherwise detrimental to equipment. Therefore, periodic maintenance activities, including equipment replacement, are necessary to sustain reliable, efficient operation. Mr. Daeger agreed with Mr. Forestal that a portion of the routine maintenance activities performed on the Harding Street and Eagle Valley Generating Stations' environmental controls meet the criteria of a capital expenditure, in accordance with the Federal Energy Regulatory Commission's Uniform System of Accounts.

Mr. Daeger stated that typical capital maintenance projects include, but are not limited to valve, piping, mist eliminator, tank lining, expansion joint, duct lining, motor, air preheater basket, and computer software/hardware replacement. The need for such replacement is determined through condition assessment activities, including the inspection, testing, and analysis performed during normal operation and planned generating unit outages. Unplanned equipment failures also result in the immediate need to perform capital maintenance activities. Mr. Daeger described the two capital maintenance projects completed in the past 6 month period. He also identified the capital maintenance projects planned for the next 6 month period and the Fall 2010 planned outage.

Mr. Moore stated that the enhancement project to the existing FGD System on Petersburg Unit 3 has been completed and the project entered service on June 24, 2006. A recent inspection of the stack liner, which was installed during the Unit 3 Enhancement project, revealed some problem areas with the alloy wallpaper on upper sections of the stack liner. The alloy wallpaper had become detached from the carbon steel liner in certain areas and was repaired during a recent outage. The cost for this repair was $225,984 and this cost is included in the expenditures for which recovery is sought in this proceeding. The work was capital in nature and is included as capital maintenance on the accounting schedules.

At the hearing held in this Cause, Mr. Forestal responded to questions from the Bench related to the applicability of FERC Code of Federal Regulations Part 101 Section 10, Subsection C, which states that items that are not considered substantial additions should be charged to maintenance expense. Mr. Forestal explained that the items included in the filing as capital maintenance are considered substantial additions because each is considered a unit of property. Mr. Forestal also explained that the capitalized costs may also include incremental labor costs consistent with an earlier section in the FERC CFR which discusses the costs that should be capitalized, which includes labor and other materials. FERC CFR Part 101, Section 9. Mr. Forestal testified that IPL is depreciating these capitalized maintenance costs in the ECCRA filing in exactly the same manner it does on its books and records for its other assets.

The Commission understands that the capitalized maintenance costs replace existing units of property and that Petitioner's Exhibits CF-2 NOx has been modified to separately reflect these costs and the retirements. We note that footnote (5) on Petitioner's Exhibit CF-2 NOx states depreciation expense does not include depreciation on retired assets. We further note that while CF-2 MPP has a line item dedicated to retirements, no retirement amounts were shown, although capital maintenance was included.

Going forward, IPL shall provide additional support for its treatment of "capital maintenance" items as substantial additions. While IPL explained that it capitalized these items because they are considered units of property, FERC CFR Part 101, Section 10(A) states that "all property will be considered as consisting of (1) retirement units and (2) minor items of property." Accordingly, IPL must more fully demonstrate that "capital maintenance" items are substantial enough to constitute a "retirement unit" in order to be treated as a capital expense; otherwise, pursuant to FERC CFR Part 101, Section 10(C), replacements or additions of minor items of property that do not constitute substantial additions shall be charged to the appropriate maintenance expense account. While the Commission approves the proposed treatment of capital maintenance expense in this Order, we do so here given the relatively small monetary amount involved and the expedited nature of the ECR proceeding; as noted above, the Commission will require further explanation and analysis on this issue before the Commission approves proposed capital maintenance expense.

D. <u>Revenue Requirement</u>. Section 12(5) requires Petitioner to submit evidence regarding the derivation of its revenue requirement, including tax calculations, associated with the ratemaking treatment for the QPCP construction costs. Petitioner's Exhibit CF-1 NOx and Petitioner's Exhibit CF-1 MPP provide this information. Petitioner's Exhibit CF-2 NOx and CF-2 MPP provide details of the construction costs which have been incurred through November 30, 2009. Witness Forestal stated that the CCT projects for which IPL is seeking recovery had been under construction at least six months, including modifications to the projects that are necessary for year round operation, at a cost of $477.3 million, including AFUDC through November 30, 2009. Petitioner's Exhibit CF-2 NOx and Petitioner's Exhibit CF-2 MPP indicate that the total ECR-14 revenue requirement associated with QPCP construction costs as of November 30, 2009 is $20.489 Million.

Mr. Forestal explained that IPL also included projected depreciation and O&M associated with the CCT controls that are now in-service for the billing period of March 2010 through August 2010. The amount of depreciation expense that is included in ECR-14 is $14.4 million, and the amount of O&M included in ECR-14 is $7.4 million. Petitioner's Exhibit JC-2 demonstrates that the jurisdictional revenue requirements applicable to ECR-14 are $42.874 Million.

IPL reconciled estimated expenses and revenues to actual for the ECR-12 period of March 2009 through August 2009 resulting in a total variance of $3,091,113 (Petitioner's Exhibits CF-3, CF-4 and CF-5).

E. <u>Net Operating Income for Fuel Adjustment Clause</u>. Pursuant to 170 IAC 4-6-21, Petitioner shall add the approved return on its QPCP to its net operating income authorized by the Commission for the purposes of IC 8-1-2-42(d)(2) and IC 8-1-2-42(d)(3) in all subsequent Fuel Adjustment Charge proceedings. However, the Commission requires that, for purposes of computing the authorized net operating income for IC 8-1-2-42(d)(2) and IC 8-1-2-42(d)(3), the jurisdictional portion of the increase return shall be phased-in over the appropriate period of time that the Petitioner's net operating income is affected by this earnings modification resulting from the Commission's approval of this QPCP Construction Cost Rider.

F. <u>Allocation of Jurisdictional Revenue Requirement</u>. 170 IAC 4-6-15 provides that a utility's QPCP jurisdictional revenue requirement should be allocated among the utility's customer classes in accordance with the allocation parameters established in the utility's last general rate case. In accordance with Section 12(6), Petitioner's Exhibit JC-2 demonstrates the allocation of the QPCP construction cost revenue requirement among the utility's customer classes. Petitioner's allocation factors are from Petitioner's most recent electric rate case (Cause No. 39938) approved August 24, 1995.

G. Amount of Rider Adjustment. In Petitioner's Exhibit CF-3, the following ECCRA rate for each customer class was proposed:

$0.006806	per KWH for Rate RS, CW (with associated Rate RS service)
$0.009882	per KWH for Rates SS, SH, OES, UW, CW (with associated Rate SS service)
$0.005380	per KWH for Rates SL, PL, PH, HL

H. Approval of Rider Adjustments. The Commission finds that Petitioner has complied with the rules and procedures applicable to its request, including the requirements of 170 IAC 4-6, the November 14 Order, the November 30 Order, the April 2 Order and our subsequent orders regarding the Rider. The Commission further finds that the proposed Rider Adjustments are properly calculated. Therefore, the Commission finds that the Rider Adjustments contained in Petitioner's Exhibit CF-3, as shown in Petitioner's Exhibit A, should be approved.

6. Modification of Certificate of Public Convenience and Necessity ("CPCN"). Pursuant to Ind. Code § 8-1-8.7-7, which provides that the Commission shall at the request of a public utility maintain an ongoing review of the construction of CCT as the construction proceeds, and our November 14, November 30 and April 2 Orders, the Commission is reviewing IPL's construction of its CCT projects. The Commission must hold a public hearing before it may approve or deny a proposed increase in the cost estimates for the implementation, construction or use of CCT. In Cause Nos. 42170, 42700 and 43403, IPL requested ongoing review, which is conducted on a semi-annual basis.

Petitioner's Exhibit DK-2 shows the projected in-service dates for the implementation of IPL's Multi-Pollutant Plan projects and the estimated total project cost of compliance, by project, for each of IPL's generating facilities where Multi-Pollutant Plan projects are being installed. Petitioner's Exhibit CF-2 MPP provides details of the construction costs which have been incurred through November 30, 2009. IPL Witness Kehres testified that during the detailed engineer phase of the Petersburg Unit 4 FGD Enhancements project several design changes have been made that have affected the overall project cost estimate.

Mr. Kehres stated that the more significant design changes to the Petersburg Unit 4 FGD Enhancements project including changes to:

(a) Gypsum Dewatering System;

(b) Gypsum Storage Building;

(c) Replacement of scrubber tank agitators;

(d) Booster fan upgrade

(e) Mist eliminator upgrade

(f) Absorber tower inlet;

(g) Absorber tray, spray headers, and feed and quench piping;

(h) Water supply to new limestone ball mill;

(i) Limestone slurry supply pumps;

(j) Interconnection with existing dewatering system

(k) Electrical System Upgrades:

(l) Indiana Building Code Changes; and

(m) Engineering & Procurement Costs.

In addition, Mr. Kehres stated that IPL was able to reduce its original project cost estimate for Owner's Costs such as project management and construction management by $1.3 million and the amount of contingency in the revised project cost estimate by $3.9 million. The above changes result in a revised project cost estimate of $119.9 million. This revised cost is included in Petitioner's Exhibit DK-2.

Ms. Armstrong agreed with the necessity of the design changes. She stated that the OUCC recognizes that IPL relies on both its internal and external engineering staff to review existing project design and make changes as needed. Ms. Armstrong explained that one potential benefit of IPL continuing the Petersburg 4 FGD Enhancement would be a possible reduction in mercury emissions, which would assist IPL in complying with future mercury emission regulations. She stated the main benefit would be a reduction in SO_2 emissions, which would decrease IPL's reliance on the current SO_2 market for compliance with the CAIR and improve air quality within the region. Ms. Armstrong stated that the OUCC recommends that IPL receive approval for the increased cost of the Petersburg 4 FGD project.

The OUCC offered three suggestions to improve the future flow of cost information among IPL, the OUCC and the Commission.

First, it was suggested that IPL should notify the OUCC and the Commission of any potential significant cost increases for a particular project if such information is known before a future filing. On rebuttal, Mr. Cutshaw stated that IPL is willing to informally communicate such information, whenever possible. However, he noted the limitations regarding ex-parte communication to the Commission should the information become available less than 30 days prior to an ECR filing. If such a circumstance were to exist, he testified that IPL would notify the OUCC and rely on its case-in-chief to communicate the increase to the Commission.

Second, Ms. Armstrong recommended that IPL file construction progress reports on the Petersburg Unit 4 FGD Enhancement project provided to IPL by its project contractor, similar to the Advatech reports filed for the Harding St. Unit 7 FGD. On rebuttal, Mr. Cutshaw stated that IPL is willing to submit similar reports on the Petersburg 4 FGD Enhancement project. However, since IPL is not using a single Engineering Procurement & Construction contractor for this project (as with the Harding St. Unit 7 FGD project), IPL will not be receiving a single consolidated monthly progress report (as from Advatech). For the Petersburg 4 FGD Enhancement Project, IPL utilized Black & Veatch for the engineering and procurement portions, but is self managing the construction phase of this project and will have a Project Manager managing the construction effort of multiple contractors. Mr. Cutshaw stated that IPL would like the opportunity to meet with the OUCC to determine exactly what information they recommend and to develop a customized report.

Third, Ms. Armstrong recommended that IPL obtain at least two project estimates from two separate vendors for any pollution control projects that IPL wishes to receive Commission approval to construct in future CPCN filings before the Commission. On rebuttal, Mr. Cutshaw stated that IPL is willing to provide additional estimates from separate vendors in future CPCN requests. He noted that an engineering project estimate is not equivalent to detailed engineering design and may cost more than two hundred thousand dollars, which is includable in IPL's preconstruction costs.

In its responses to the Commission's Docket Entry dated February 8, 2010, IPL (1) stated that with regard to the Gypsum Storage Building change, the estimated savings associated with gypsum sales versus gypsum disposal is $5-6/ton which would result in expected lower gypsum disposal costs of $1.0-1.2 million per year. The additional labor costs for a second shift operation will also be saved; this is estimated at $200,000 per year. Thus, the estimated annual total savings associated with the gypsum storage building project is $1.2-1.4 million which justifies the added project cost. The annual revenue requirement for expansion of the gypsum storage building is approximately $0.6 million; (2) stated that with regard to the Engineering & Procurement Costs, these costs are estimated costs for detailed engineering /design work, project management and procurement services provided by the project engineering and procurement contractor (Black & Veatch) that are above those included in the original project estimate. The design changes and upgrades outlined in Mr. Kehres' testimony have significantly increased the engineering and procurement man-hours required for the contractor to complete this project. The engineering and procurement man-hour estimate has increased from approximately 64,000 to 112,000. The additional engineering and project management costs are estimated to be $6.9 million while the procurement services account for approximately $2.0 million; and (3) provided a table comparing the costs as authorized in Cause No. 43403 and the revised estimated costs as proposed in this cause. The revised estimated costs listed in the table as well as those listed in Mr. Kehres' testimony were developed by IPL using the latest cost estimate information available from Black & Veatch, IPL's Engineering & Procurement contractor on the project. IPL has now completed a portion of detailed engineering that gives it a more accurate picture of exactly what type of work will be necessary. This revised cost estimate incorporates the latest bill of quantities for commodity materials as well as cost information from the majority of the major equipment procurements. Construction costs have been estimated based upon the latest quantities available as most of the construction contracts will not be issued until later this year.

The Commission finds that the public convenience and necessity will be served by the construction, implementation and use of Petitioner's CCT projects. Therefore, IPL should be granted a modification of its Certificate of Public Convenience and Necessity for the construction cost estimates of the CCT projects as set forth in Petitioner's Exhibit DK-2. We also modifiy IPL's CPCN to the extent necessary to include the capital maintenance items referenced in Petitioner's Exhibit CF-2 NOx and CF-2 MPP.

Finally, the Commission appreciates the parties' willingness to work together on improving the quality of the information provided through the ongoing ECR review process, but given the expedited nature of the ECR proceedings, it is unclear to what extent the IPL responses to the OUCC recommendations are well-received. IPL and the OUCC shall provide in ECR 15 an update concerning the recommendations of Ms. Armstrong as addressed by Mr. Cutshaw.

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

1. The CCT Projects construction work and construction costs incurred as of November 30, 2009, are hereby approved.

2. Petitioner's proposed rate adjustments in its ECCRA as set out in this Order shall be and the same are hereby approved.

3. Pursuant to 170 IAC 4-6-21, Petitioner shall add the approved return on its QPCP to its net operating income authorized by the Commission for the purposes of IC 8-1-2-42(d)(2) and IC 8-1-2-42(d)(3) in all subsequent Fuel Adjustment Charge proceedings. However, for purposes of computing the authorized net operating income for IC 8-1-2-42(d) and IC 8-1-2-42(d)(3), the jurisdictional portion of the increased return shall be phased-in over the appropriate period of time that the Petitioner's net operating income is affected by this earnings modification resulting from the Commission's approval of this QPCP Construction Cost Rider.

4. Prior to placing the proposed rate adjustments in effect, Petitioner shall file with the Electricity Division of the Commission an amendment to its tariff reflecting the approved QPCP Construction Cost Rider rate adjustments contained in Petitioner's Exhibit CF-3, as shown in Petitioner's Exhibit A.

5. IPL shall be granted a modification of its Certificate of Public Convenience and Necessity for the construction cost estimates of the CCT projects as set forth in Petitioner's Exhibit DK-2 and the addition of capital maintenance items referenced in Petitioner's Exhibit CF-2 NOx and CF-2 MPP.

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

ATTERHOLT, GOLC, LANDIS AND ZIEGNER CONCUR; HARDY ABSENT:

APPROVED: FEB 24 2010

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

Brenda A. Howe

Brenda A. Howe,
Secretary to the Commission