BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130009-EI
FLORIDA POWER & LIGHT COMPANY

MARCH 1, 2013

IN RE: NUCLEAR POWER PLANT COST RECOVERY
FOR THE YEAR ENDING
DECEMBER 2012

TESTIMONY & EXHIBITS OF:

TERRY O. JONES

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF TERRY O. JONES

DOCKET NO. 130009-EI

MARCH 1, 2013

Q. Please state your name and business address.

A. My name is Terry O. Jones, and my business address is 700 Universe Boulevard, Juno Beach, FL 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company (FPL) as Vice President, Nuclear Power Uprate.

Q. Please describe your duties and responsibilities in that position.

A. In my current role, I report directly to the Chief Nuclear Officer. I am responsible for the management and execution of the Extended Power Uprate ("EPU" or "Uprate") Project.

Q. Please describe your educational background and professional experience.

A. I was appointed Vice President, Nuclear Power Uprate on August 1, 2009. In my current position I provide executive leadership, governance, and oversight to ensure the safe and reliable implementation of the EPU Project for the four FPL nuclear units.

I joined FPL in 1987 in the Nuclear Operations Department at Turkey Point. Since then, my positions at FPL have included Vice President, Operations, Midwest Region; Vice President, Nuclear Plant Support; Vice President, Special Projects; Vice President, Turkey Point Nuclear Power Plant; Plant General Manager; Maintenance Manager; Operations Manager and Operations Supervisor. Prior to my employment at FPL, I worked for the Tennessee Valley Authority at the Browns Ferry Nuclear Plant and served in the US Nuclear Navy. I hold a Bachelors of Science degree and an MBA from the University of Miami.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain the EPU project, key management decisions and project activities, and costs incurred in 2012. I also describe the procedures, processes, and controls that ensure FPL's EPU expenditures are reasonable and the result of prudent decision making, and the careful engineering based process employed by FPL to ensure that it is including in its Nuclear Cost Recovery request only nuclear Uprate costs that are "separate and apart" from other costs, such as those for base rate nuclear operations and maintenance or capital projects that are unrelated to the nuclear Uprate project.

Q. Please summarize your testimony.

A. FPL is successfully completing the EPU project that was approved in 2007 to meet customer needs for additional generation in the 2012-2013 timeframe. FPL was commissioned to deliver 399 MWe (net of co-owners' shares) by the end of the project, and it has already met that goal. In fact, approximately 400 MWe of the more than 500 MWe that FPL expects the project to provide is already serving customers. The uprate work at St. Lucie Units 1 and 2 and at Turkey Point Unit 3, which work FPL completed in 2012, resulted in 34% more power than FPL initially projected those units would deliver in its need filing, and as of year end 2012, was saving customers approximately $90 million in fuel costs on an annualized basis. And the work at the fourth and final unit, Turkey Point Unit 4, was nearing completion. This enormous effort required the employment of thousands of workers. In 2012, an average of 3,500 personnel were employed to work on the EPU project every day, and at its peak in 2012, 4,000 additional workers were employed by the EPU project. In total, the 2012 EPU work required over 12 million man hours of effort – over half of the approximately 22.4 million man hours estimated for the entire EPU Project.

To put the total amount of human effort committed to FPL's Florida EPU project into perspective, the project's 22.4 million man hours of effort is about the same amount of labor as was recently employed to construct Dubai's Khalifa Tower, which at 2,722 feet is the tallest building in the world and took about six years and 22 million man hours to construct. What should also not be lost is that the EPU project is far more complex than even such a major building project, since the EPU project's construction work was all performed on and at operating nuclear power plants.

The additional nuclear generation from the EPU project is providing significant and quantifiable benefits for customers without expanding the footprint of FPL's existing nuclear power plant sites and without burning natural gas or foreign oil or emitting greenhouse gasses. FPL's investment in Florida's energy infrastructure and economy has been made possible by the legislature's policy to support investment in nuclear projects, set forth in the Nuclear Cost Recovery (NCR) statute, and the Commission's careful implementation of that policy through the NCR Rule – all of which permits recovery of only a small fraction of FPL's investment that is prudently incurred (*i.e.*, only carrying costs, recoverable O&M, and partial-year in service revenue requirements) through FPL's Capacity Cost Recovery clause. The vast majority – FPL's capital investment – is recovered over the lives of the uprated units, as they are producing power for customers. TOJ-2 depicts, as of December 31, 2012, the FPL investment of approximately $2.9 billion as compared to its Capacity Cost Recovery clause recovery of approximately $320 million, as well as the 2012 workforce summary for the project.

FPL successfully managed the most intensive year of EPU project implementation work in 2012, which included the following:

- Implementation and completion of major modifications during the St. Lucie Unit 1 EPU outage and a brief (6-day) License Amendment Request (LAR) outage, completing the uprate of that unit;
- Implementation and completion of major modifications during the Turkey Point Unit 3 EPU outage, completing the uprate of that unit;

- Implementation and completion of major modifications during the St. Lucie Unit 2 EPU outage, completing the uprate of that unit; and
- Initiation and implementation of major modifications during the Turkey Point Unit 4 EPU outage, which is scheduled to be complete in early 2013.

This implementation work required substantial and iterative engineering design and construction planning, as well as continuous forward-looking project management that resulted in adjustments to outage dates and outage durations, revisions to implementation plans, and intensive contractor oversight and management. Additionally, FPL received all required Nuclear Regulatory Commission (NRC) LAR approvals.

FPL prudently incurred approximately $1,429 million of EPU costs during 2012. Challenges were experienced in the planning and execution of major modifications of "first time evolution" at the first unit at each site – St. Lucie Unit 1 and Turkey Point Unit 3. By "first time evolution" I mean that these modifications were of a high complexity and had not been performed before. As a result, engineering and implementation took more people and more time at the first unit at each site. The project team incorporated modification design changes and lessons learned in the planning and execution of the EPU work at the second unit at each site – St. Lucie Unit 2 and Turkey Point Unit 4. Ultimately, all of the work scheduled to occur in 2012 was performed and resulted in accomplishment of the project MWe goal, while completion of Turkey Point Unit 4 in 2013 will push the output even higher to a project total of over 500 MWe.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring or co-sponsoring the following exhibits which are incorporated herein by reference:

- Exhibit TOJ-1, T-Schedules, 2012 EPU Construction Costs, containing schedules T-1 through T-7B. Exhibit TOJ-1 contains a table of contents listing the schedules that are sponsored and co-sponsored by FPL Witness Powers and myself.
- Exhibit TOJ-2, EPU Workforce Investment and Cost Recovery Summary
- Exhibit TOJ-3, St. Lucie and Turkey Point Plant Photographs
- Exhibit TOJ-4, Illustration of Modifications by Unit
- Exhibit TOJ-5, EPU Project Electrical Output Status
- Exhibit TOJ-6, EPU Project Schedule Overview as of December 31, 2012
- Exhibit TOJ-7, 2012 EPU Cost Variance Drivers
- Exhibit TOJ-8, EPU Work Activities List as of December 31, 2012
- Exhibit TOJ-9, EPU Equipment Placed In Service in 2012
- Exhibit TOJ-10, EPU Project Instructions (EPPI) Index as of December 31, 2012
- Exhibit TOJ-11, EPU Project Reports 2012
- Exhibit TOJ-12, Summary of 2012 EPU Construction Costs

Q. Please describe how the remainder of your testimony is organized.

A. My testimony includes the following sections:

1. Project Summary
2. 2012 Project Activities and Results

3. Project Management Internal Controls
4. Procurement Processes and Controls
5. Internal/External Audits and Reviews
6. "Separate and Apart" Considerations
7. 2012 Construction Costs

PROJECT SUMMARY

Q. What is the EPU Project?

A. The EPU project is increasing FPL's nuclear generating capacity from its four existing nuclear units by fitting the units with higher capacity and more efficient turbines and other necessary equipment to accommodate increased steam flow that will result from increased reactor power. This involves the modification or outright replacement of a large number of components and support structures within FPL's operating nuclear power plants. Photographs of examples of some of this EPU work are attached as Exhibit TOJ-3, and an illustration of the component replacements and modifications at each unit are attached as TOJ-4. Each replacement/modification is considered a project in and of itself which is then integrated into the planned implementation work scope. In the case of some major modifications, some permanent plant equipment has to be removed in order to have the necessary access to perform Uprate modifications and then reinstalled as part of the construction process.

Because the project is modifying FPL's operating nuclear plants, it is a much different construction project than constructing a new combined cycle generating unit at a greenfield site or a modernization project in which the existing generating unit is removed from the site before the new generating unit is installed. In addition to being much more technically difficult, FPL has experienced far greater engineering, construction, and cost uncertainties since FPL is performing the EPU project on existing operating nuclear units. FPL has performed almost all of the modifications during the units' pre-planned refueling outages. Performing the uprate work during the refueling outages minimized the amount of time that these low fuel-cost generators were off line.

Q. How are customers benefiting from the EPU project?

A. During 2012, completed outages resulted in an increase of approximately 400 MWe output for FPL's customers. Upon completion in 2013, FPL expects the EPU project to produce in excess of 500 MWe for FPL's customers. Among other benefits, this increase in nuclear power output will: (i) enhance system reliability and integrity by diversifying FPL's fuel mix; (ii) provide energy and baseload capacity to FPL's customers with zero greenhouse gas emissions; (iii) provide significant fuel cost and environmental compliance cost savings; and (iv) due to the increased capacity at the Turkey Point site, will help maintain balance between generation and load in Southeastern Florida.

Q. When did customers begin receiving the additional output from FPL's nuclear units?

A. Customers began benefitting from an additional 31 MWe from St. Lucie Unit 2 in 2011, by virtue of the installation of a more efficient low pressure turbine generator rotor. Most of the additional output from the EPU project, about 369 MWe, was realized as each of three units returned to service in 2012, resulting in approximately 400 MWe being provided by the end of 2012. At the completion of the final Turkey Point Unit 4 outage, the EPU project electrical output will be in excess of 500 MWe. Exhibit TOJ-5, EPU Project Electrical Output Status, demonstrates the timing of the additional output that has been or will be realized.

Q. As of December 31, 2012, what was the overall EPU project schedule?

A. Exhibit TOJ-6, EPU Project Schedule Overview as of December 31, 2012, illustrates at a high level the tens of thousands of integrated activities that have been accomplished during the project and especially during 2012.

Q. Does FPL include industry best practices into the work being performed for the EPU project?

A. Yes. For example, the FPL project team members participate in nuclear industry working groups organized by the Institute of Nuclear Power Operations and the Nuclear Energy Institute and benefit from lessons learned at other plants. This is supplemented with direct engagement with our industry peers through benchmarking trips to other nuclear sites which have performed similar scopes of work to incorporate best practices. These sources help ensure project decisions are supported by the best information currently available. Additionally, the project benefits from the experience of previous unit outages where other project work was performed and lessons learned for future Uprate modification implementation activities.

2012 PROJECT ACTIVITIES

Q. What key activities occurred in 2012 in execution of the EPU project?

A. Key activities that occurred in 2012 included:

- Final responses to NRC Request for Additional Information (RAIs) and NRC approval of all EPU LARs -
    - Turkey Point Units 3 & 4 EPU LAR - approved June 15, 2012,
    - St. Lucie Unit 1 EPU LAR - approved July 9, 2012, and
    - St. Lucie Unit 2 EPU LAR - approved September 24, 2012;
- Extensive modification engineering for the 2012 EPU outages, including completion of approximately 220 plant design modification packages;
- Continued scheduling and planning for implementation of the modifications in proper sequence, including detailed constructability reviews, and forward-looking project management resulting in adjustments to outage dates, durations and project plans;
- The successful completion of four outages: two at St. Lucie Unit 1, one at Turkey Point Unit 3, and one at St. Lucie Unit 2. The second outage at St. Lucie Unit 1 was a short, six-day outage ("LAR outage") where instrumentation changes and procedure updates were needed to support

- the uprate conditions. These outages resulted in an increased electrical output of approximately 400 MWe for FPL's customers;
- The start of the final Turkey Point Unit 4 outage in November of 2012; and
- Continuous intensive management of major vendors, including the EPC vendor Bechtel.

LICENSING

Q. Please describe the license amendment support activities in 2012.

A. The NRC completed its reviews of FPL's EPU LARs in 2012. FPL management and its licensing management regularly met with the NRC management and lead EPU reviewers to ensure all needed responses to NRC RAIs were expeditiously completed and thoroughly explained to NRC reviewers. The NRC review and approval time for each EPU LAR was originally estimated to be approximately 14 months following submittal to the NRC; however, actual review and approval times were significantly longer primarily due to NRC resource constraints and industry events. The St. Lucie Unit 1 EPU LAR took approximately 20 months, the St. Lucie Unit 2 LAR took 19 months, and the Turkey Point EPU LAR took approximately 20 months for the NRC to review and approve.

As a result of the extended review schedule caused primarily by NRC resource constraints and industry events, FPL was required to continue to retain the services of its LAR engineering analysis vendors for a longer duration than anticipated.

The extended review time also increased the fees FPL was required to pay to the NRC.

Q. Did FPL make adjustments to outage modification assignments and outage dates in 2012?

A. Yes. There was substantial NRC schedule uncertainty with respect to the issuance of the EPU LARs. Because FPL was concerned about completing an outage prior to receipt of the necessary EPU LAR, FPL implemented a decision in 2012 to move outage dates out to provide added certainty that the NRC would complete their reviews and approve the EPU LARs prior to a unit being ready to return to service at the uprated power level. This move in outage dates also added time for additional design engineering, which supported more planning, readiness for the outages, and more outage schedule certainty. However, the movement of the outage start dates required FPL to maintain personnel at the units longer, adding to project costs in 2012. The NRC regulatory delays also required FPL to move a few Uprate modifications out of the St. Lucie Unit 1 2012 outage and into the additional, short duration St. Lucie Unit 1 EPU LAR outage, which included instrumentation modifications, along with set point changes and procedure updates to permit operation in the uprate condition.

LONG LEAD PROCUREMENT

Q. Please describe activities related to the Long Lead Procurement phase in 2012.

A. In 2012, FPL essentially completed the Long Lead procurement phase. Most long lead procurement items were received, inspected, and stored or prepared for installation at the St. Lucie and Turkey Point plants. These items included the massive components necessary to generate more electricity at each unit, including steam turbine rotors, generator rotors, moisture separator reheaters, feedwater heaters, and main feedwater pumps. Many of these items are depicted in Exhibit TOJ-3.

ENGINEERING DESIGN MODIFICATION

Q. Please describe the activities related to the Engineering Design Modification phase in 2012.

A. The engineering design modification process is the process by which the detailed modification packages are prepared. Calculations are performed, construction drawings are issued, general installation instructions are provided, and high level testing requirements are identified. "Design Evolution" or "scope growth" in this context refers to the iterative engineering process needed to address issues discovered during engineering design, such as the need for structural upgrades caused by the ultimate weight and dynamic loading of new equipment, or the need to design modifications for other plant systems that are discovered to be impacted by a planned modification. During the EPU engineering efforts, every system in the secondary side of the St. Lucie and Turkey Point plants was impacted, and in some instances multiple times, as a result of required modifications.

Due to design evolution and complexity of construction, modification engineering and work package preparation took longer than anticipated in 2012. Accordingly, FPL directed Bechtel to subcontract some of the engineering design scope, prioritized design and planning work based on implementation schedules to minimize any impacts to outages, developed and began implementing a plan to streamline the number of Bechtel work packages based on lessons learned, and instituted regular Daily Issue Meetings and senior executive oversight meetings to enhance FPL's management and oversight of Bechtel's engineering design work.

IMPLEMENTATION

Q. Please discuss the magnitude of on-line and outage EPU work that was successfully completed or initiated in 2012.

A. Including the engineering design process described above, the EPU work required:

- An augmented staff of approximately 4,000 additional people at its peak;
- Over 58,000 individually planned, scheduled, and monitored activities supporting approximately 10,600 work packages; and
- Over 12 million man hours of work.

It also involved 4,541 large bore pipe welds, 7,846 small bore pipe welds, 33,791 feet of electric wiring conduit, 250,542 feet of electrical cable, and 29,980 electrical terminations.

Q. Please describe the outage preparation work that occured during non-outage periods.

A. In addition to the substantial modification engineering described above that was performed for upcoming outages, extensive construction planning and logistical work is also performed. And just as additional scope was identified during the engineering design modification phase, additional scope was identified during the construction planning and detailed constructability reviews.

In 2012, FPL and its vendors performed walkdowns and developed subcontractor estimates, labor estimates, security plans, commodities, logistics, and the oversight structure needed to support the implementation activities. Often, new construction "scope" was revealed that could not have been known prior to detailed construction planning, and the time and number of personnel needed to plan for and execute the construction activities safely for a particular modification must be increased. This was especially true at Turkey Point. In addition to the need for more workers, the footprint of the plant is very compact, further increasing the complexity to change out equipment and safely perform modifications. More interferences exist, requiring in many cases extensive efforts to remove them and provide access to the equipment. Examples of design, implementation, and constructability complexities faced in 2012 and an explanation of the major drivers of the cost variance in 2012 are provided in Exhibit TOJ-7.

Q. Please describe the St. Lucie Unit 1 EPU implementation outages that were completed in 2012.

A. St. Lucie Unit 1 completed its second EPU outage in April, with the exception of the LAR outage activities. The EPU outage required replacement or modification of all major equipment required for operation in the uprate condition. This work is detailed in Exhibit TOJ-8, EPU Work Activities List as of December 31, 2012. The unit was initially returned to service at the pre-uprate condition power levels. The NRC then approved the St. Lucie Unit 1 EPU LAR July 9, 2012. Because of extensive preparation and planning, FPL successfully executed the brief LAR outage before the end of July to upgrade instrumentation, set-points, logic, and procedures for operation in the uprate condition. Extensive plant testing was conducted following the return to service with the final 100% power uprate condition providing an additional 148 MWe for FPL's customers. Exhibit TOJ-9 details the equipment placed in service in 2012 at each of the units, including St. Lucie Unit 1. Exhibit TOJ-3, pages 1 to 3, includes photographs of the St. Lucie plant, worker parking, and equipment which increased the complexity and logistics of the project, and examples of the large pieces of equipment that are required to support the increased power production. In total, the work for the St. Lucie Unit 1 outages required the following:

- Augmented staff of 1,847 additional people at its peak;
- Approximately 12,000 individually planned, scheduled, and monitored activities supporting 2,782 work packages; and
- Approximately 1,832,000 man hours of work.

Q. Did FPL experience engineering design scope growth and constructability complexities associated with the EPU work on St. Lucie Unit 1?

A. Yes. The majority of the EPU modifications performed during the St. Lucie Unit 1 outage were "first time evolution" major modifications which affected many large pieces of equipment and components, where interferences had to be removed to provide access. During component removal, discovery required more engineering design, scheduling and planning, constructability reviews and ultimately more time than planned to perform the required modifications. Performing these EPU modifications on a licensed plant required added care and safety considerations to ensure nuclear regulatory requirements were satisfied. These factors added to the complexity of performing the modifications which were contributors to a longer duration of the first St. Lucie Unit 1 outage than planned.

Following the implementation of the modifications, in early 2012, a systematic turnover to operations was required to ensure the systems would perform their functions reliably after implementing the EPU modifications. This plant commissioning required engineers, technicians, and craft support to test the various system controls, logic functions, and verify and validate system operability. In the first part of 2012, the commissioning of systems at St. Lucie Unit 1 proved to be more difficult than expected, in large part due to the complexities of so much new equipment and material installed at the site. As a result, engineers and craft personnel were needed to remain at that site longer than planned to ensure appropriate unit startup, contributing to 2012 cost increases. This complexity is described in Exhibit TOJ-7.

Q. Please describe the St. Lucie Unit 2 EPU implementation outage that was completed in 2012.

A. St. Lucie Unit 2 completed its final EPU outage in November. St. Lucie Unit 2 returned to service with the final 100% power uprate condition providing a total increase of 132 MWe for FPL's customers. In total, the work for the St. Lucie Unit 2 outage required the following:

- Augmented staff of 1,561 additional people at its peak;
- Approximately 9,200 individually planned, scheduled, and monitored activities supporting 1,494 work packages; and

- Approximately 1,279,000 man hours of work.

Q. Did FPL experience engineering design scope growth and construction complexities associated with the EPU work on St. Lucie Unit 2?

A. Yes, but not nearly to the extent experienced at St. Lucie Unit 1. FPL was able to utilize the experience gained at St. Lucie Unit 1 to enhance the St. Lucie Unit 2 outage and on-line engineering designs, work packages, and planning and scheduling. FPL and its vendors performed this work to implement lessons learned in advance of the St. Lucie Unit 2 outage, thus requiring more staffing than planned during that pre-outage period. As a result, the St. Lucie Unit 2 EPU implementation outage was completed in less time and at a lower cost than the St. Lucie Unit 1 EPU implementation outage: the St. Lucie Unit 2 EPU outage was completed 25% faster and at an 18% lower cost than the Unit 1 outage.

Q. Please explain some of the lessons learned that improved cost and schedule performance at St. Lucie Unit 2.

A. FPL and Bechtel made significant work package enhancements based on difficulties experienced in the implementation of similar modifications at St. Lucie Unit 1 by incorporating changes into the modification designs. Additionally, FPL and Bechtel improved the "field change process," whereby the need for an engineered solution is discovered in the field and incorporated into the modification designs. The improved, streamlined process reduced the number of reviews and approvals required for field engineering. FPL also created a dedicated Instrumentation & Control (I&C) team to manage trouble shooting activities that are discovered during unit start up, rather than relying on the plant I&C team, for whom work assignments can change daily.

Q. Please describe the Turkey Point Unit 3 EPU implementation outage that was completed in 2012.

A. Turkey Point Unit 3 completed its final EPU outage in September. The unit returned to service with the final 100% power uprate condition providing approximately 116 MWe for FPL's customers. Included in Exhibit TOJ-3, pages 4 to 49, are photographs showing the site and the worker parking, portable and permanent cranes needed to support the project, the minimal lay down areas which increased the complexity and logistics of the project, and examples of the large pieces of equipment and cranes that are required to support the increased power production. In total, the work for the Turkey Point Unit 3 outage required the following:

- Augmented staff of 3,480 additional people at its peak;
- Approximately 19,000 individually planned, scheduled, and monitored activities supporting 2,900 work packages; and
- Approximately 4,458,130 man hours of work.

Q. Did FPL experience engineering design scope growth and construction complexities associated with the EPU work on Turkey Point Unit 3?

A. Yes. As was the case with the St. Lucie Unit 1 outage, the Turkey Point Unit 3 EPU modifications were "first time evolution" major modifications, requiring the removal of interferences, at an operating nuclear power plant with even less space (than St. Lucie) in which to do the work. During component removal, discovery required more engineering design, scheduling and planning, constructability reviews, and ultimately more time than planned to perform the required modifications. FPL also worked to ensure nuclear regulatory requirements, including safety considerations, were satisfied. Two examples of modifications that encountered these types of complexities – the Control Room Emergency Ventilation System (CREVS) and the Control Room Emergency Filtration System (CREFS) modification and the main condenser replacement – are described below.

CREVS/CREFS: The NRC-mandated modifications to the CREVS/CREFS became very complex. This involved the installation of a hurricane-proof, tornado-proof, earthquake-proof, hardened ventilation and filtration system in an area of the plant not originally designed to meet those specifications. The purpose of the CREVS/CREFS, along with the Control Room Boundary and Control Room Envelope is to provide an acceptable environment for control room personnel and equipment such that the reactor can be safely controlled under normal conditions and maintained in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. There were several engineering design evolutions during the constructability and planning portion of the modification. For example, the modification required the replacement and redesign of structural supports associated with the CREVS/CREFS fans and relocation of existing outside air intakes. Relocation of existing air intakes then required additional seismic and missile protection design to meet safety related design requirements. Additionally, special seismic structures and heavy wall piping were used to move air from the units to the control room. But the added seismic piping supports and seismic structures that hold the ventilation fans and dampers and the filtration portion of the systems required additional planning and manpower to implement the modification. The project team had previously estimated that this NRC-required safety modification would require 11,200 man hours of engineering and 72,066 man hours of field implementation. It actually required 15,502 man hours of engineering and 218,173 man hours of field implementation.

Replacement of the Main Condenser: The main condenser is the component that condenses the 6.4 million pound mass per hour steam flow of the turbine. The condenser has approximately 55,000 tubes for cooling that is supplied by roughly 700,000 gallons of water per minute. Replacing the main condenser required far more engineering design hours, implementation time, implementation manpower, and raw materials than FPL estimated, as a result of location congestion and conditions that could not be discovered until the implementation of the modification began.

Initially, FPL planned to use portable cranes to move the old condenser out and the new condenser into place. However, it was later determined that there was simply not enough land to stage a portable crane of sufficient capacity or maneuver the crane's loads. Accordingly, a specialty track crane was designed. This required the installation of micro piles for one rail, and the use of one of the turbine building crane rails for the other. The scheduling of crane use was critical to ensuring worker safety, as both the turbine building crane and the condenser crane could not be used at the same time.

Additionally, the foundation of the condenser could not be assessed until the old condenser was removed. Upon removal, it was determined that it was necessary to upgrade the foundation steel and concrete for the new condenser, which required additional time for engineering design, planning, and scheduling, as well as additional commodities. The discovery of the need to upgrade spargers that distribute steam as it enters the condenser also required more engineering design, materials, planning, and implementation, all of which added to the complexity of the condenser work. The estimated engineering and field implementation was 215,900 man hours. The condenser replacement including the temporary specialty crane took a total of approximately 368,090 man hours of engineering and field implementation. Additional examples of complexity at Turkey Point Unit 3 are included in Exhibit TOJ-7.

Q. Please describe the final EPU implementation outage, at Turkey Point Unit 4, which FPL began at the end of 2012.

A. The Turkey Point Unit 4 final EPU outage began in November 2012 and is scheduled to complete in the first quarter of 2013. Turkey Point Unit 4 will return to service with the final 100% power uprate condition providing approximately 116 MWe for FPL's customers. Through the end of 2012, the work for the Turkey Point Unit 4 outage had required the following:

- Augmented staff of 3,984 additional people at its 2012 peak;

- Approximately 15,010 individually planned, scheduled, and monitored activities supporting 3,400 work packages; and
- Approximately 1,710,000 man hours of work as of December 31, 2012 (out of an expected more than 2,000,000 man hours).

Q. Did FPL experience engineering design scope growth and construction complexities associated with the EPU work on Turkey Point Unit 4 in 2012?

A. Yes. However, not nearly to the extent experienced at Unit 3. FPL utilized the experience gained at Turkey Point Unit 3 to enhance the Turkey Point Unit 4 outage engineering designs, work packages, and planning and scheduling. This work was performed in advance of the Turkey Point Unit 4 outage, thus requiring more staffing than planned during that pre-outage period. As of December 31, 2012, 56 days into the ongoing Turkey Point Unit 4 outage, the forecast duration of the Unit 4 outage was 33% better than the Turkey Point Unit 3 outage, and the forecast cost was 20% better than the cost of the Unit 3 outage.

Q. Please explain some of the lessons learned that improved cost and schedule performance at Turkey Point Unit 4.

A. FPL incorporated design changes discovered to be needed during the Unit 3 implementation into the modification designs and work packages for Unit 4. Additionally, FPL assigned a logistics manager to consolidate facilities and warehouses used to handle the large quantities of materials housed on site for the project, reduce support staff, and reorganize the manner in which the EPU materials are laid out based on lessons learned at Unit 3. Finally, FPL decided to redistribute a portion of the EPC work scope among four major vendors, as described in more detail below.

Q. Did FPL begin performing EPU project close out activities in 2012?

A. Yes. Some of the activities included in the project closeout are engineering change package closeout, final safety analysis and design basis document updates, closeout of EPU work packages, evaluation of preventive maintenance requirements for new and modified components and development of preventive maintenance work orders, procedure revisions, identification and purchase of spare parts, completion and testing of the control room simulator changes, closeout related purchase orders and contracts, demobilization, and restoration of site facilities and asset recovery.

Q. Please describe FPL's efforts to manage vendor costs in 2012.

A. FPL diligently managed its major vendors, including Bechtel, its EPC vendor, to ensure the costs expended for the assigned scopes of work were reasonable and appropriate. For example, FPL conducted senior-level management meetings in Frederick, Maryland at Bechtel's headquarters to address then-current trends and metrics. FPL also required that its vendors provide detailed schedules and detailed metrics for productivity and commodities, and diligently monitored compliance with those metrics. Feedback was provided through daily focus meetings during outages with major contractors to evaluate earned value and cost performance, daily work plans, and any impacts to schedule and cost. Additionally, FPL held project integration meetings with major contractors generally weekly to discuss schedule compliance of work activities, organization and management issues, and safety issues. FPL leveraged performance in each of these areas to negotiate concessions from Bechtel and other major vendors, resulting in a total reduction in EPU costs in 2012 of $63 million.

At St. Lucie, FPL awarded certain scopes of EPC work to Shaw, which is an experienced nuclear industry construction and engineering firm that has a proven track record on FPL projects. At Turkey Point, given the complexity and magnitude of the work scope and lessons learned from the Turkey Point Unit 3 outage, FPL considered and analyzed a redistribution of a portion of the EPC work scope for the Turkey Point Unit 4 outage. The effort included soliciting competitive bids for the Unit 4 spent fuel pool cooling work and for specific turbine building piping and instrumentation, reviewing technical and commercial terms, negotiating cost and schedule details of work scopes inside the Unit 4 reactor containment building, and comparing commercial proposals with the associated Unit 3 actual costs. As a result, the project execution plan for the Unit 4 EPU outage was restructured and work scope was redistributed among four vendors, including the original EPC contractor. This change allowed the EPC contractor to focus on execution of the remaining EPU Modifications while specialty contractors focused on specific scopes of work in a specific region of the plant. Bechtel retained the EPC implementation scope on the secondary side of the plant, while Shaw's scope within the radiological control area was expanded. Weldtech's scope was expanded during the Unit 3 outage, and it was expanded further for Unit 4. Additionally, PCI – a vendor with a proven track record on FPL radiological scopes of work – was hired to perform a limited scope of work within the Unit 4 radiological control area. These work assignments were made as part of FPL's continuing efforts to control costs and ensure the successful completion of the fourth and final EPU outage.

PROJECT MANAGEMENT INTERNAL CONTROLS

Q. How was the vast amount of project planning, execution, and contractor oversight described above managed by FPL?

A. FPL had robust project planning, management, and execution processes in place. These efforts were spearheaded by personnel with significant experience in project management within the nuclear industry. Additionally, the EPU project used guidelines and Project Instructions to assist project personnel in the performance of their assigned duties. Exhibit TOJ-10, EPU Project Instructions (EPPI) Index as of December 31, 2012, is provided to illustrate the types of instructions that were used.

Q. Please describe the EPU project management organization during 2012.

A. FPL had a dedicated Nuclear Power Uprate team within the nuclear fleet that was responsible for monitoring and managing the Uprate Project, schedule, and costs. In addition to centralized project oversight, there was an EPU Site Implementation Owner, EPU Site Director, and an EPU organization at each site responsible for the efficient and effective engineering and implementation of the EPU project modifications. This decentralized management structure was appropriate as the EPU Project carried out the implementation phase at each of the sites to better integrate EPU activities with plant operating and outage activities. Each site organization's manpower size was adjusted as the execution, power ascension testing, and turnover to operations completed and project close out began.

There was also a separate Nuclear Business Operations (NBO) group that provided accounting and regulatory oversight for the EPU Project. This organization is independent of the EPU Project team and reports to the Vice President Nuclear Finance.

Q. Please describe the role of the NBO group in more detail.

A. As described in project instruction EPPI-150, EPU Project – Nuclear Business Ops Interface, NBO provided accounting and regulatory oversight for the EPU Project. It was independent of the EPU Project team and reported to the Vice President Nuclear Finance. NBO's primary responsibilities included:

- Review, approval, and recording of monthly accruals prepared by the Site Cost Engineers;
- Conducting monthly detail transaction reviews to ensure that labor costs recorded to the EPU Project are only for those FPL personnel authorized to charge time to the EPU Project;
- Conducting on-going analysis to evaluate project costs to ensure they are "separate and apart";
- Creating monthly variance reports that include cost figures used in the EPU Monthly Operating Performance Report;

- Performing analyses of the costs being incurred by the project to ensure that those costs are appropriately allocated to the correct Internal Order established for each nuclear unit's outages;
- Assisting in the classification of Property Retirement Units;
- Setting up and maintaining the EPU Project account coding structure;
- Providing accounting guidance and training to the EPU Team;
- Working closely with FPL's various corporate accounting departments to determine which costs related to the EPU Project are capital and which are O&M;
- Managing internal and external financial audit requests and ensuring that findings and recommendations are dispositioned, as appropriate; and
- Providing oversight and guidance to the EPU Project Team in developing and maintaining accounting-related project instructions to ensure compliance with corporate policies and procedures, and Sarbanes Oxley processes.

Q. What other schedule and cost monitoring controls were in place during 2012?

A. FPL utilized a variety of mutually reinforcing schedule and cost controls and drew upon the expertise provided by employees within the project team, employees within the separate NBO group, and senior nuclear management. Within the organization of the Vice President, Nuclear Power Uprate existed a Controls Group. The Controls Director provided functional leadership, governance, and oversight. Each site had a dedicated EPU Project Controls group lead by a Project Controls Supervisor. The site Project Controls group provided cost and schedule analysis and associated performance indicators on a routine and forward-looking basis thus allowing Project Management to make informed decisions. Exhibit TOJ-11, EPU Project Reports 2012, lists many of the reports that were a direct result of the information the Controls group provided, analyzed and produced.

FPL's efforts to meet the desired completion date of each uprate was tracked through the use of Primavera P-6 scheduling software, enabling FPL to track the schedule daily and update the schedule weekly. This allowed Project Management to monitor and report schedule status on a periodic basis. Updates to the schedule and scope of the project were made as such changes were approved by management. FPL's use of this scheduling software system allowed management to examine the project status at any time as well as request the development and generation of specialized reports to facilitate informed decision making. When FPL identified a scheduled milestone date that may have a high probability of being missed, a mitigation plan was prepared, reviewed, approved, and implemented with increased management attention to restore the scheduled milestone date or mitigate any impact of missing the scheduled date.

As part of the site Project Controls group, there were several highly experienced Cost Engineers assigned to monitor, analyze, and report project costs associated with the Uprate Project. Governed by well established procedures and work instructions, the Cost Engineer received contractor invoices and forwarded them to technical representatives to ensure the scope of work had been completed and the deliverables had been accepted. For fixed-price contracts, the Cost Engineer matched the invoice amount to the contract amount and the deliverable work received from the subject matter expert, which was then sent to the appropriate personnel for approval and payment. The Cost Engineer also prepared accruals and reviewed variance reports monthly for each of the sites, to monitor and document expenditures and commitments to the approved budget. The Project Controls group operated in a transparent manner and its accountability was clear in providing sound analysis based on all available cost and schedule information at their disposal.

Q. What periodic reviews were conducted in 2012 to ensure that the project and key decisions were appropriately analyzed, reviewed and approved at the appropriate management levels?

A. Regularly scheduled meetings were held to help effectively manage the Uprate project and communicate the performance of the project in terms of quality, schedule and costs. These included the following:

- Daily meetings to mutually share lessons learned information from each of the projects and to coordinate project activities;
- Weekly project management, project controls, and risk meetings to review the status of the schedules and project costs, and to identify areas needing attention;
- Monthly meetings with the Chief Nuclear Officer; Vice President, Power Uprate; Implementation Owners; and other project leaders to review

project progress and work through any identified risks to schedules or costs;

- Quarterly FPL Executive Steering Committee presentations on the status of the project;
- Routine Project Meetings involving FPL and individual major vendors to discuss project schedules and challenges; and
- Quarterly Project Meetings involving FPL and its major vendors to discuss strategies to help improve management of risk areas.

The EPU Project also produced several reports. Exhibit TOJ-11, EPU Project Reports 2012, is a listing of reports generated by the project during 2012 with a brief description, the periodicity, and the intended audience of each report. Generally, the project reports provided a status of the project, scope changes, schedule and cost adherence/variance, safety, quality, risks, risk mitigation, and a path forward as appropriate. The information provided by these reports assisted in the overall management of the EPU project.

Q. Please describe the risk management process for the EPU project.

A. FPL's risk management process was governed by project instruction EPPI-340, EPU Project Risk Management Program. FPL's risk management process was used to identify and manage potential risks associated with the Uprate. A Project Risk Committee, consisting of site project directors and subject matter experts, reviewed and evaluated initial cost and schedule projections and any potential significant variances. This committee enabled senior managers to critically assess and discuss risks faced by the EPU project from different departmental perspectives. The committee also ensured that actions were taken to mitigate or eliminate identified risks. When an identified risk was evaluated as high, a risk mitigation action plan was prepared, approved, and executed. The high risk item was monitored through this process until it was reduced or eliminated. Additionally, an EPU Project Risk Management report was presented at meetings with senior management, identifying potential risks by site, unit, priority, probability, cost impact, and the unit or persons responsible for mitigating or eliminating the risk. These steps ensured continuous, vigilant identification of and response to potential project risks that could pose an adverse impact on the cost or schedule performance of the project.

Q. Please describe the risk management process as it applied to operational risk.

A. EPU project work was performed during normal plant operations and during planned refueling outages that were adjusted and extended in duration in order to permit uprate work to be performed. The amount of work that could be safely performed during these plant conditions was dependent upon the minimum required systems or components needed to support the plant operating condition. Extreme care in the planning, scheduling, and execution of the work activities was required to ensure the plant was operated in accordance with applicable NRC regulatory and plant technical specification requirements. This required proper sequencing of work activities that could be safely performed during normal plant operations or those that needed to be performed during planned refueling outages, including work activities that could be safely performed in parallel and those that needed to be performed in series. This operational risk management accomplished two major objectives: first was to ensure the equipment was in a state that makes it safe for workers to perform the work, and second was to ensure that the plant systems and components were properly maintained as required for public health and safety. This operational risk management through the careful planning, scheduling, and execution of work activities added to the complexity of the implementation phase of the EPU project.

PROCUREMENT PROCESSES AND CONTROLS

Q. Please describe the contractor selection and contractor management procedures that applied to the EPU project in 2012.

A. The contractor selection procedures that applied to the Uprate project are found in NEE-PRO-1460, Purchasing Goods and Services-Policy and Definitions and its series of procurement procedures and Nuclear Fleet Guideline BO-AA-102-1008, Procurement Control. Additionally, the EPU project had previously developed an EPPI, and as explained in the EPPI procedure, the standard approach for the EPU project in the procurement of materials or services with a value in excess of $25,000 was to use competitive bidding. However, the use of single source, sole source, and Original Equipment Manufacturer providers was also necessary in certain situations. It is logical that the use of single and sole source procurements increased as the project entered the final implementation stages. For example, many of the contracts that were competitively bid and awarded were given work scope additions through the single source procurement process. Typically, it was not in the best business interest of FPL to contract with another vendor when security screening, site specific training, and training in policies, programs, procedures, and work processes were already established for vendors with rates that had previously been determined to be competitive and reasonable. The benefits of this included cost savings in mobilization, security screening, site specific training, site familiarity, and the important aspects of FPL's expectations for a safety conscious work environment. FPL's policies required proper documentation of justifications and senior-level management approval of single or sole source procurements.

FPL maintained its focus on the process of documenting and approving single and sole source procurements, to ensure compliance with BO-AA-102-1008, EPPIs and to facilitate review by third parties who are not directly involved in the nuclear procurement process. The single source justification (SSJ) expectations were included in appropriate project instructions, and all new applicable personnel assigned to the EPU Project were required to review and understand the SSJ expectations.

With respect to vendor management, the EPU Project Directors at each site ensured vendor oversight was provided by the experienced Project Managers, the Site Technical Representative, and Contract Coordinators. Together, these representatives provided management direction and coordinated vendor activity reviews while the vendors were on site. The Contract Coordinators verified the vendor had met all obligations and determined whether any outstanding deliverable issues existed using a Contract Compliance Matrix. In addition to assisting with the development and administration of contracts, Nuclear Sourcing and Integrated Supply Chain groups completed updates as necessary to a Project Contract Log and reported the status of contracts to Project Management. EPU management also held routine meetings with vendors' senior management as previously discussed.

Q. What was FPL's approach to contracting for the EPU project?

A. FPL structured its contracts and purchase orders to include specific scope, deliverables, completion dates, terms of payment, commercial terms and conditions, reports from the vendor, and work quality specifications. Project Management had several types of contracts available depending on how well the scope of work and the risk associated with the work scope could be defined. Fixed price or lump sum contracts were used where project work scope was well-defined and risk was limited. Project Management used time and material contracts where project work scope was not well-defined and where there was greater risk to completing the work scope. These and other contract provisions helped to ensure that the contractors performed the right work at the right time for the right price, which ultimately benefits FPL's customers.

Additionally, as described above, FPL made decisions in 2012 to redistribute EPC scope to obtain greater cost and schedule certainty. This is reflective of the type of careful and strategic vendor management that FPL employed.

INTERNAL/EXTERNAL AUDITS AND REVIEWS

Q. Are FPL's financial controls and management controls audited?

A. Yes. Several audits have been conducted to ensure compliance with applicable project controls.

Q. What external audits or reviews have been conducted to ensure the project controls are adequate and costs are reasonable?

A. FPSC staff is conducting two audits related to 2012 – a financial audit and an internal controls audit. The 2012 FPSC staff financial and internal controls audits will be provided to the Commission when completed.

Additionally, FPL retained Concentric Energy Advisors, Inc. to conduct a review of the 2012 EPU project management controls. The results of this review are presented through the testimony of Mr. John Reed, the Chief Executive Officer of Concentric Energy Advisors. Burns and Roe Enterprises, Inc. (BREI) was also engaged to review the prudence of FPL's management of the EPU project activities in 2012. The results of this review are presented through the testimony of Mr. Albert Ferrer, Vice President of BREI.

Q. Does Internal Audit conduct an annual review to ensure the project controls are adequate and costs are reasonable?

A. Yes. Experis, formerly Jefferson Wells, is performing an audit of 2012 expenses at Internal Audit's direction. Specifically, the Experis audit focuses on ensuring that costs charged to the EPU project are for the EPU project and are recorded in accordance with FPSC Rule 25-6.0423, and includes independent testing of expenses charged to the EPU project for the period January 1, 2012, to December 31, 2012. FPL expects this audit to be completed in the second quarter of 2013, at which time the results will be available to the Commission, Commission staff, and other parties.

"SEPARATE AND APART" CONSIDERATIONS

Q. Would any of the EPU costs included in FPL's filing have been incurred if the FPL nuclear generating units were not being uprated?

A. No. The construction costs, associated carrying charges and recoverable O&M expenses for which FPL is requesting recovery through the NCRC process were caused only by activities necessary for the Uprate project, and would not have otherwise been incurred. I note that, as explained in FPL Witness Powers' testimony and schedules, only carrying costs, recoverable O&M expenses, and partial-year revenue requirements for items placed in service are requested for recovery for the EPU Project, consistent with the Commission's NCRC rule.

Q. Please explain the processes utilized by FPL to ensure that only those costs necessary for the implementation of the Uprate are included for NCRC purposes.

A. Consistent with project instruction EPPI-180, EPU Nuclear Cost Recovery, FPL conducted engineering analyses to identify major components that must be modified or replaced in order to enable the units to function safely and reliably in the uprated condition. However, as inspections, LAR engineering analyses, and design engineering modifications were performed, the need for additional modifications or replacements necessary for the Uprate project was identified. FPL's 2012 EPU activities, and their associated costs, were "separate and apart" as required by the Nuclear Cost Recovery process.

2012 CONSTRUCTION COSTS

Q. What type of costs did FPL incur for the Uprate project in 2012?

A. As indicated in Exhibit TOJ-1, Schedule T-6 and T-4, and summarized on Exhibit TOJ-12, Summary of 2012 EPU Construction Costs, costs were incurred in the following categories: License Application; Engineering and Design; Permitting; Project Management; Power Block Engineering, Procurement, etc.; Non-Power Block Engineering, Procurement, etc.; and Recoverable O&M. These costs were the direct result of the prudent project management, decision making, and actions described previously. Each category reflects some variance against what was estimated earlier in 2012.

Q. Please describe the costs incurred in the License Application category and the variance, if any, from the 2012 actual/estimated costs in this category.

A. Licensing Costs in 2012 consisted primarily of charges for contractor services rendered in supporting preparation, review, and NRC approval of the EPU LARs and fees paid to the NRC for their review. The primary contractors were Westinghouse, Areva, and Shaw Stone & Webster. FPL incurred $50.5 million in this category in 2012, which was $24.5 million more than the actual/estimated amount. This variance was primarily attributable to (i) additional NRC-required engineering analyses and evaluations, such as those due to industry bulletins on accelerated steam generator tube wear, the Westinghouse fuel model, other balance of plant modifications, and setpoint changes; (ii) increased fees paid to the NRC due to its extended review time; (iii) increased vendor costs due to the NRC's extended review time; and (iv) the reclassification of costs for the "umbrella modifications" (the engineering change modification at each unit that implements the NRC approved License Amendment) from the Power Block Engineering, Procurement, etc. category to the License Application category.

Q. Please describe the costs incurred in the Engineering and Design category and the variance, if any, from the actual/estimated costs in this category.

A. Engineering and Design Costs consist primarily of costs for FPL personnel in the FPL engineering organizations at both sites and in the central organization. Some of these personnel provide management, oversight, and review of the LAR activities, while others are oriented towards management, oversight, and review of the detail design activities being performed by the EPC contractor and other contractors. FPL incurred $30.5 million in this category in 2012, which is $5.8 million more than the actual/estimated amount. This was primarily attributable to the need to manage and oversee engineering design scope growth and the EPC and other contractors' engineering and implementation efforts for the St. Lucie and Turkey Point outages.

Q. Please describe the costs incurred in the Permitting category and the variance, if any, from the actual/estimated costs in this category.

A. All permits applicable to the EPU Project were approved in 2011. Accordingly, there were no costs incurred by the EPU Project in the Permitting category in 2012.

Q. Please describe the costs incurred in the Project Management category and the variance, if any, from the actual/estimated costs in this category.

A. Project Management Costs relate to overall project oversight including project and construction management, and project controls and non-NRC regulatory compliance. These oversight activities are performed by personnel located at both sites, by the EPU central organization, and by non-EPU organizations such as NBO, New Nuclear Accounting and Regulatory Affairs. FPL incurred $57.1 million in this category in 2012 which was $4.8 million more than the actual/estimated amount. This was primarily attributable to an increase in FPL project and construction management oversight of the EPC and other vendors caused by scope growth, causing increased engineering design and implementation work, examples of which are provided above in the explanation of the various 2012 outages.

Q. Please describe the costs incurred in the Power Block Engineering, Procurement, etc. category and the variance, if any, from the actual/estimated costs in this category.

A. The majority of the costs in this category reflect payments to the EPC vendor and other vendors for engineering, procurement, and construction resources that supported the successful completion of the EPU outages at St. Lucie Units 1 and 2, Turkey Point Unit 3, and the first two months of the Turkey Point Unit 4 outage; the continued engineering efforts to prepare for the EPU implementation outages; payments to Siemens for turbines and generator rotors; and payments to Thermal Engineering International for feedwater heaters and moisture separator reheaters, main condensers, and increased capacity heat exchangers and pumps and valves required to support the uprate conditions.

FPL incurred $1,252 million in this category in 2012, which is $296.7 million more than the actual/estimated amount. The cost variance is the result of implementing first time evolution modifications, described in more detail above and in my Exhibit TOJ-7, which resulted in more design engineering, more implementation work scope requiring more craft labor and field non-manual support, longer than estimated installation durations which included planning, scheduling, and execution of the modification activities, and more commodities than previously estimated.

Q. Please describe the costs incurred in the Non-Power Block Engineering, Procurement, etc. category and the variance, if any, from the actual/estimated costs in this category.

A. Non-Power Block Engineering Costs consist primarily of costs for facilities for engineering and project staff at site locations and simulator upgrades required to reflect the uprate conditions. FPL incurred $1.7 million in this category in 2012. This represents $0.6 million more than the actual/estimated amount. The variance is primarily attributable to additional work scope that was determined to be necessary to complete the simulator upgrades.

Q. Please describe the costs incurred as EPU Recoverable O&M.

A. Recoverable O&M expenses in 2012 were $7.8 million. This represents a variance of $7.5 million less than the actual/estimated amount. Consistent with FPL's capitalization policy, the commodities that make up these expenditures consist of non-capitalizable computer hardware and software and office furniture and fixtures needed for new project-bound hires, all of which are segregated for EPU Project personnel use only, as well as incremental staff and augmented contract staff. Additionally, modifications that did not meet the capitalization criteria were included in this category along with O&M EPU equipment inspections and obsolete inventory write-offs. The variance is primarily attributable to fewer obsolete inventory write-offs than estimated for 2012.

Q. Please describe the costs incurred in the Transmission category.

A. Transmission Costs were $29.7 million in 2012, which is $2.3 million more than the actual/estimated amount. The expenditures in the Transmission category include plant engineering, line engineering, substation engineering, and line construction. This variance is a result of the installation of the new main transformer at St. Lucie Unit 2 taking longer than estimated. However, FPL was able to obtain cost savings on the bidding and purchase of major substation material and substation construction labor contracts, minimizing the variance in this category.

Q. Were FPL's 2012 EPU expenditures prudently incurred?

A. Yes. FPL incurred costs of approximately $1,429 million in 2012. FPL's actual 2012 costs were greater than its previous estimate for the reasons described above, and are primarily attributable to the human capital necessary to design and implement the required modifications needed to support the EPU; increased engineering analysis vendor costs and NRC costs due to the extended NRC reviews of the license amendment requests; increased work scope for design modification engineering; and increased modification implementation time due to increased work scope and constructability complexities.

All of FPL's expenditures were necessary so that the uprate work could be performed during the planned outages. Through well-qualified, experienced personnel's application of the robust internal schedule and cost controls, careful vendor oversight, and the ability to continuously adjust based on lessons learned and the project's evolving needs, FPL is confident that its 2012 EPU management decisions were well-founded and prudent. All costs incurred in 2012 were the product of such decisions, were prudently incurred, and should be approved.

Q. Does this conclude your direct testimony?

A. Yes.

TOJ – 1

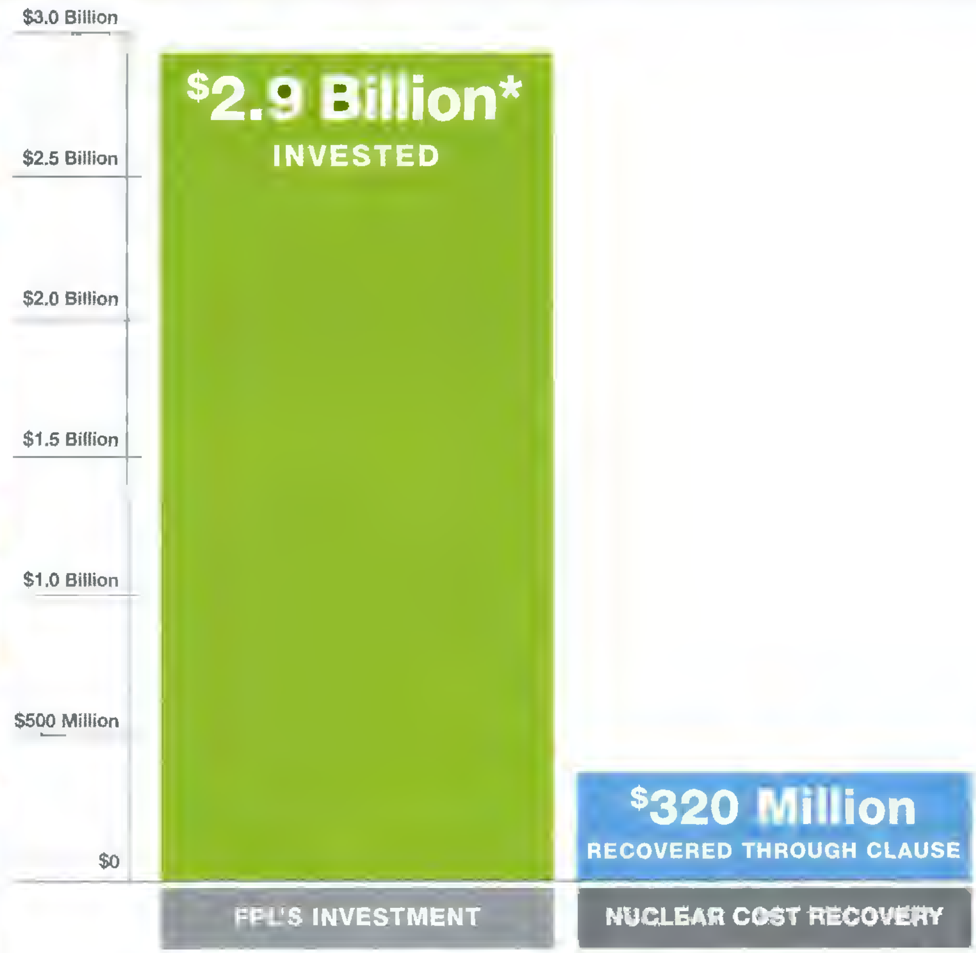
TOJ – 1 is in the Nuclear Filing Requirements Book

TOJ – 2

Docket No. 130009-EI
EPU Workforce Investment Summary
and Cost Recovery Summary
Exhibit TOJ-2, Page 1 of 2

EPU Investment and Cost Recovery Summary Through Dec. 31, 2012

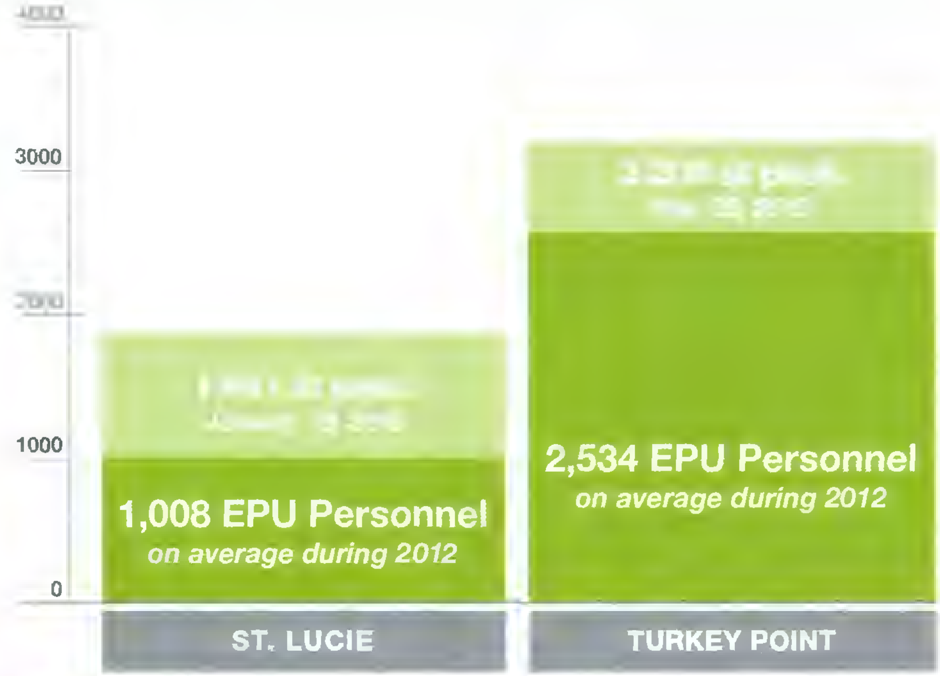
Photo: FPL's St. Lucie Plant, Feb. 2, 2012, during EPU construction
By the end of 2012, approximately 400 new megawatts of nuclear capacity constructed through the EPU project were serving FPL customers.



Figures above represent total amounts since the beginning of the project through Dec. 31, 2012
* Represents FPL's capital investment in the EPU project

EPU Workforce Summary January–December 2012

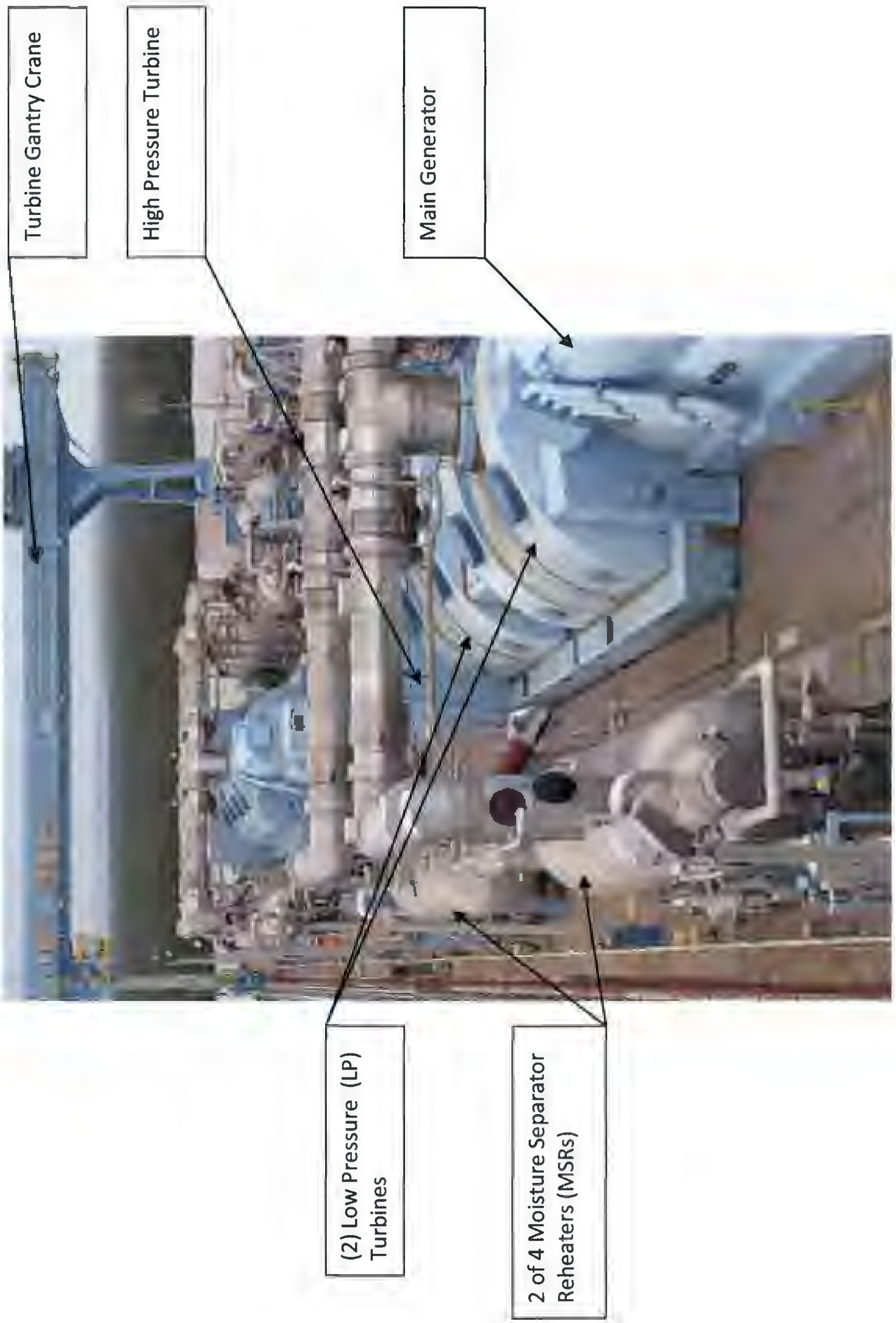
Photo: *FPL's Turkey Point Plant, Feb. 9, 2012, during EPU construction*
Temporary overflow parking accommodates thousands of additional personnel on-site as part of a massive EPU-related workforce.



More than 3,500 workers on average

St. Lucie Site 2012 Unit 1 Outage site lay out and parking for thousands of workers

St. Lucie Unit 1 on left shows the early stage of mobilization of safety barriers in advance of demolition, compared to Unit 2 (on right) which is in operation



This is an operating turbine deck with major components identified

Turkey Point Unit 3 2012 Outage Site Layout with thousands of workers on Site. Note the close proximity of the fossil units 1 and 2 on the left to the nuclear units 3 and 4 and the close proximity of the water result in very little space for new plant components and pre-fabrication areas.

Turkey Point Units 3 and 4 use approximately 1,300,000 gallons per minute of cooling water which enters from the right and exits on the left side to support the generation of over 1,700 MWe which required the replacement of many major components.

Turkey Point Temporary Crane Locations in the Red Circles and the Permanent Turbine Building Gantry Crane in the Green Circle

Turkey Point main turbine deck with major components removed on either side of the blue tarp covering the lower casing of the main turbine. The red circles high light some of the many temporary cranes on site needed to support the work.

Turkey Point main turbine deck with scaffolding and orange safety barriers in place to support the work activities.
→ Denotes temporary environmental structure which was constructed for the main generator rewind.

MOISTURE SEPARATOR REHEATERS MODIFICATION

One of eight Moisture Separator Reheaters being loaded onto the heavy haul transporter to be moved to the plant and onto the turbine deck

MOISTURE SEPARATOR REHEATERS MODIFICATION (Continued)

One of the eight Moisture Separators being moved into position on the main turbine deck

MOISTURE SEPARATOR REHEATERS MODIFICATION (Continued)

Two of the eight new Moisture Separators in their location on the Main Turbine Deck

MOISTURE SEPARATOR REHEATERS MODIFICATION (Continued)

Moisture Separator Drain tank showing welded piping connections to the Moisture Separator Reheater

MOISTURE SEPARATOR REHEATERS MODIFICATION (Continued)

New Moisture Separators in place with scaffolding erected to install the Moisture Separator reheated steam outlets and the inlets to the center of the low pressure turbines. This represents one EPU modification of the approximate total of 220 implemented for the project.

MAIN CONDENSER REPLACEMENT MODIFICATION

Turkey Point Main Condenser. Scaffolding being erected to support the Main Condenser Replacement modification.

MAIN CONDENSER REPLACEMENT MODIFICATION (Continued)

Turkey Point Main Condenser canal cooling water box removal to expose the tens of thousands of condenser tubes for removal.

MAIN CONDENSER REPLACEMENT MODIFICATION (Continued)

Turkey Point main condenser tube sheet plate which holds the cooling water tubes in place. These are removed and the new condenser tube bundles are installed

MAIN CONDENSER REPLACEMENT MODIFICATION (Continued)

Turkey Point main condenser scaffolding erection to support condenser tube removal.

MAIN CONDENSER REPLACEMENT MODIFICATION (Continued)

As part of the condenser upgrades, workers removed legacy tube sheets using acetylene torches to simultaneously cut and remove both sheets from all condenser bays. Like many EPU modifications at Turkey Point, the removal of the tube sheets was a first-time evolution, thus requiring careful planning and execution.

MAIN CONDENSER REPLACEMENT MODIFICATION (Continued)

Turkey Point main condenser area with the old condenser demolished and preparations being made to install the new condenser tube bundle.

MAIN CONDENSER REPLACEMENT MODIFICATION (Continued)

Turkey Point new condenser tube bundle replacement being transported for installation.

MAIN CONDENSER REPLACEMENT MODIFICATION (Continued)

Turkey Point main condenser, the new tube bundle is being lowered by the temporary specialty crane and being guided onto the slide beams.

MAIN CONDENSER REPLACEMENT MODIFICATION (Continued)

Turkey Point main condenser showing the four condenser sections with the new condenser tube bundles installed.

MAIN CONDENSER REPLACEMENT MODIFICATION (Continued)

The condenser blue water boxes complete the condenser tube bundle replacement. The water boxes receive the canal cooling water leaving the more than 55,000 new condenser tubes and directs the cooling water to the discharge piping which returns it to the cooling canal.

FEEDWATER HEATERS MODIFICATION

One of four feedwater heaters per unit is being removed from the blue heavy hauler and being staged for lifting onto the turbine deck.

FEEDWATER HEATERS MODIFICATION (Continued)

One of four feedwater heaters being lifted by the turbine building crane for placement on the turbine deck.

FEEDWATER HEATERS MODIFICATION (Continued)

One of four feedwater heaters lifted from the staging area to the turbine deck.

FEEDWATER HEATERS MODIFICATION (Continued)

One of four feedwater heaters being moved across the equipment crowded turbine deck for placement on the deck.

FEEDWATER HEATERS MODIFICATION (Continued)

One of four feedwater heaters being lowered into the close-quarters of the turbine deck, where it will then be moved to its location.

FEEDWATER HEATERS MODIFICATION (Continued)

One of the four feedwater heaters being lowered onto beams. Rigging will be attached to the feedwater heater to move it into its location.

Turkey Point Main Turbine Deck showing the High Pressure Turbine enclosure, 1 of 4 Moisture Separator Reheaters and 1 of 2 of the 6A (B) High Pressure Feedwater Heaters, before EPU. All of these components were demolished and new larger equipment was installed to produce more power.

New components installed. High Pressure Turbine, Moisture Separator Reheaters, and High Pressure Feedwater Heater

MAIN FEEDWATER PUMPS MODIFICATION

Scaffolding being erected in the congested area around and over one of the Feedwater Pumps

NORMAL CONTAINMENT COOLERS MODIFICATION

This is the Turkey Point Unit 3 primary containment showing the major components, the Reactor Vessel in the center, the 3 Steam Generators, lower left, upper center and right, and the Pressurizer on the left. A very sturdy platform was installed over the reactor cavity to provide lay down and staging area for the Normal Containment Cooler modification.

NORMAL CONTAINMENT COOLERS MODIFICATION (Continued)

Primary Containment with scaffolding being erected to support crane erection and access for workers.

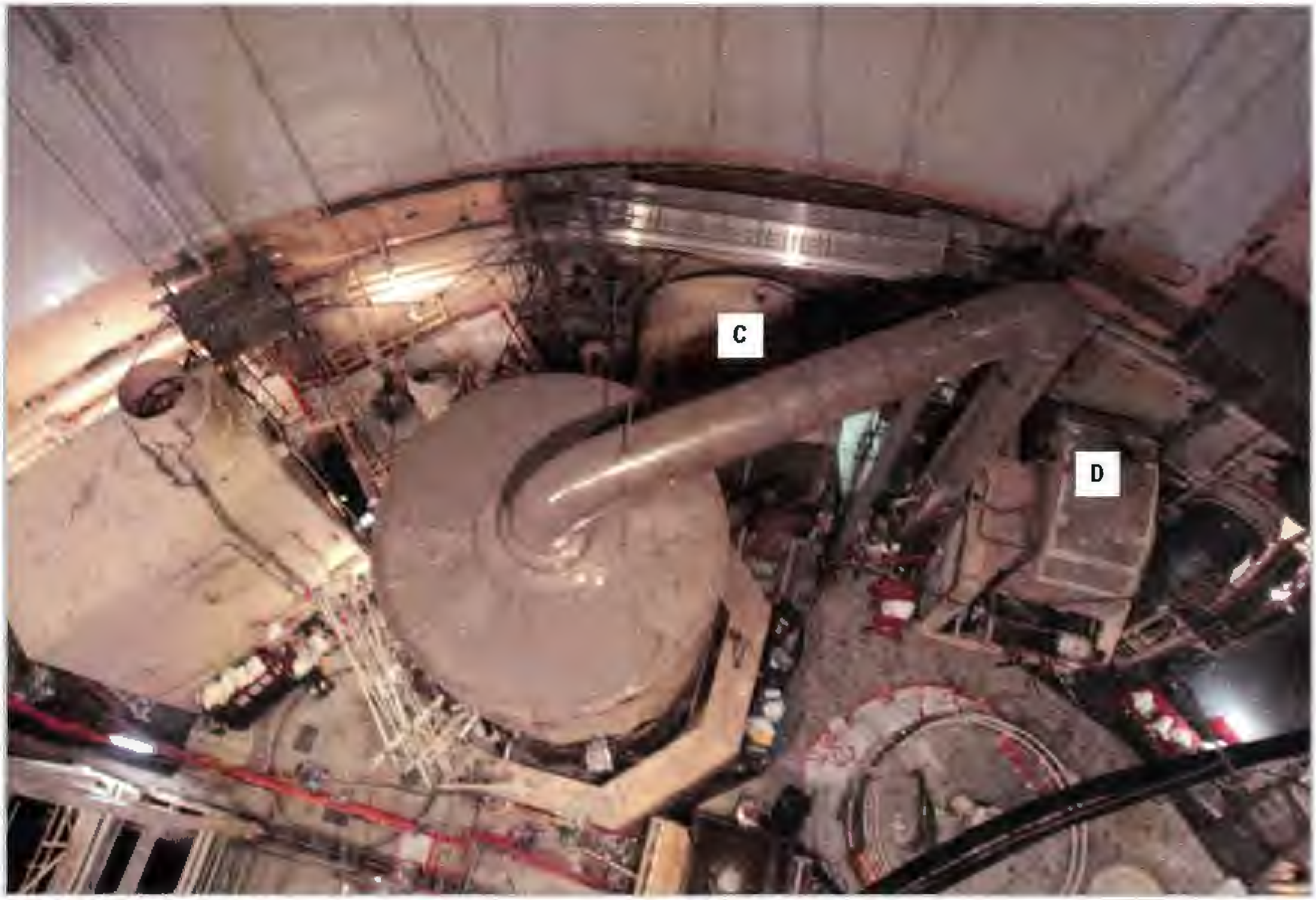
NORMAL CONTAINMENT COOLERS MODIFICATION (Continued)

Installation of the temporary crane which will be used to move components and materials.

NORMAL CONTAINMENT COOLERS MODIFICATION (Continued)

The temporary crane erected in the Primary Containment to support the movement of materials and components.

NORMAL CONTAINMENT COOLERS MODIFICATION (Continued)



The equipment and components located inside the primary containment generate a tremendous amount of additional heat. For that reason all four normal containment coolers (two pictured above) were replaced with newer models in both units. This will increase the cooling capacity inside the reactor buildings.

NORMAL CONTAINMENT COOLERS MODIFICATION (Continued)

Turkey Point Normal Containment Coolers demolition. Workers are in Radioactive Contamination Protective Clothing erecting needed scaffolding.

NORMAL CONTAINMENT COOLERS MODIFICATION (Continued)

Work inside the containment often place workers in tight, hot spaces. A worker in protective clothing is preparing to weld a support in very close quarters for the Normal Containment Cooler replacement.

NORMAL CONTAINMENT COOLERS MODIFICATION (Continued)

Primary Containment. Worker in protective clothing adding structural material in support of the Normal Containment Cooler modification.

NORMAL CONTAINMENT COOLERS MODIFICATION (Continued)

Workers using the new Normal Containment Cooler equipment are practicing installing a cooler outside of the Primary Containment in a clean non-radiological area to reduce assembly time in the Primary Containment radiological control area.

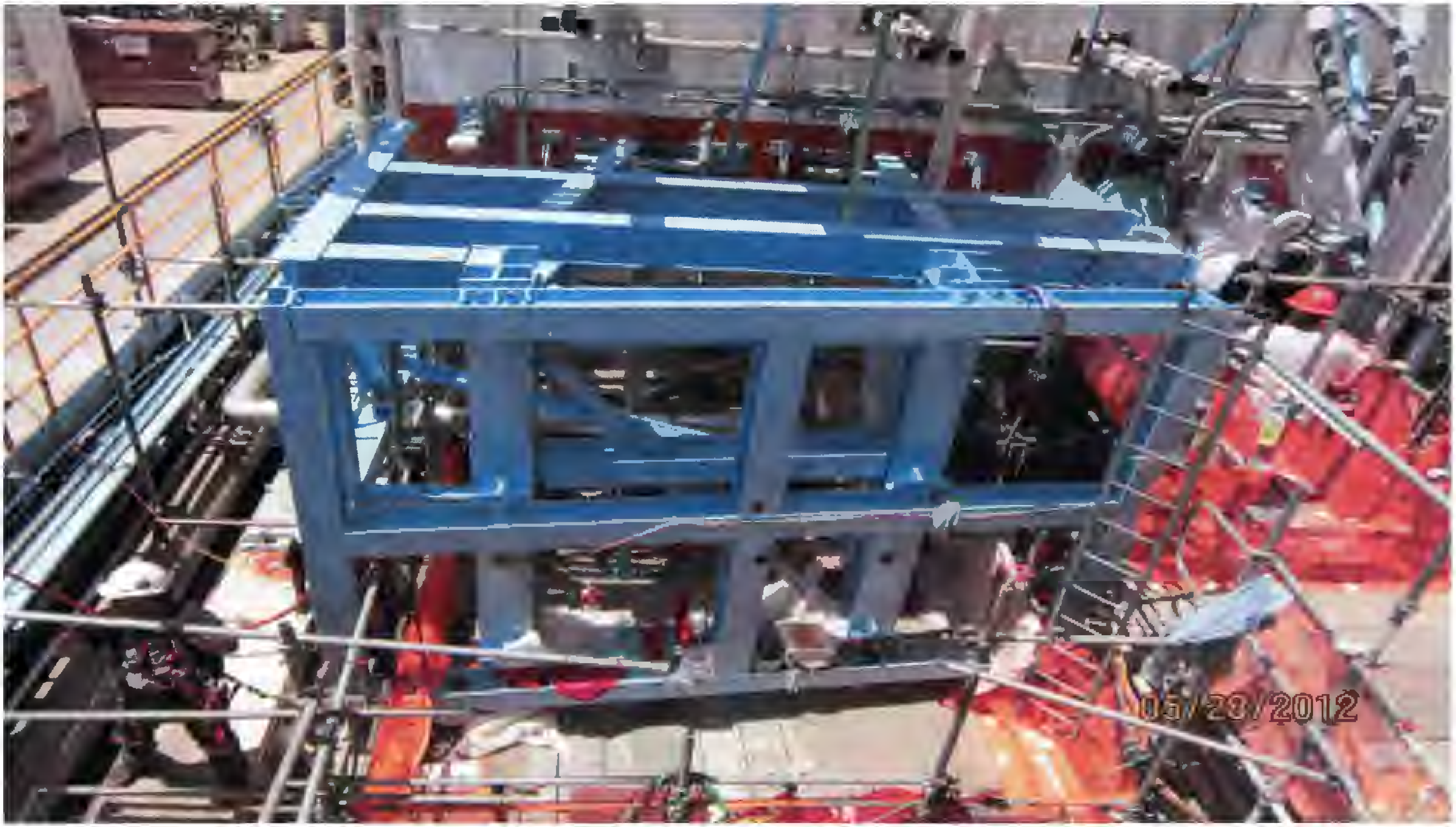
NORMAL CONTAINMENT COOLERS MODIFICATION (Continued)

Primary Containment. One of the Normal Containment Coolers being lowered by crane and guided into place by workers using tag lines.

CONTROL ROOM EMERGENCY VENTILATION AND FILTRATION SYSTEMS MODIFICATION

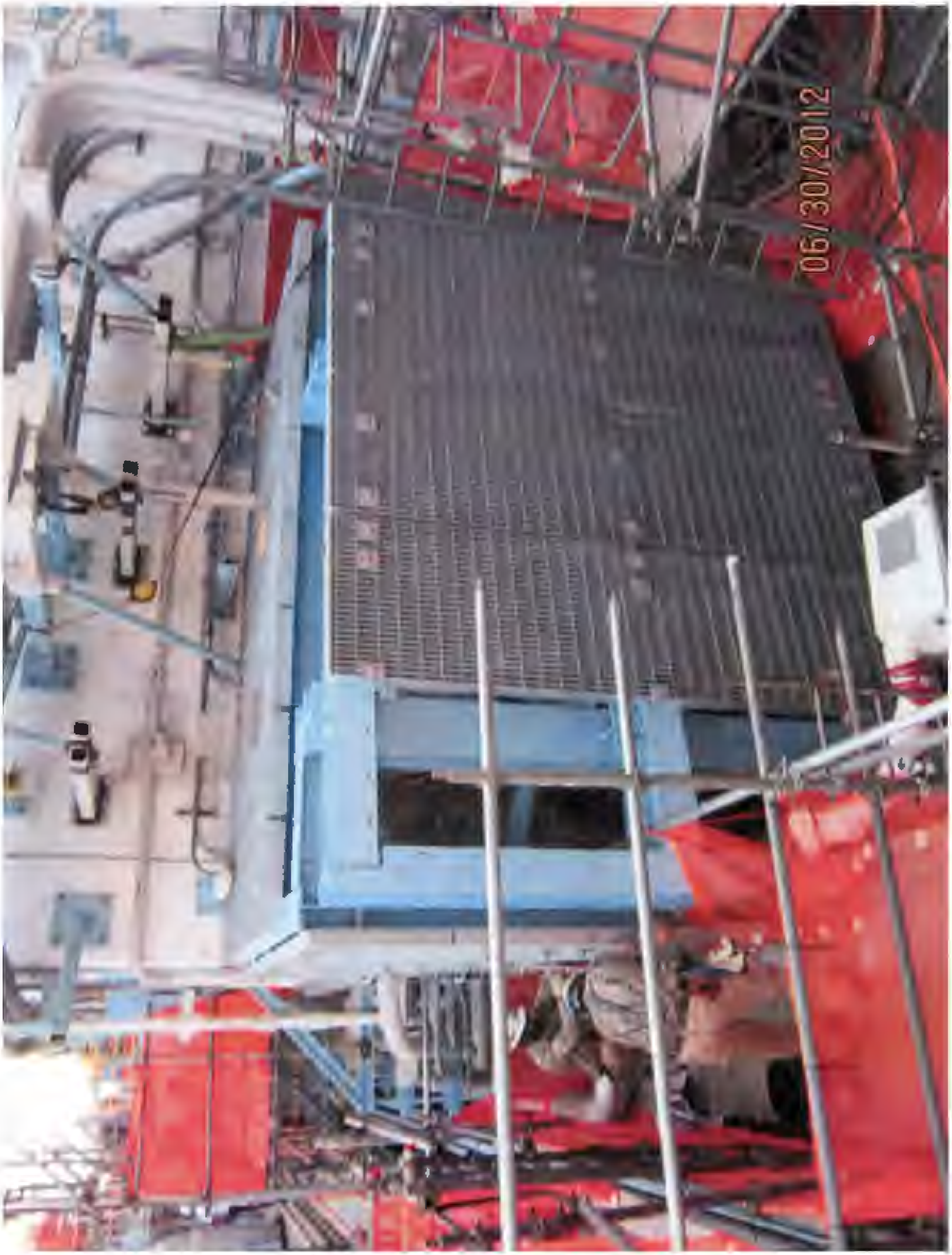
Turkey Point. Scaffolding erected to support the removal of interferences and install the Control Room Emergency Ventilation and Filtration Systems (CREVS/CREFS) with missile protected structures.

CONTROL ROOM EMERGENCY VENTILATION AND FILTRATION SYSTEMS MODIFICATION (Continued)



Turkey Point construction of missile barrier structure for the CREVS/CREFS systems. The blue steel beams are new materials being installed.

CONTROL ROOM EMERGENCY VENTILATION AND FILTRATION SYSTEMS MODIFICATION (Continued)



Turkey Point. Workers complete the installation of the missile barrier structure for the CREVS/CREFS systems.

CONTROL ROOM EMERGENCY VENTILATION AND FILTRATION SYSTEMS MODIFICATION (Continued)

Turkey Point heavy walled ventilation pipe with the many large custom made supports built to design specifications that satisfy regulatory requirements for the CREVS/CREFS systems.

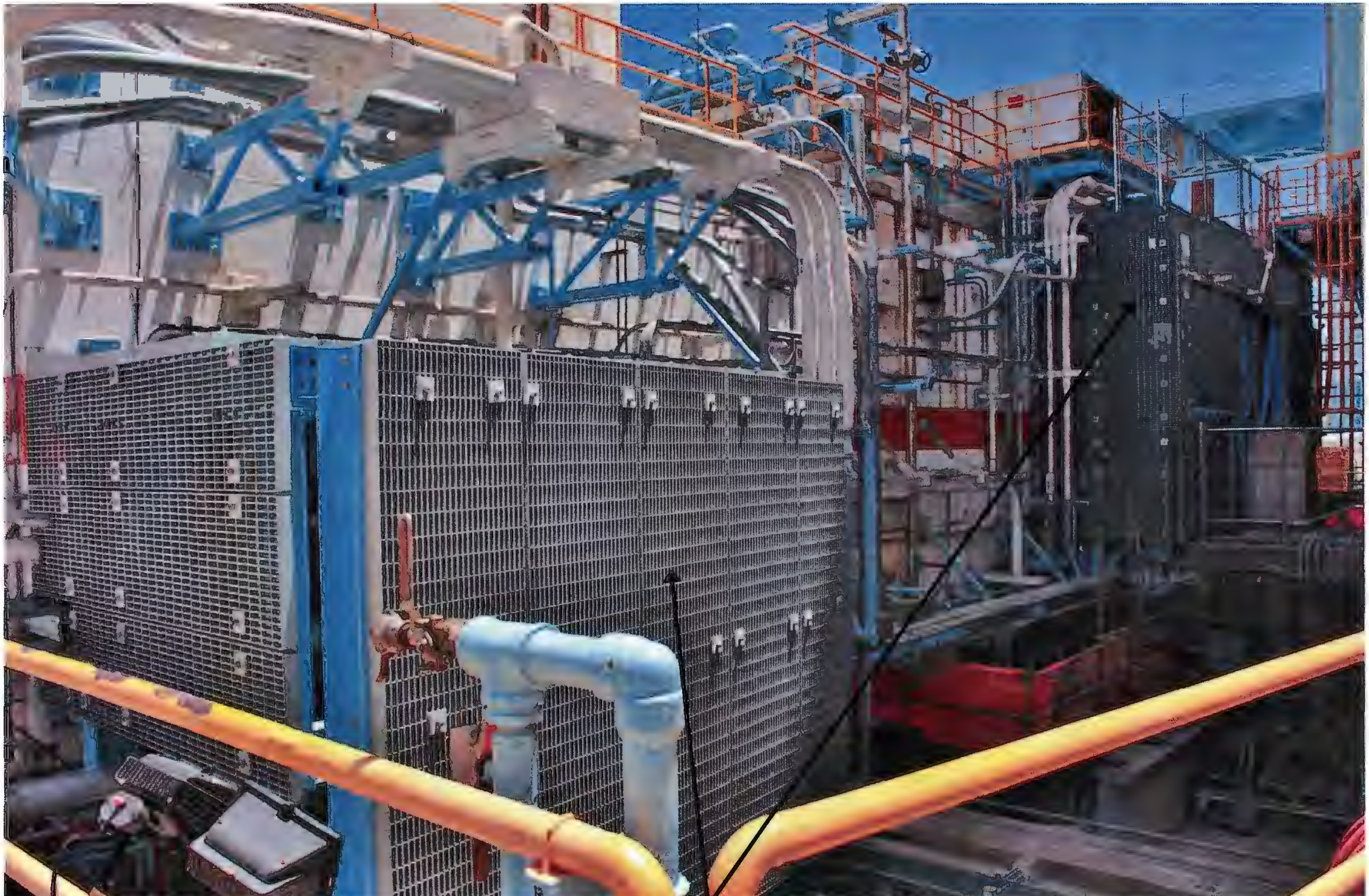
CONTROL ROOM EMERGENCY VENTILATION AND FILTRATION SYSTEMS MODIFICATION (Continued)

Turkey Point heavy walled emergency ventilation pipe with one of its very large structural supports.

CONTROL ROOM EMERGENCY VENTILATION AND FILTRATION SYSTEMS MODIFICATION (Continued)

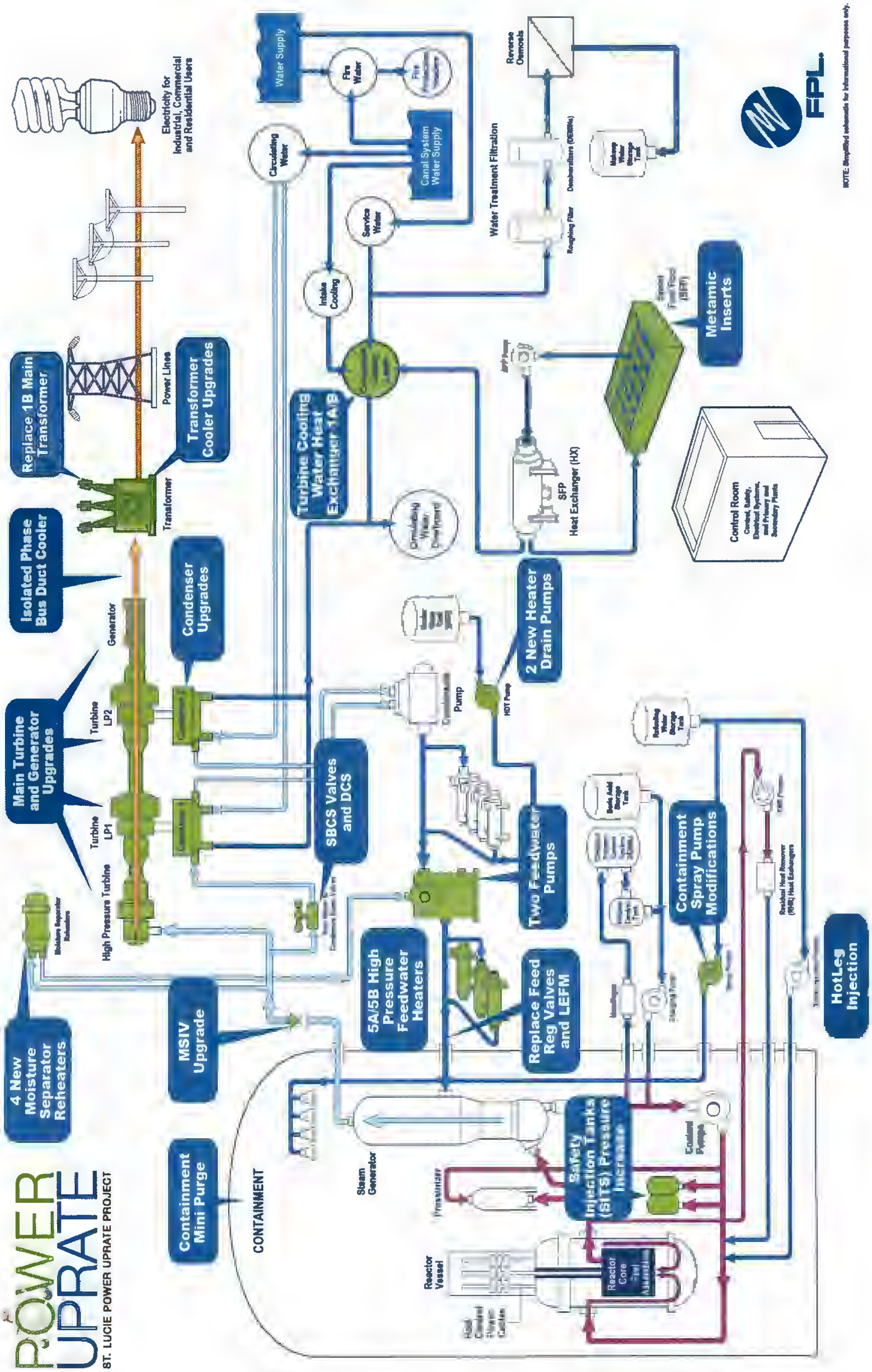
Turkey Point work on barriers for components of the CREVS/CREFS systems in very congested area.

CONTROL ROOM EMERGENCY VENTILATION AND FILTRATION SYSTEMS MODIFICATION (Continued)

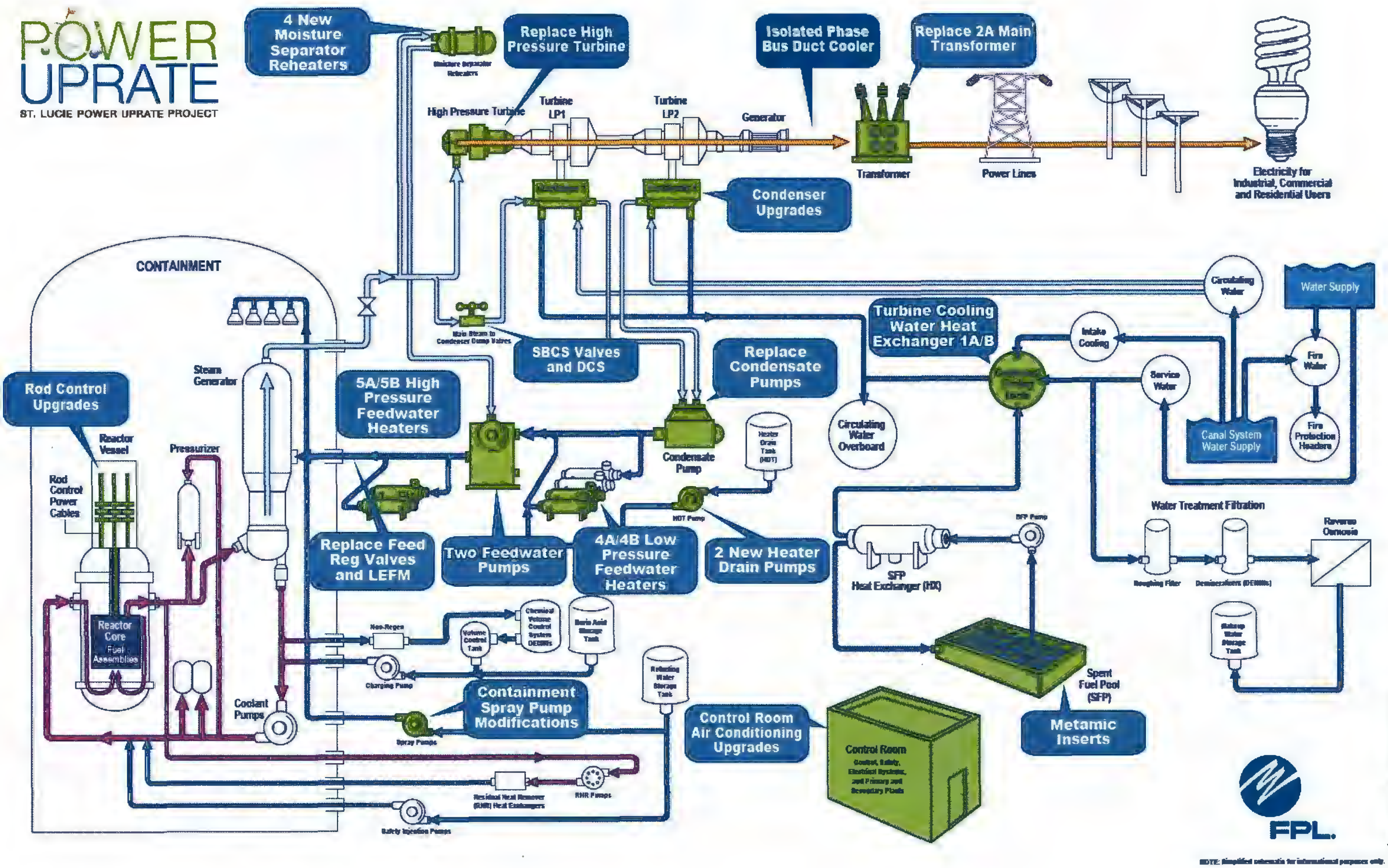


Turkey Point missile barriers for the CREVS/CREFS systems are complete.

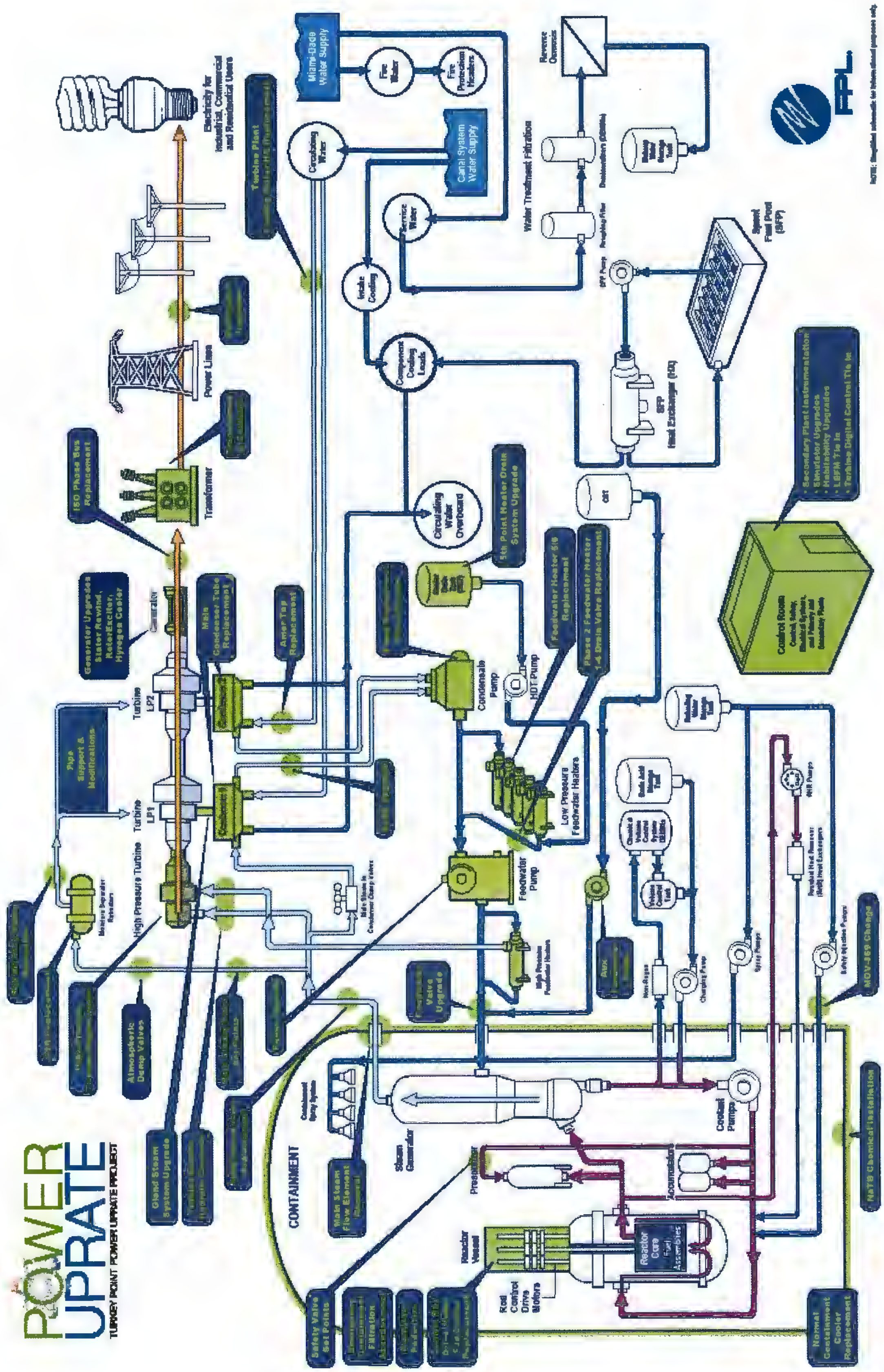
EPU Work Scope Completed at St. Lucie Unit 1 in 2012



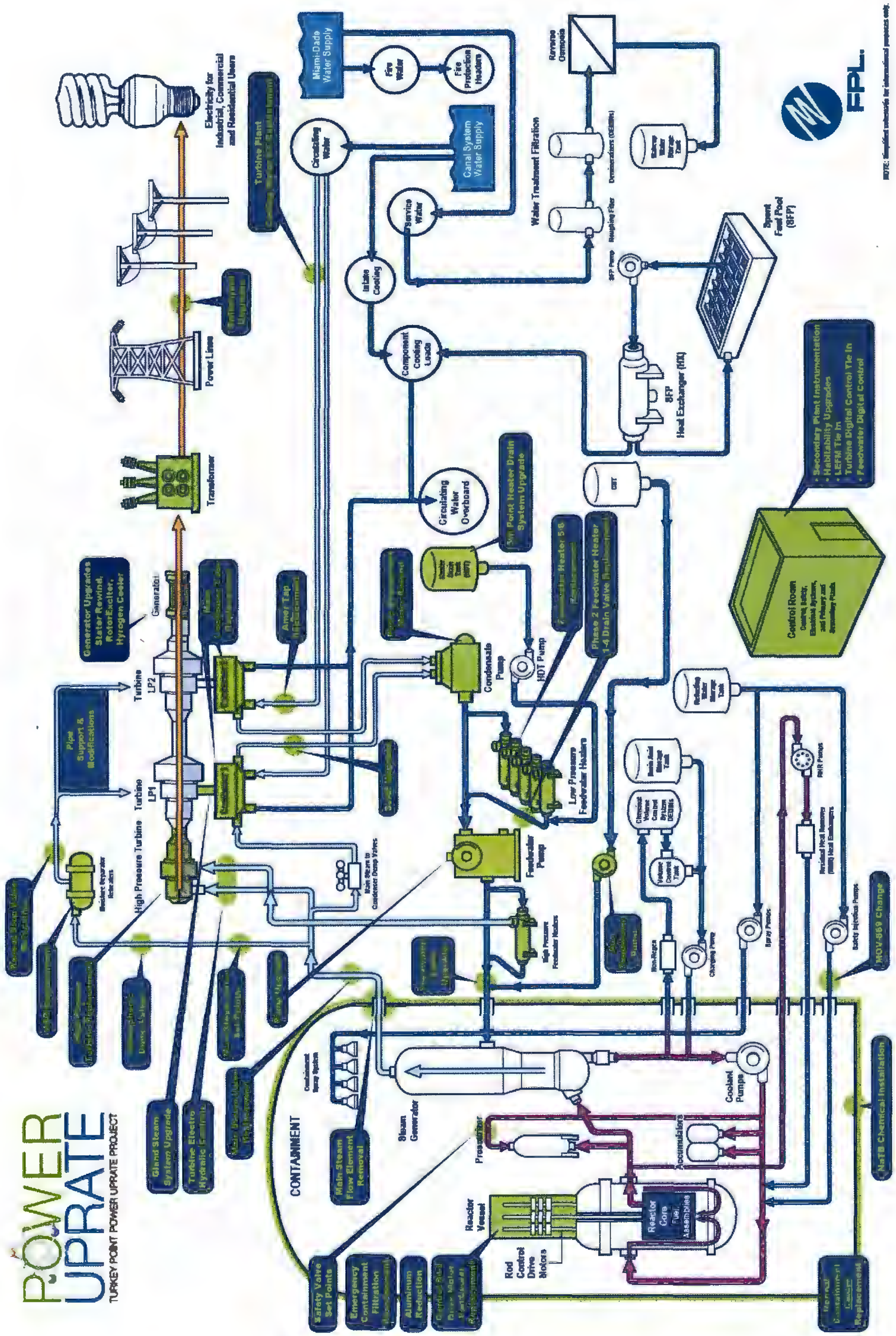
EPU Work Scope Completed at St. Lucie Unit 2 in 2012



EPU Work Scope Completed at Turkey Point Unit 3 in 2012



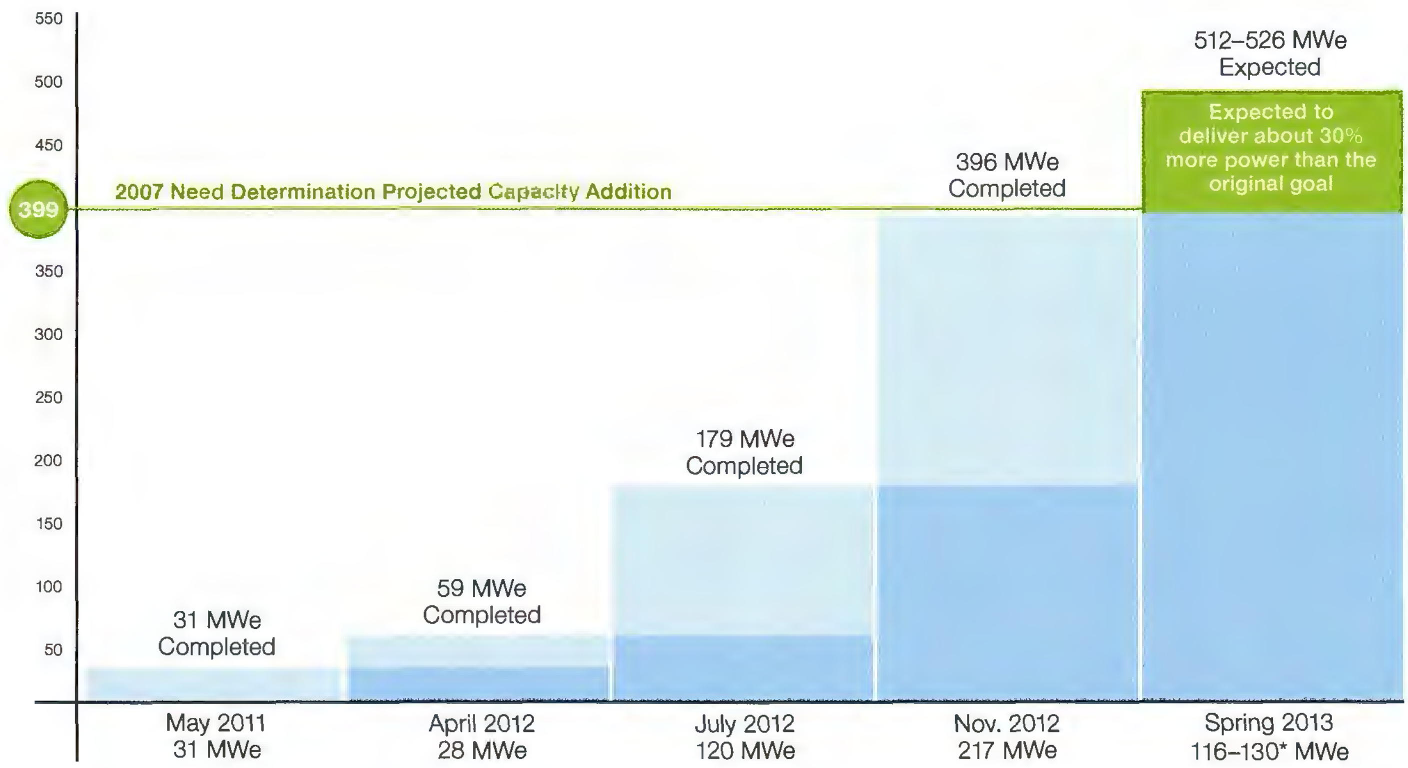
EPU Component Work Scope In-Progress to Complete Early 2013



TOJ – 5

Extended Power Uprate Project Expected to Deliver 30% More Capacity than Originally Projected

Unit Electrical Output Status in MWe through Dec. 31, 2012 and Estimated MWe at Completion



* Estimate

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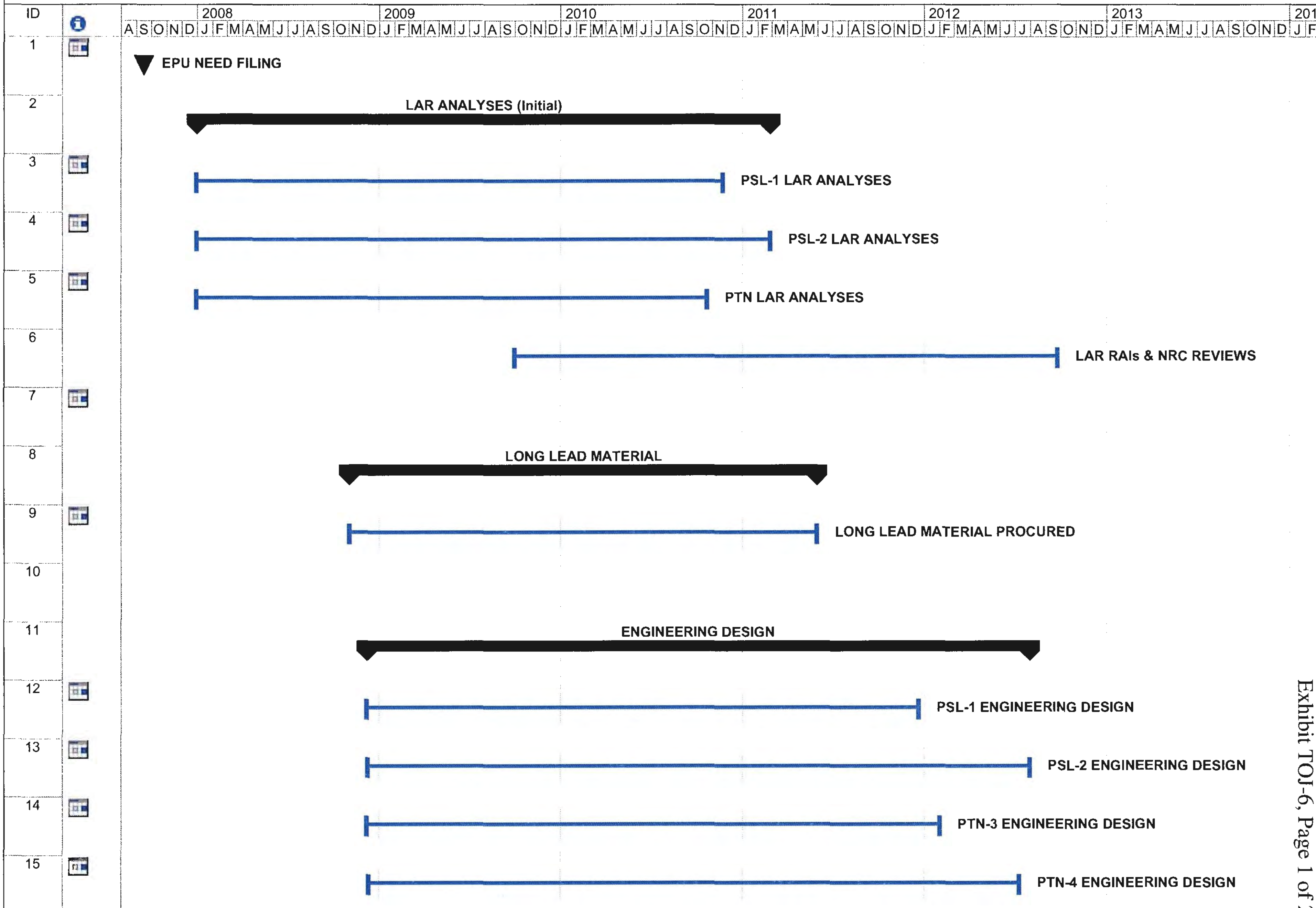
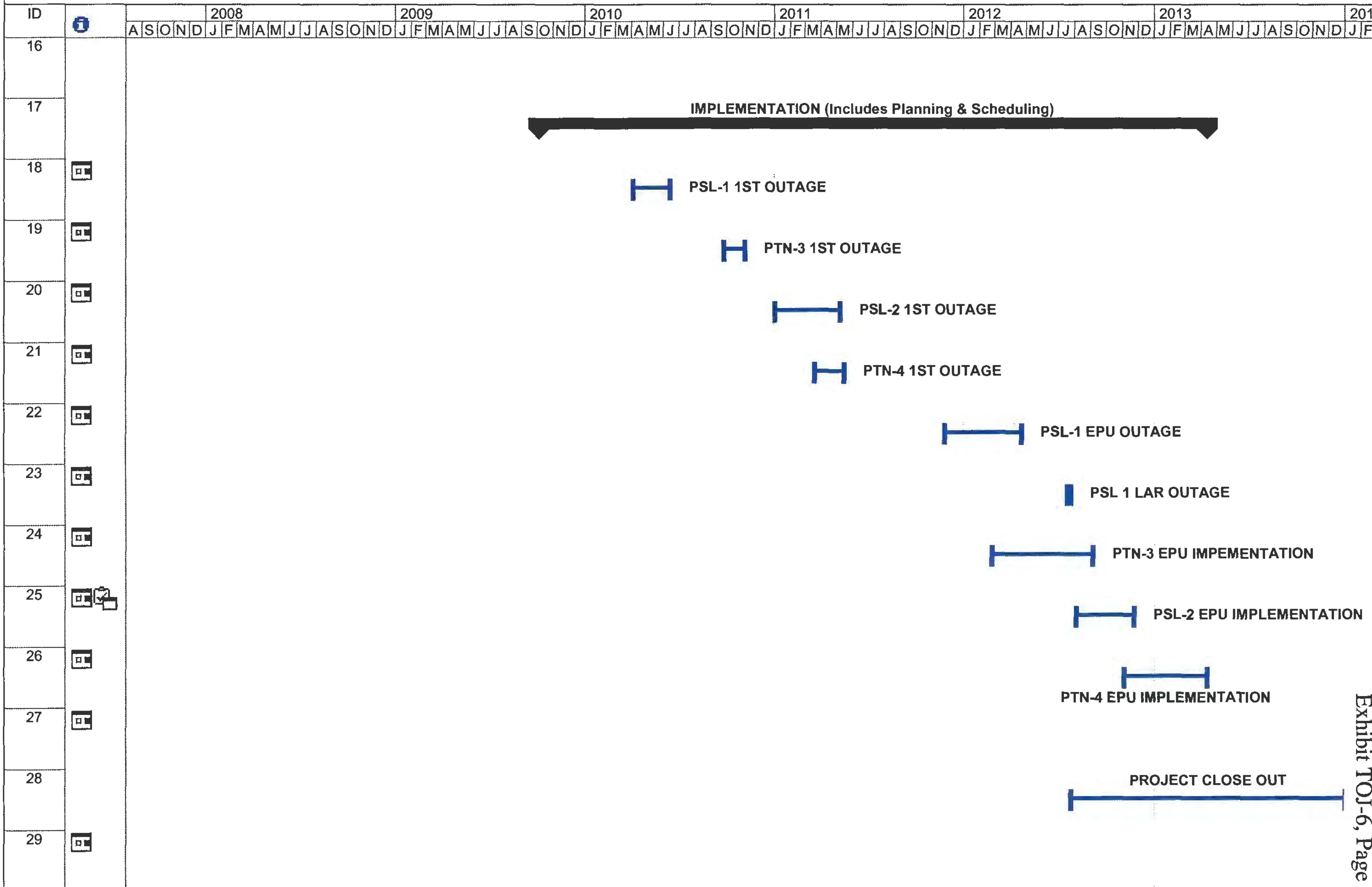
EPU Project Schedule Overview



EPU Project Schedule Overview



As of 12/31/2012

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2012 EPU COST VARIANCE DRIVERS

Three major nuclear plant outages for EPU modifications requiring over 12,000,000 professional and skilled craft man hours have been successfully completed in 2012 providing FPL customers the benefit of approximately 400 MWe. Ultimately, the human effort required to perform such a complex project is the major cost driver. This document discusses the complexities encountered in 2012 that contributed to FPL's final 2012 EPU project costs, as compared to the costs included in its Actual/Estimated (A/E) schedules filed on April 27, 2012. For the reasons discussed below, the St. Lucie work was completed with an approximately $48 million variance to FPL's 2012 A/E filing and the Turkey Point work was completed with an approximately $279 million variance to FPL's A/E filing. The 2012 A/E filing reflected actual costs through February 2012 and an estimate for remaining 2012 costs developed in March 2012, while this exhibit contains information known as of December 31, 2012.

St. Lucie EPU Modifications and System Commissioning

The majority of the EPU modifications performed during the St. Lucie Unit 1 outage were not routine, predictive or preventative maintenance activities but were first time evolution of major modifications which affected many large pieces of equipment and components, where interferences had to be removed to provide access. During component removal additional discovery required added engineering design, scheduling and planning, constructability reviews and ultimately more time than planned to perform the required modifications. Performing these EPU modifications on a licensed plant required added care and safety considerations to ensure nuclear regulatory requirements were satisfied. These factors added to the complexity of performing the modifications which were contributors to the longer duration, and increased staffing levels, of the St. Lucie Unit 1 outage.

Below are several exemplar modification descriptions where design, implementation, and constructability complexities were successfully resolved by the project team.

The installation of the **Isolated Phase Bus Duct** required far more engineering design hours, implementation time, implementation manpower, and raw materials than FPL estimated as a result of conditions that could not be discovered until the implementation of the modification began. The Isolated Phase Bus Duct is piping that serves as a conductor of electricity from the main generator to the main step up transformer where the low voltage is transformed into high voltage power for transmission. The piping is enclosed in duct work which allows it to be cooled. Additional interferences to the implementation of this modification were discovered, requiring additional field engineering to engineer the removal and reinstallation of the interferences. Additionally, once the new, bigger equipment was installed, there was less room for the orientation of the cooling water flange as originally planned. As a result, FPL had to cut, change the orientation, and weld the cooling water flange to properly connect it to the cooling water piping.

This modification required an additional 21,382 man hours of engineering and craft implementation work.

The modifications required for the two 34 inches-in-diameter main steam piping, **Main Steam Isolation Valves (MSIV)** included upgrading the valves and actuators and providing a backup actuator operating system to ensure operability at EPU steam flow conditions. The MSIVs close by actuator operation in the unlikely event of a main steam line break in the piping between the valves and the main turbine stop valves. Additionally, each of these valves have another valve in the same assembly which is a check valve which only permits steam flow in one direction and are designed to close if there is a main steam line break between the steam generator and the MSIV. The modification to these valves included upgrades to the valve internal components and the addition of larger actuators and a backup system to prevent inadvertent closure of the MSIVs. These valves are located in a very close proximity work area and the larger actuators and supports for the actuators added to the constructability complexity. Adding to the engineering design evolutions and constructability difficulties of close working space was the installation of the nitrogen gas backup system to ensure reliable valve operation which required additional piping and tubing runs to be installed. Adding to the complexity of this modification was the added wiring needed to support the MSIV modifications which required additional wiring runs, terminations and testing in very close spaces.

This modification required an additional 12,517 man hours of engineering and craft implementation work. Piping commodities related to this modification increased by approximately 100% and electrical commodities increased by approximately 79%.

Replacement of the two **Main Feedwater Pumps** was required for Uprate conditions. Engineering analysis determined that the existing motor rotor was insufficient and needed to be upgraded to 6.9 kv. The replacement motor was removed and sent offsite for refurbishment. This required additional electrical and mechanical disconnections and reconnections. The existing pump supports and piping required significant modification. Testing of the new system indicated the welding of the vent valves was inadequate for the new vibration levels and required a new design which resulted in a new piping configuration and additional supports.

This modification required an additional 27,121 man hours of engineering and craft implementation work.

The **Containment Mini Purge** modification was required due to the decrease in the maximum operating atmospheric pressure as a result of the EPU accident analysis. The modification was designed to allow remote control versus local manual operation. Purge isolation valves, flow control valves and purge fans required modifications to be operated from the control room. Radiation dose levels in the work area were considerably higher than expected and this required additional manpower for rotational purposes during implementation.

This modification required an additional 19,026 man hours of engineering and craft implementation work.

Additional commodities were required and installed during the St. Lucie Unit 1 outage and prior to and during the Unit 2 outage to support the modification work. Increases in the amounts of commodities to support modifications required additional engineering design, planning and scheduling, and skilled craft for implementation, all of which required added resources and more time to complete. The below table provides a list of the major commodities, the planned and actual amounts, the increase and the percentage increase:

St. Lucie Unit 1 and Unit 2 Outage Commodity Totals

Commodity	Unit of Measure	Plan	Actual	Actual - Plan = Increase	% increase above Plan
Large Bore Pipe Welds - ≥ 2.5" dia.	ea	932	1,220	288	31%
Large Bore Supports	ea	319	365	46	14%
Small Bore Pipe Welds	ea	2,494	2,934	440	18%
Electrical Wiring Conduit	Ft	19,856	19,944	88	0.4%
Electrical Cable	Ft	82,161	97,208	15,047	18%
Electrical Terminations	ea	19,362	20,744	1,382	7%

Note: Quantities from major vendor reports

Following the implementation of the modifications a systematic turnover to operations is required to ensure the system would perform its function reliably after implementing the EPU modifications. This required engineers, Instrumentation and Control (I&C) technicians, and craft support to test the various system controls, logic functions, and verify and validate system operability. This manpower-intensive commissioning effort experienced complexities and also contributed to the longer duration of the outage. Two examples at St. Lucie Unit 1 follow.

Power Ascension Testing revealed that one of the feedwater pumps had high vibrations shortly after pump startup, which was addressed by the testing engineers, technicians, and craft. One of the steam bypass control valves opened inadvertently, and plant operators correctly responded to the event by shutting down the reactor. The discharge of the steam bypass control valve is through a sparger which is physically located in the main condenser. Following the inadvertent cycling of the steam bypass control valve, the sparger required replacement.

Condensate and Feedwater Chemistry took longer than expected to bring within specification. Each of the nuclear units strictly adheres to the industry good practice limits on secondary water chemistry. This is done to extend the life of the steam generator materials. The large number of components and piping replaced during the outage required extensive circulation of the secondary water through a clean up system until proper chemistry specifications were met before the feedwater could be pumped into the steam generators to begin the steam cycle.

Weather impacted the St. Lucie Unit 2 outage during August and September 2012, including Tropical Storm Isaac. The main turbine, turbine generator, feedwater heaters, and many other major components are located outdoors. Typically, FPL nuclear unit outages occur in the spring and fall seasons when rainfall averages are significantly less than the August and September totals and the daytime temperatures are more conducive to peak outdoor construction productivity. Additionally, humidity and warmer temperatures creates reduced worker productivity rates due to hydration issues. The Occupational Safety and Health Administration (OSHA) regulatory guidelines provide for necessary worker rest periods when humidity and temperature are at issue. Craft workers are typically sent home if significant rainfall is expected in order to reduce costs. This, in turn, impacts progress and productivity with additional "stops and starts" as opposed to a work condition in which there is a continuous flow of activities from beginning to end of a scheduled shift. Storm preparation, direct impact, and restoration affected approximately four days of production during the St. Lucie Unit 2 EPU outage. This weather event reduced some costs, since workers were sent home, but also was a contributing factor to the loss of overall actual construction progress versus planned progress during this time frame.

Using the talents of and experience gained by personnel who performed the St. Lucie Unit 1 outage, the St. Lucie Unit 2 outage engineering designs, planning and scheduling, and work packages were enhanced as well as the planning for the St. Lucie Unit 1, six-day License Amendment Request (LAR) outage where instrumentation and parameter scaling and setpoints were changed and procedures implemented for operation in the uprate condition. Preparing for the St. Lucie Unit 1 LAR outage and the St. Lucie Unit 2 EPU outage in this manner required increased staffing levels in between the outages, contributing to increased costs. As a result, and despite the weather challenges as previously discussed, the St. Lucie Unit 2 outage duration was 25% better than the Unit 1 outage and cost approximately 18% less than the cost for the Unit 1 outage.

All the efforts described above contributed to the additional resources required to implement the St. Lucie EPU project and resulted in a total increased cost of approximately $48 million in 2012. The results were the successful completion of the St. Lucie Unit 1 EPU and LAR outages and the St. Lucie Unit 2 EPU outage in 2012, with the addition of approximately 280 MWe of clean, greenhouse gas-free electricity being provided for the benefit of FPL customers.

The below table is a summary of the 2012 St. Lucie EPU cost variances which includes the vendor or category, the NFR Actual/Estimated 2012 costs, the actual 2012 costs, the variance and an explanation of the variance.

Vendor/ Category	Actual/ Estimated 2012 Cost	Actual 2012 Cost	Variance 2012 Cost	Variance Explanation
License Amendment	$17,087,333	$26,687,697	$9,600,364	This category includes the support of Westinghouse, Shaw, Areva, other engineering contracts and the NRC fees related to the preparation, submittal, review and approval of the St. Lucie Unit 1 and Unit 2 License Amendments, and the "umbrella modification" which implements the requirements of the LAR . The variance is due primarily to the NRC longer-than-expected review time and the complexity of the LAR and the cost of additional vendor and Owner labor to respond to NRC requests for additional information and implementing the LAR requirements.

Vendor/ Category	Actual/ Estimated 2012 Cost	Actual 2012 Cost	Variance 2012 Cost	Variance Explanation
FPL Owner Engineering	$7,253,671	$9,996,255	$2,742,584	The variance is the result of Owner support of the design engineering effort for Unit 1 and Unit 2 modifications. Additional overtime was worked to ensure readiness for the Unit 2 outage.
FPL Owner Project Management	$19,494,825	$20,349,720	$854,895	The variance primarily reflects the additional overtime required to support the longer Unit 1 outage start up and testing phase.
Bechtel	$101,768,246	$171,940,418	$70,172,172	The majority of the EPU modifications performed during the Unit 1 outage were first time evolutions of major modifications which affected major pieces of equipment and a variety of components. The variance is the result of the iterative integration of final licensing requirements, existing field conditions, and vendor design details for engineered equipment and components. In many instances, the design details required additional modifications after initial issuance to accommodate discovery. Additionally, the variance reflects an increase in work package planning staff to complete work packages, requisition materials, and support turn-over packages. Impacts were also experienced from the heavy rainfall and tropical Storm Isaac safety preparedness during August 2012 time frame. All of these factors contributed to the additional non-manual and craft human capital required to successfully complete both PSL outages in 2012. Removal costs are excluded.

Vendor/ Category	Actual/ Estimated 2012 Cost	Actual 2012 Cost	Variance 2012 Cost	Variance Explanation
Turbine Generator Component Material	$37,558,738	$35,864,500	($1,694,238)	This variance reflects the payments to Siemens made pursuant to the agreement executed in July 2012.
Turbine Generator Installation Services	$48,025,173	$41,981,499	($6,043,674)	The major contributors to the variance were the successful completion of the Unit 2 scope of work significantly under budget and the payments to vendor that were made pursuant to the agreement executed in July 2012.
Station Indirect Outage Cost	$22,155,957	$26,316,343	$4,160,386	The variance was caused primarily by the extended Unit 1 outage and the associated incremental station support costs.
Engineering and Implementation (other than Bechtel and Siemens)	$50,222,006	$54,500,703	$4,278,697	This category includes Shaw Construction, AMES, Bartlett, Williams, Master Lee and a number of other support contractors. Also included is the cost of personnel responsible for procedure updates, startup, and testing. The variance was caused primarily by new scope added to the Shaw Construction contract for Digital Electro-Hydraulic (DEH) mechanical and electrical installation in the Unit 1 outage. This work was assigned to Shaw to achieve greater schedule certainty.

Vendor/ Category	Actual/ Estimated 2012 Cost	Actual 2012 Cost	Variance 2012 Cost	Variance Explanation
Risk / FPL purchased Long Lead Material	$66,991,579	$28,071,142	($38,920,437)	This category includes the FPL purchased Long Lead materials and the funds associated with risk identified at the time of the previous submittal. The variance primarily reflects the removal of costs from risk/contingency to base budget after scope was defined and approved for inclusion in the project.
Non-Power Block Engineering, Procurement, etc.	$111,010	$278,339	$167,329	This category includes the Simulator which required additional work scope to complete the required upgrades.
Transmission	$14,175,657	$17,490,506	$3,314,849	This category includes plant engineering, line engineering, substation engineering, and line construction. This variance is a result of the installation of the new main transformer at St. Lucie Unit 2 taking longer than estimated.
Recoverable O&M	$3,947,588	$3,104,433	($843,156)	This category includes modifications that did not meet the capitalization criteria, O&M EPU equipment inspections, and obsolete inventory write-offs. The variance is primarily attributable to fewer obsolete inventory write-offs than estimated for 2012.
TOTAL	**$388,791,783**	**$436,581,554**	**$47,789,771**	

Turkey Point EPU Modifications and System Commissioning

The majority of the EPU modifications performed during the Turkey Point Unit 3 outage were not routine, predictive or preventative maintenance activities but were first time evolution major modifications which affected many large pieces of equipment and components, where interferences had to be removed to provide access. During component removal additional discovery required added engineering design, scheduling and planning, constructability reviews and ultimately more time than planned to perform the required modifications. When a modification activity is started it is necessary to resolve discovery challenges to ensure the modification is completed safely and efficiently. Performing these EPU modifications on a licensed plant required added care and safety considerations to ensure nuclear regulatory requirements were satisfied. These factors added to the complexity of performing the modifications which were contributors to the longer duration of the first Turkey Point Unit 3 outage. It was necessary to increase staffing levels and keep people longer to complete these first time modifications and prepare for the Turkey Point Unit 4 outage.

Below are several exemplar modification descriptions where design, implementation, and constructability complexities were successfully resolved by the project team.

The **PTN Control Room Emergency Ventilation System and Control Room Filtration System (CREVS/CREFS)** modifications were not included in the original scope.

The initial Control Room Habitability modifications only required the installation of containment sump pH Control modification which consisted of the installation of Sodium Tetraborate Baskets and removal of the Emergency Containment Filters. The need for CREVS/CREFS was identified during the Alternative Source Term (AST) license amendment engineering analysis phase. The new modification included a complex replacement and redesign of structural supports associated with the CREVS/CREFS fans and relocation of existing outside air intakes. Relocation of existing air intakes required additional seismic and missile protection design to meet safety related design requirements. The NRC-required modification to upgrade the Control Room CREVS/CREFS became very complex due to the limited available real estate and strict regulatory requirements. The capability of the CREVS/CREFS, along with the Control Room Boundary (CRB) and Control Room Envelope (CRE) is to provide an acceptable environment for control room personnel and equipment such that the reactor can be safely controlled under normal conditions and maintained in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. There were several engineering design evolutions during the constructability and planning portion of the modification and during the implementation of the modification due to discovery. Special seismic and missile protected structures and heavy wall piping were installed to move outside filtered air from the units to the control room. Added seismic piping supports and seismic structures that hold the ventilation fans and dampers and the filtration portion of the systems required additional planning and manpower to implement due to the complexity of the modification. The PTN Control Rooms require special processes, procedures, risk evaluations, and look-ahead activities to permit breaching the control room envelop. These precautions are based on operating restrictions placed on both units during a boundary breach. There were numerous separate breaches required to install the necessary cables into the control room. Each control room envelop breach was scheduled well in advance and was subject to schedule impacts due to emergent plant operating issues, thereby affecting craft productivity.

This modification was impacted greatly by the iterative nature of the work wherein each pipe hanger required multiple revisions as the resulting changes to accommodate available pipe support anchor bolt locations (drilled into existing reinforced structures) had to be evaluated for wind and seismic conditions. The number of Large Bore (LB) pipe supports grew 500% and the number of LB welds increased by 40%. There were significant modifications required as many of the structural connections were made to existing steel or were made to embedded structures that often varied from the design basis (note: this is not uncommon for plants of this vintage).

The project team estimated that this modification would require 11,200 man hours of engineering and 72,066 man hours of field implementation. It actually required 15,502 man hours of engineering and 218,173 man hours of field implementation in year 2012.

The **PTN Main Condensers** have canal cooling water pumped at approximately 1,300,000 gallons per minute through over 110,000 tubes to condense over 12 million pounds mass per hour of steam being discharged from the low pressure turbines. The condensate is then reheated and pumped into the steam generator to again begin the steam cycle. A larger condenser was needed to support increased steam flow at EPU conditions. Replacing the main condenser required far more engineering design hours, implementation time, implementation manpower, and raw materials than estimated as a result of location congestion and conditions that could not be discovered until the implementation of the modification.

There were a significant number of as-found conditions that needed to be addressed on an emergent basis after the outage started. The nature of the condenser work was such that: 1) most areas could not be accessed while the plant was operating which did not allow the existing conditions or the constructability of the new design to be validated; and 2) required many activities to work in series which limited the ability to mitigate schedule impacts by executing other work fronts in a parallel path manner. These conditions included, but were not limited to, the following items:

- Low pressure Feedwater Heaters (FWH) temporary supports. The existing "neck heaters" needed to be temporarily supported when the condenser tubes and tube sheets were removed. The as-found location of the neck heaters was different than the design location which required a redesign of the temporary supports. The sequencing of the work required these temporary supports to be installed before other work could progress, so the emergent identification and resolution of this issue was a significant schedule and cost impact.
- There were a number of plugged tubes (approximately 2,000 out of approximately 58,000) that had to be cut out individually and manually versus the planned mechanical extraction.
- As an extent of condition evaluation following a sparger failure at St Lucie, the spargers inside the Turkey Point Unit 3 condenser were evaluated for corrosion and operability in the uprate conditions. A number of spargers were identified for replacement; the repair/replacement locations interfered with originally planned work and the emergent nature of the work resulted in material delays which further impacted the planned work sequence.

Initially, FPL planned to use portable cranes to move the old condenser out and the new condenser into place. However, it was later determined that there was simply not enough land area suitable to stage a portable crane or maneuver the large loads. Accordingly, a specialty track crane was designed. This required the installation of micro piles, to prevent disturbing existing underground utilities, for one crane rail and the use of one of the turbine gantry crane rails for the other rail of the temporary crane. The scheduling of crane use was critical to ensuring worker and equipment safety, as both the turbine building crane and the condenser crane could not be used at the same time. Additionally, the foundation of the condenser could not be assessed until the old condenser was removed. Upon removal, it was determined that it was necessary to upgrade the foundation steel and concrete for the new condenser, which required additional time for engineering design, planning, and scheduling, as well as additional commodities. Additional discovery of needed upgrades to spargers that distribute steam as it enters the condenser required added materials to upgrade the spargers for EPU conditions. The spargers required added engineering design, materials, planning, and implementation, all of which added to the complexity of the condenser work.

The estimated engineering and field implementation for the condenser replacement was 215,900 man hours. The condenser replacement including the temporary specialty crane took approximately 368,090 man hours of engineering and field implementation work.

The **PTN Spent Fuel Pool Cooling System** provides cooling to the spent fuel storage pool to keep used fuel cooled within regulatory specifications during initial off-loading of the fuel assemblies from the reactor vessel and for long term cooling. Due to the use of new fuel to provide the increased power for the uprate conditions, the spent fuel pool cooling system required modifications which included installation of a new heat exchanger on a new platform and more piping in a very congested room. Numerous interferences were removed and redesigned to install the new cooling system while keeping the original system in service. Detailed coordination between operations personnel, the engineers, and the constructors was required to safely resolve these interferences. The engineering design required cutting a large hole in a thick concrete wall used to protect the system components and contain radiation. The opening in the wall took much more time and engineering than originally planned. This was another first time evolution performed in a highly congested space. The interferences that needed to be relocated had to have the same quality as the original equipment to ensure safe continued system operability. Additionally, this work required contamination and radiation protection safety controls to keep the radiation dose to workers As Low As Reasonably Achievable (ALARA) and to minimize the potential for radioactive contamination of workers. This was accomplished with extensive planning, training of workers and worker familiarity with tools and equipment. This work took more engineering design, planning and scheduling, constructability reviews and implementation workers than estimated. This modification required an additional 77,465 man hours of engineering and craft implementation work.

The **PTN Normal Containment Cooling System (NCC)** is another example of design engineering, planning and scheduling, constructability, and implementation complexities that occurred during the required replacement modification for the NCC in the cramped areas of the primary containment building. These coolers provide necessary area cooling of the primary containment during plant operation and outage periods. The increased heat loads and the requirement to reduce aluminum metal concentration in the primary containment building required replacing the normal containment coolers with larger, non-aluminum coolers for operation in the uprate condition. The new cooler components are substantially more robust than the existing components and therefore required significant structural modifications to support the increased weight. The final support design identified numerous changes to the structural modifications. The work was critical path to the outage and required more resources than originally estimated to complete the implementation. This work required contamination and radiation protection safety controls to keep the radiation dose to workers ALARA and to minimize the potential for radioactive contamination of workers. This was accomplished with extensive planning, training of workers and worker familiarity with tools and equipment. Two different mockups were used to train and prepare workers for the removal and replacement of the NCCs, one was the erection and operation of a small crane to move the many materials and components inside the containment building and the other was the physical structural placements of the NCCs, both of which were performed outside the primary containment building. Once work began in the primary containment building, equipment lay-down and staging areas were extremely limited and it was necessary to erect a platform over the reactor cavity to provide additional work space. In addition to the needed lay-down and staging area more equipment interferences needed to be moved to accommodate movement and placement of the NCCs. Larger structural steel supports and piping were needed for the new larger replacement NCCs which required additional commodities, resources, and time to complete the work in the cramped areas while working in protective clothing.

This modification required an additional 130,834 man hours of engineering and craft implementation work. Small bore piping welds increased by over 400%, electrical conduit which supports electrical wiring runs increased by over 1,200%, in addition to the large increase in the amount of structural steel supports.

The **PTN Turbine Deck** is where the major work scope was for replacing components. The Turbine Generator Original Equipment Manufacturer (OEM), implementation contractor, performed the High Pressure Turbine upgrade, High Lift modification, and Main Generator upgrade. The EPC contractor replaced Feedwater Heaters 5 & 6, replaced four Moisture Separator Reheaters, installed the new Electro-Hydraulic Controls (EHC) system, and implemented the Gland Steam modification. These activities are complicated by usage of a single Turbine Gantry Crane, common lay-down spaces and work spaces, which required detailed coordination between all contractors involved. Due to the limited availability of the turbine gantry crane, a large tower crane and several small lift cranes were temporarily installed which provided increased capability to perform lifting activities simultaneously but also required detailed coordination. Further complicating the turbine building scope is the heavy load analysis which restricted movement of major components due to regulatory requirements. In addition, there were several new systems/components installed by the EPC contractor that are in close proximity to the turbine generator OEM contractor and thus required greater coordination to ensure safety (e.g., the HP turbine, EHC system, and Gland Steam system). Initially the plan was to use existing electrical cable raceways and conduits for the EHC system upgrade. During the detailed design phase of the turbine EHC system, it was determined that existing electrical cable raceways and conduits were not adequate for the new digital controls. Accordingly, new electrical cable raceways, conduits, and associated supports were required for cable routing. Additionally, the turbine digital control system required a complex factory acceptance test and several design iterations to ensure reliability.

PTN has **Lead-Based Paint and Asbestos Insulation** which are considered hazardous materials when disturbed. Lead paint and asbestos abatement activities require personnel specially trained in hazardous material handling. For the safety of workers abatement was required prior to the demolition of existing systems, structures, and components and installation of the new equipment required for EPU. There was more abatement required than estimated which took hazardous material specially-trained personnel longer to complete.

The PTN **Feedwater Heater and Moisture Separator Reheater (MSR) Replacement Modifications** includes replacing the feedwater heaters, four MSRs and associated piping. During the detailed design phase, the turbine building was analyzed and found to require additional structural support modifications to accommodate installation of the new, larger and heavier feedwater heaters. With these structural modifications an overall turbine building seismic fragility model was developed to ensure the additional structural supports and turbine building were structurally adequate. Turbine building modifications were also required for the four MSR replacements. These activities required more resources than estimated.

There was also a general quantity growth across piping and hangers for these modifications as many of the assumptions could not be verified in the congested areas while the unit was operating. For the feedwater heaters, the final number of Large Bore (LB) pipe hanger quantities increased by 70% and LB piping welds increased by approximately 25%. For the MSRs, LB pipe hanger quantities grew by nearly 100%; and the LB piping welds by over 20%. The magnitude of these changes caused a significant increase in the craft hours and non-manual staffing hours needed to process the additional work.

This modification required an additional 244,198 man hours of engineering and craft implementation work.

Additional commodities were required and installed during the Turkey Point Unit 3 EPU outage to support the modification work. Increases in the amounts of commodities to support modifications requires additional engineering design, planning and scheduling, and skilled craft for implementation, all of which requires added resources and more time to complete. The below table provides a list of the major commodities, the planned and actual amounts, the increase and the percentage increase:

Turkey Point Unit 3 Project Commodity Totals - Pre-outage and Outage

Commodity	Unit of Measure	Plan	Actual	Actual - Plan = Increase	% increase above Plan
Misc. Structural Steel	piece	1,864	2,385	521	28%
Large Bore Pipe Welds - ≥ 2.5" dia.	ea	1,918	2,479	561	29%
Large Bore Supports	ea	614	860	246	40%
Small Bore Pipe Welds	ea	3,757	3,967	210	6%
Electrical Wiring Conduit	Ft	8,719	10,659	1,940	22%
Electrical Cable	Ft	81,824	81,879	55	0%

Note: Quantities from major vendor reports

Following the implementation of the modifications a systematic turnover to operations is required to ensure the system would perform its function reliably after implementing the necessary EPU modifications. This required engineers, technicians, and craft support to test the various system controls logic and verify and validate system operability. Included in this monumental effort of the commissioning of these systems are the technical and functional component and system interconnections and dependent functions of the many systems that were modified. This manpower intensive effort also added to the longer duration of the outage.

Weather impacted the Turkey Point Unit 3 outage. The main turbine, turbine generator, feedwater heaters, and many other major components are located outdoors. Rainfall and thunderstorms during the outage period had an impact on nearly all EPU work since most of the work occurred outdoors and in an open Turbine Building. The amount of rainfall during the outage period exceeded the historical average; according to NOAA, the local area experienced 64 inches of rainfall during the 6 month period from March 1 through August 31, 2012 as compared to an average rainfall of 36 inches for the same 6 month period. Additionally, there were frequent work stoppages due to lightning before, during, and after the rain storms. All crane activities were stopped for lightning strikes within a 10 mile radius around the site as a safety precaution and all work activities in open areas were stopped for lighting strikes within a five mile radius around the site. High winds were also a factor as wind gusts above 25 miles per hour shut down most cranes on site, impacting productivity.

Using the talents of and experience gained by personnel who performed the Turkey Point Unit 3 EPU outage the Turkey Point Unit 4 outage engineering designs, planning and scheduling, and work packages were enhanced. Preparing for the Turkey Point Unit 4 EPU outage in this manner required increased staffing levels in between the outages, contributing to increased costs. As of December 31, 2012, the forecast duration of the Unit 4 outage duration was 33% better than the Turkey Point Unit 3 outage, and the forecast cost to complete the PTN 4 outage was 20% better than the cost of the PTN 3 outage.

All the efforts described above contributed to the additional resources required to implement the Turkey Point EPU work and resulted in a total increased cost of approximately $279 million in 2012. Primary drivers for the Turkey Point variance by vendor are presented in the table below. The results were the successful completion of the Turkey Point Unit 3 EPU outage in 2012, with the addition of approximately 116 MWe of clean, greenhouse gas-free electricity being provided for the benefit of FPL customers.

PRIMARY DRIVERS FOR 2012 TURKEY POINT COST VARIANCE

Vendor/ Category	Actual/ Estimated 2012 Cost	Actual 2012 Cost	Variance 2012 Cost	Variance Explanation
License Amendment	$6,990,596	$7,912,881	$922,285	The variance was caused by the need for more engineering analyses to respond to NRC requests and extended NRC review times, offset to some extent by completing certain LAR engineering work on a Time & Materials basis for less than estimated.
Risk and O&M	$11,335,746	$4,684,330	($6,651,416)	The variance primarily reflects the removal of costs from risk/contingency to base budget after scope is defined and approved for inclusion in the project.

PRIMARY DRIVERS FOR 2012 TURKEY POINT COST VARIANCE

Vendor/ Category	Actual/ Estimated 2012 Cost	Actual 2012 Cost	Variance 2012 Cost	Variance Explanation
Bechtel	$332,761,410	$502,600,396	$169,838,986	The majority of the EPU modifications performed during the outage were first time evolution of major modifications which affected many large pieces of equipment and components. The variance is the result of the iterative integration of final licensing requirements, existing field conditions, and vendor design details for engineered equipment and components. In many instances, the design details required additional modifications after initial issuance to accommodate these factors and new information. Additionally, the variance reflects an increase in work package planning staff to complete work packages, requisition materials, and support turn-over packages. Specifically, the CREVs/CREFs, Normal Containment Coolers, Spent Fuel Pool, Condenser Replacement, Feedwater Heaters and Moisture Separator Reheaters, Electro-Hydraulic Tubing, Turbine Digital Controls, Main Steam Isolation Valves, and Main Feedwater Pump modifications were impacted. The need to use multiple temporary construction cranes to access nearly all of the modification areas at Turkey Point also contributed to complexity and costs. Removal costs are excluded.
Turbine Generator Material	$29,659,103	$36,422,802	$6,763,699	This variance reflects the payments to vendor that were made pursuant to the agreement executed in July 2012.

PRIMARY DRIVERS FOR 2012 TURKEY POINT COST VARIANCE

Vendor/ Category	Actual/ Estimated 2012 Cost	Actual 2012 Cost	Variance 2012 Cost	Variance Explanation
Turbine Generator Installation and Material	$70,914,024	$90,183,082	$19,269,058	The major contributors to the variance were the unanticipated scopes covered under Extra Work Authorizations (EWAs), as-found conditions covered under EWAs, and the actual outage duration lasting longer than anticipated. Major contributors to EWAs included: alignment of the Low Pressure (LP) and High Pressure (HP) turbine internals, replacement of the generator building bolts, and Electro-Hydraulic Controls, Power System Stabilizer, and Voltage Regulator specialists and supporting equipment. Another contributor to the variance was the costs associated with keeping vendor personnel on site performing work for a longer duration than planned, contributing to regular and overtime work hours. Cost also increased due to the following: exciter coupling work, lead abatement, re-insulation of leads, replacement of rotor flux probes, replacement of iris slot couplers, and additional hours needed for the installation and testing of the power system stabilizer.

PRIMARY DRIVERS FOR 2012 TURKEY POINT COST VARIANCE

Vendor/ Category	Actual/ Estimated 2012 Cost	Actual 2012 Cost	Variance 2012 Cost	Variance Explanation
Shaw (Construction)	$0	$37,191,194	$37,191,194	The variance was caused primarily by new scope added to the Shaw contract for completion of some portion of the NCC and Control Rod Drive Mechanism cooling fans work for Unit 3 and for the Radiological Control Area (RCA) work and Spent Fuel Pool Cooling upgrade support for PCI on Unit 4. This work was assigned to Shaw to achieve greater schedule certainty and allow for the EPC contractor to focus on secondary side modifications.
Williams	$0	$4,851,549	$4,851,549	The variance was caused by added scope to abate lead based paint prior to demolition of existing systems, components and structures. Additional scope was added for cleaning and coating of all pipe spools and equipment, and to wash down all piping installed for the EPU modifications.
WeldTech	$0	$8,655,566	$8,655,566	The contract was issued for completion of the steam jet air ejector modification, gland steam piping, condensate piping and supports, and sparger replacement work for Unit 3. The contract was modified to add the same scope for EPU Unit 4 implementation. This work was assigned to Weldtech to achieve greater schedule certainty and allow for the EPC contractor to focus on secondary side modifications.

PRIMARY DRIVERS FOR 2012 TURKEY POINT COST VARIANCE

Vendor/ Category	Actual/ Estimated 2012 Cost	Actual 2012 Cost	Variance 2012 Cost	Variance Explanation
PCI, Westinghouse Co.	$0	$13,702,295	$13,702,295	Following completion of the Unit 3 spent fuel pool cooling upgrade modification, competitive bids were solicited for the Unit 4 scope. PCI was awarded the contract for installing the Unit 4 spent fuel pool cooling upgrade modification prior to the Unit 4 outage. This work was awarded to PCI to achieve greater schedule certainty for Unit 4 outage completion and to allow for the EPC contractor to focus on secondary side modifications. PCI successfully completed the Unit 4 work prior to the Unit 4 outage.
Station Support and Ames	$20,467,351	$32,477,630	$12,010,279	Along with Station support staff, Ames was contracted to install I&C equipment and cable terminations for Units 3 and 4 to expedite completion of Engineering Change Modification and turnover to Start Up for testing according to the post modification plan. This work was assigned to Ames to achieve greater schedule certainty and allow for the EPC contractor to focus on secondary side modifications.
FPL Project Management / FPL Engineering	$50,838,246	$52,413,289	$1,575,043	This variance was caused by increased staffing and extended overtime work for FPL supervision and staff to adequately oversee the complex work and issues discovered during implementation, as well as the need for oversight over a longer duration than planned. The variance was mitigated by less than planned FPL Engineering costs.

PRIMARY DRIVERS FOR 2012 TURKEY POINT COST VARIANCE

Vendor/ Category	Actual/ Estimated 2012 Cost	Actual 2012 Cost	Variance 2012 Cost	Variance Explanation
Implementation Support, Other Engineering / Long Lead Material	$176,715,620	$189,015,121	$12,299,501	The variance is the result of the need for additional engineering subcontractors and FPL Plant support to address increased scope caused by existing field conditions and revisions to vendor design details for engineered equipment and components. The following also contributed to this variance: (i) Radiation Protection (RP) staff, consumables, and test equipment was required for a longer duration than planned, and the RP coverage requirement changed from intermittent coverage to constant coverage during the outage; (ii) security personnel were also needed to monitor increased traffic, parking areas, access, and material logistics for a longer duration than planned; (iii) FPL needed to procure an additional offsite facility for employee processing and an additional facility for welder testing; (iv) FPL incurred costs to consolidate material storage facilities and material logistics to ease access of material for various contractors for EPU implementation as a lesson learned from Unit 3 outage; (v) additional material and commodities were required to support the EPU modifications; (vi) and FPL issued purchase orders to suppliers to bring their technical representatives for critical systems to standby during the start up activities for outages to mitigate delays to resolve unforeseen issues.

PRIMARY DRIVERS FOR 2012 TURKEY POINT COST VARIANCE

Vendor/ Category	Actual/ Estimated 2012 Cost	Actual 2012 Cost	Variance 2012 Cost	Variance Explanation
Transmission	$13,214,482	$12,224,503	($989,979)	This category includes plant engineering, line engineering, substation engineering, and line construction. This variance is a result of the work requiring less resources than estimated to complete.
TOTAL	**$712,896,578**	**$992,334,638**	**$279,438,060**	

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2012 Extended Power Uprate (EPU) Project Work Activities

St. Lucie Unit 1R24 2011/2012 Outage	Description	Contract	Scoping Document
Condenser Material Modifications includes air removal	Strengthening of the Main Condenser is needed with higher steam and condensate flows in the uprate conditions	Bechtel PO-117820	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Containment Mini-Purge	Reduction of maximum allowed Containment pressure per NRC Plant Technical Specifications	Bechtel PO-117820	PSL License Amendment Request (LAR) Engineering
Feedwater Digital Modifications	Instrumentation to provide control the feedwater heater control and dump valves in the uprate conditions	Feedforward SC2287468	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Leading Edge Flow Meter (LEFM) Measurement Uncertainty Recapture (MUR)	Precision flow measurement instrument and instrumentation provides for increased certainty of operating parameters supporting uprate conditions	Cameron PO-116107	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Digital Electro-Hydraulic Computer System Modification	Modifications needed for increased certainty of turbine operating parameters supporting uprate conditions	Westinghouse Power PO-131940	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Electrical Bus Margin Modifications	Required to restore margin on electrical busses as a result of uprate	Bechtel PO-117820	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008

2012 Extended Power Uprate (EPU) Project Work Activities

St. Lucie Unit 1R24 2011/2012 Outage	Description	Contract	Scoping Document
Piping Vibration Modifications	Increases in steam and feedwater flows may cause piping vibrations. Restraints dampen the vibrations	Bechtel PO-117820	BOP analysis of component capabilities in the power uprate conditions
Main Generator Exciter Coolers/Blower	Increased cooling of the main generator exciter is required in the power uprate conditions	Siemens PO-116088	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Feedwater Heater Replacement (#5)	Larger feedwater heaters are needed to process the steam and feedwater flows in the uprate conditions	TEI PO-118224	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Feedwater Regulating Valves Modification	Larger operating mechanisms are required to operate the feedwater regulating valves in the increased uprate conditions	Fisher Controls SC2262515	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Main Generator Current Transformer and Bushing Replacement	Modifications required due to the modifications to the generator rotor and stator for uprate conditions	Siemens PO-116088	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Main Generator Hydrogen Seal Oil Pressure Increase	Increased hydrogen pressure for main generator cooling is required in the uprate conditions	Siemens PO-116088	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Main Generator Core Iron Replacement	Replace core iron to make the generator stator increased electrical output acceptable in the uprate conditions	Siemens	Testing of the main generator

2012 Extended Power Uprate (EPU) Project Work Activities

St. Lucie Unit 1R24 2011/2012 Outage	Description	Contract	Scoping Document
Main Generator Hydrogen Coolers	Increased main generator cooling is required in the uprate conditions	Siemens PO-116088	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Main Generator Rotor Replacement and Stator Rewind	Larger generator is needed to increase electrical output in the uprate conditions	Siemens PO-116088	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Moisture Separator Drain Control Valves Replacement	Larger valves are needed for the increased condensed water flow in the uprate conditions	Fisher Controls SC2262201	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Heater Drain Control Valves	Larger valves are needed to control the condensate flow in the uprate conditions	Fisher Controls SC2262201	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Feedwater Heater Drains/ Moisture Separator Reheater (MSR) Digital Controls	Reduce the operating band to optimize efficiency and maximize output	Bechtel PO-117820	St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Heater Drain Pumps and Motors Replacements	Larger pumps and motors are required to pump the increased heater drain flows in the uprate conditions	Flowserve Corp. PO- 125454	St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Hot Leg Injection Flow Improvements	Increasing required flow under EPU and eliminating single point failure vulnerability with cross train power on in-series valves	Bechtel PO-117820	EPU LAR Engineering
High Pressure Turbine Rotor	Larger inlet valves are required for increased steam flows in the uprate conditions	Siemens PO-116088	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, Balance of Plant, EPU, Scoping Study, February 2008

2012 Extended Power Uprate (EPU) Project Work Activities

St. Lucie Unit 1R24 2011/2012 Outage	Description	Contract	Scoping Document
Isophase Bus Duct Cooling	Increased cooling is needed for the electrical connections from the main generator to the main transformer in the uprate conditions	AZZ Calvert PO-120769	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Low Pressure (LP) Turbine Rotor	Larger LP turbine rotors are required for the increased steam flow in the uprate conditions	Siemens PO-116088	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Main Feedwater Pump Replacement	Larger pumps are required to pump the increased feedwater flow required in the uprate conditions	Flowserve PO-121985	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Main Steam Isolation Valve (MSIV) Modification	Larger operators on the MSIVs are required to operate against higher steam pressure	Enertech for Actuators	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Main Transformer Cooler Modification	Increased cooling is needed to handle the increase in the main generator electrical output	ABB PO-112255, 126248	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008, ABB Engineering Thermal Loading Design Study, FPL St. Lucie, ABB Project Number, FP13469-1, Rev.1, August 25, 2008
Main Steam, Condensate and Feedwater Piping Supports Modifications	Increased steam and water flows in the uprate conditions require additional piping restraints	Bechtel PO-117820	BOP analysis of component capabilities in the power uprate conditions

2012 Extended Power Uprate (EPU) Project Work Activities

St. Lucie Unit 1R24 2011/2012 Outage	Description	Contract	Scoping Document
Moisture Separator Reheater (MSR) Replacement	Larger capacity MSRs are required to heat and dry the steam flow in the uprate conditions	TEI PO-118205	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Control Element Drive Mechanism (CEDM) System Modifications	Modify the CEDM system to recover operational and safety margins in the uprate conditions	Westinghouse PO-118271	Original equipment manufacturer recommendation
Balance of Plant (BOP) Instrumentation	Setpoint and scaling of plant instrumentation for uprate conditions	Bechtel PO-117820	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Nuclear Steam Supply System Plant Instrumentation	Setpoint and scaling of plant instrumentation for uprate conditions	Bechtel PO-117820	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Safety Injection Tank Pressure Increase	Modification required to operate at higher pressure based on EPU conditions for small break Loss of Coolant Accident (LOCA) analysis	Bechtel PO-117820	EPU LAR Engineering
Steam Bypass Control System Unit 1 Distributed Control system (DCS)	Add digital controls to the increased steam bypass system flow	Invensys PO-2263052	Engineering Design Modifications
Steam Bypass Flow to Condenser-Increase	Increased steam flow in the uprate conditions requires larger bypass capability to the main condenser	Bechtel PO-117820	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Turbine Cooling Water Heat Exchanger Replacement	Larger heat exchangers are needed for increased cooling in the uprate conditions	TEI PO-118278	St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008

2012 Extended Power Uprate (EPU) Project Work Activities

St. Lucie Unit 1R24 2011/2012 Outage	Description	Contract	Scoping Document
Transmission and Substation (T&S) Modifications	At St. Lucie, metering and relay work, at Midway switchyard, switch replacement	T&S	Facilities Study, FPL EPU project, St. Lucie 1&2, Q114 & Q115, March 2009

2012 Extended Power Uprate (EPU) Work Activities

St. Lucie Unit 2R20 2012 Outage	Description	Contract	Scoping Document
Condensate Pump Replacement	Larger condensate pumps are needed to pump the increased condensate flows in the uprate conditions	Flowserve Corp. PO-130160	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, Balance of Plant (BOP), EPU, Scoping Study, February 2008
Condenser Material and Air Ejector Modification	Strengthening of the Main Condenser is needed with higher steam and condensate flows in the uprate conditions	Bechtel PO-117820	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Control Room Modification	Additional cooling and Alternative Source Term margin required for power uprate conditions	Bechtel PO-117820	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Digital Electro-Hydraulic Computer System Modification	Modifications needed for increased certainty of turbine operating parameters supporting uprate conditions	Westinghouse PO-131940	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Electrical Bus Margin Modifications	Required to restore margin on electrical busses as a result of uprate	Bechtel PO-117820	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Piping Vibration Modifications	Required to correct resistance caused by increased loads at EPU conditions	Bechtel PO-117820	BOP analysis of component capabilities under EPU conditions
Feedwater Heater ReplaBechtelcement (#5 A/B)	Larger feedwater heaters are needed to process the steam and feedwater flows in the uprate conditions	TEI PO-118224	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008

2012 Extended Power Uprate (EPU) Work Activities

St. Lucie Unit 2R20 2012 Outage	Description	Contract	Scoping Document
Feedwater Heaters 4A/B Replacement	Internal inspections determined needed for replacement to process the steam and feedwater flows in the uprate conditions	TEI SC2297055	BOP analysis of component capabilities in the power uprate conditions
Feedwater Regulating Valves Modification	Larger operating mechanisms are required to operate the feedwater regulating valves in the increased uprate conditions	Fisher Controls SC2262515	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Heater Drain and Moisture Separator Drain Control Valves Replacement	Larger valves are needed for the increased condensed water flow in the uprate conditions	Fisher Controls SC2262201	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Feedwater / Heater Drain/MSR Digital Controls	Instrumentation and digital controls to the feedwater heater control and dump valves, new MSRs and Drain Coolers due to EPU conditions	Feedforward SC2287468	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Heater Drain Pump Replacement	Larger pumps are required to pump the increased heater drain flows in the uprate conditions	Flowserve Corp. PO- 125454	St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
High Pressure (HP) Turbine	Larger HP rotor and inlet valves are required for increased steam flows in the uprate conditions	Siemens PO-116088	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, Balance of Plant, EPU, Scoping Study, February 2008

2012 Extended Power Uprate (EPU) Work Activities

St. Lucie Unit 2R20 2012 Outage	Description	Contract	Scoping Document
Isophase Bus Duct Cooling	Increased cooling is needed for the electrical connections from the main generator to the main transformer in the uprate conditions	AZZ Calvert PO-120769	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Leading Edge Flow Meter (LEFM) Measurement Uncertainty Recapture (MUR)	Precision flow measurement instrument and instrumentation provides for increased certainty of operating parameters supporting uprate conditions	Cameron PO-116107	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Main Feedwater Pump Replacement	Larger pumps are required to pump the increased feedwater flow required in the uprate conditions	Flowserve PO-121985	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Main Transformer Replacement	Larger main transformers are needed to handle the increase in the main generator electrical output	Siemens PO-4500467077	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Main Steam, Condensate, and Feedwater Piping Support Modifications	Strengthening required due to increased loads under EPU conditions	Bechtel PO-117820	BOP analysis of component capabilities under power uprate conditions
Moisture Separator Reheater (MSR) Replacement	Larger capacity MSRs are required to heat and dry the steam flow in the uprate conditions	TEI PO-118205	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008

2012 Extended Power Uprate (EPU) Work Activities

St. Lucie Unit 2R20 2012 Outage	Description	Contract	Scoping Document
Balance of Plant (BOP) and Nuclear Steam Supply System (NSSS) Plant Instrumentation	Set point and scaling of plant instrumentation for uprate conditions	Bechtel PO-117820	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Increase Steam Bypass Flow to Condenser Modifications	Modifications required due to increased bypass flow to condenser from main steam, feedwater and heater drains	Bechtel PO-117820	EPU License Amendment Request (LAR) Engineering
Turbine Cooling Water Heat Exchanger Replacement	Larger heat exchangers are needed for increased cooling in the uprate conditions	TEI PO-118278	St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Chemical Volume Control system (CVCS) Mod for Gas Collection	NRC Generic Letter (GL2008-01) requires licensees to ensure emergency systems are capable of being vented at their water high points to minimize air entrapment when the system is required to function	Alion 129895	Identified during the LAR engineering review
Component Cooling Water (CCW) Piping & Support Modifications	Strengthening required due to increased thermal conditions under EPU	Bechtel PO-117820	BOP analysis of component capabilities under power uprate conditions
Environmental Qualification (EQ) Equipment Mods - Containment Temperature Resistance Temperature Detector (RTD) Modifications	Existing RTDs not EQ related components. EPU conditions subject these components to more harsh environment	Bechtel PO-117820	EPU LAR Engineering

2012 Extended Power Uprate (EPU) Work Activities

St. Lucie Unit 2R20 2012 Outage	Description	Contract	Scoping Document
Feedwater Vent Orifice & Relief Valve Resizing	Feedwater Heater Shell Side must be capable of relieving 10% of FW flow under EPU conditions	Bechtel PO-117820	BOP analysis of component capabilities under power uprate conditions
Containment Spray Pump Flow Impact Modifications	EDG frequency deviation for EPU conditions impacts ability of pumps to operate under injection and recirculation modes. Replacement impellers and throttling bypass valves required	Bechtel PO-117820	EPU LAR Engineering
Isophase Bus Supports	Bus taps to Aux and Start-Up transformers are undersized and under-supported for short circuit under EPU conditions	Bechtel PO-117820	EPU LAR Engineering
Distributed Control System for LEFM and Feedwater Controls	Mandatory scaling changes required to provide accurate control under EPU conditions	Feedforward SC2287468	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Diesel Oil Storage Tank (DOST) Operating Margin Modification	EPU required DOST capacity. Need loop seals in the fill & overflow lines	Bechtel PO-117820	EPU LAR Engineering
Control Element Drive Mechanism (CEDM) System Modifications	Modify the CEDM system to recover operational and safety margins in the uprate conditions	Westinghouse PO-118271	OEM Recommendation

2012 Extended Power Uprate (EPU) Work Activities

St. Lucie Unit 2R20 2012 Outage	Description	Contract	Scoping Document
Umbrella Modification "EPU Wrap-up"	Provides the basis for plant to go to EPU conditions. Wraps up all modifications, assesses all systems, updates misc procedures, Final Safety Analysis Report, etc	Shaw PO-112221	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Charging Pump Safety Injection Actuation Signal (SIAS) Circuit Change	The Unit 2 Charging Pumps, which are now credited for Emergency Core Cooling Sytem Small Break Loss of Coolant Accident for EPU conditions, trip on SIAS	Bechtel PO-117820	Station Engineering identified this SIAS trip must be removed for Accident conditions.

2012 Extended Power Uprate (EPU) Work Activities

St. Lucie Unit 2R20 2012 Outage	Description	Contract	Scoping Document
Low Pressure (LP) Turbine Torsional Tuning	During LP Turbine torsional monitoring in SL2-19 power ascension, the machine operating frequency was found to pass through the "double line" resonant frequency, making it susceptible to negative sequence induced, outer blade vibration damage. To drive this frequency outside of this range (to meet Nuclear Electric Insurance Limited (NEIL) req'ts), the tuning option installs a less stiff jackshaft between the two LPs, thereby pushing the machine frequency safely below the resonant frequency	Siemens PO-116088	OEM Recommendation

2012 Extended Power Uprate (EPU) Work Activities

St. Lucie 2012 On-Line Activities	Description	Contract	Scoping Document
Training Simulator Modifications	Modifications needed to replicate the plant in the power uprate conditions	Western Services Corp. PO-118627	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008
Spent Fuel Pool (SFP) Modifications	Regulatory driven modification for more highly enriched fuel required for EPU	Holtec PO-2291586	EPU LAR Engineering

2012 Extended Power Uprate (EPU) Project Work Activities

Turkey Point Unit 3R26 2012 Outage	Description	Final Contract	Scoping Document
Sump pH Control, Install Sodium Pentaborate (NaTB) Baskets	Alternative Source Term method requires pH greater than 7.0. The current pH control system is not sufficient at uprate conditions	S&L PO-79551	AST LAR Engineering
Feedwater Heater Drains of Digital Modifications	Instrumentation to provide control the feedwater heater level control and dump valves in the uprate conditions	Invensys PO -126227	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Turbine Digital Controls Modification – Units 3 & 4	Enhanced controls for the new turbines. Current design is not sufficient for the new turbine configuration in the uprate conditions	Invensys PO-129689	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Leading Edge Flow Meter (LEFM) Digital upgrade Phase 3 (Instrumentation)	Precision flow measurement instrument and instrumentation provides for increased certainty of operating parameters supporting uprate conditions	Cameron PO-116796	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Isophase Bus Duct Replacement	Increased bus size is needed for the electrical connections from the main generator to the main transformer in the uprate conditions	AZZ / Calvert PO-124436	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
BOP Instrumentation Modifications	Increased pressures and flows require modifications and adjustments to process instrumentation in the uprate conditions	Bechtel PO-117809	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008

2012 Extended Power Uprate (EPU) Project Work Activities

Turkey Point Unit 3R26 2012 Outage	Description	Final Contract	Scoping Document
Switchyard Modifications	Increased electrical output requires modification to switchyard equipment to support the uprate conditions	T & S	Generation Interconnection Service and Network Resource Interconnection Service System Impact Study. 11/25/08
Fast Acting Feedwater Isolation Valves Addition	Increased feedwater flow and pressure requires modifications to support uprate conditions	Bechtel PO-117809	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Feedwater Regulating Valves Trim Upgrade Modification	Larger actuators and valve internals are required to operate the feedwater regulating valves in the increased uprate conditions	SPX PO-115351	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Heater Drain Valves (Remaining)	Larger valves are needed to control the condensate flow in the uprate conditions	Bechtel PO-117809	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Feedwater Heater #5 Drain Piping Modification	Higher drain water flows require larger piping in the uprate conditions	Bechtel PO-117809	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Main Steam Isolation Valve and Main Steam Control Valve Assemblies (MSIV/MSCV) Replacement	Satisfies new steam system pressure requirements at the HP turbine	Bechtel PO-117809	EPU LAR Engineering
Main Steam Safety Valve Set Point Modifications	Increased temperature and pressure require set point changes in the uprate conditions	Bechtel PO-117809	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Flow Accelerated Corrosion Identified Piping Replacement Phase B	Increased flows require replacement of piping affected by the flow accelerated corrosion in the uprate conditions	Bechtel PO-117809	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008

2012 Extended Power Uprate (EPU) Project Work Activities

Turkey Point Unit 3R26 2012 Outage	Description	Final Contract	Scoping Document
High Pressure Turbine Modification	Larger inlet throttle valves and Turbine redesign are required for increased steam flows in the uprate conditions	Siemens PO-116090	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Main Generator Rotor Replacement	Larger generator and stator are needed to increase electrical output in the uprate conditions	Siemens PO-116090	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Main Generator Hydrogen Coolers	Increased main generator cooling is required in the uprate conditions	Siemens PO-116090	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Turbine Electro-Hydraulic Controls	Enhanced controls for the new turbines. Current design is not sufficient for the new turbine configuration in the uprate conditions	Siemens PO-130272	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Moisture Separator Reheater (MSR) Replacement	Larger capacity MSRs are required to heat and dry the steam flow in the uprate conditions	TEI PO-118206	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Main Condenser replacement	Increased turbine exhaust steam to the main condenser requires replacement of the main condenser to support uprate conditions	TEI PO-118328	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Condenser Tube Cleaning System (Amertap)	Replacement of the main condenser requires replacement of the condenser tube cleaning system to support the uprate conditions	TEI PO-118328	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008

2012 Extended Power Uprate (EPU) Project Work Activities

Turkey Point Unit 3R26 2012 Outage	Description	Final Contract	Scoping Document
Normal Containment Cooling (NCC) Modifications	Increased power production from the primary system requires additional cooling of the containment in the uprate conditions	AAF McQuay PO-121869	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Spent Fuel Pool (SFP) Cooling Heat Exchanger Modification	Increased power from the fuel requires additional cooling of the fuel when it is placed into the SFP	Joseph Oats PO-2259675	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Pressurizer Safety Valve Setpoint Change	A Pressurizer Safety Valve Setpoint change is required to meet the peak Reactor Coolant System pressure in the analyzed Loss of Level/Turbine Trip (LOL/TT) event	Bechtel PO-117809	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Emergency Containment Filter Removal	Abandon containment filters from the containment to support the safety margin in the uprate conditions.	Bechtel PO-117809	FPL PTN Feasibility Study 2007
Condensate Pump and Motor Replacement	Larger condensate pumps are needed to pump the increased condensate flows in the uprate conditions	Flowserve PO-130612	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Main Feed Pump Rotating Element Replacement	Rotating assemblies need redesign to pump the increased feedwater flow required in the uprate conditions	Flowserve PO-130612	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Turbine Plant Cooling Water (TPCW) HX Replacement	Increased temperatures of components require additional cooling in the uprate conditions	Joseph Oat Corp. PO-126453	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Feedwater Heaters (5A/B, 6A/B) Replacement	Larger feedwater heaters are needed to process the steam and feedwater flows in the uprate conditions	TEI PO-118241	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008

2012 Extended Power Uprate (EPU) Project Work Activities

Turkey Point Unit 3R26 2012 Outage	Description	Final Contract	Scoping Document
Instrumentation & Control Pressurizer Setpoint / Control / Indication Changes	Changes to NSSS and BOP instrumentation are required to meet EPU conditions	Bechtel PO-117809	EPU LAR Engineering
Main Steam Pressure Lead/Lag Module Install and Eagle 21 Changes	Modifications for licensing, design basis, plant program changes, I&C scaling and setpoint changes identified to support EPU conditions	Westinghouse PO-119078	EPU LAR Engineering
Main Steam Pipe Snubber and Supports Installation	Uprate conditions require additional piping supports and restraints	Bechtel PO-117809	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
High Pressure Turbine Supply Spill Over Piping Replacement	Modifications needed for increased HP Turbine exhaust pressures and spillover	Bechtel PO-117809	EPU LAR Engineering
Secondary Instrumentation Set point and indication Changes	Changes to NSSS and BOP instrumentation are required to meet EPU conditions	Bechtel PO-117809	EPU LAR Engineering
Containment Aluminum Reduction	EPU increases containment sump temperature which accelerates aluminum degradation	Zachry PO 115465	EPU LAR Engineering
Hot Leg Injection Alternate Flow Path	Evaluate/modify current design for alternate Hot Leg flow path which contains a single-failure deficiency for post-Loss of Coolant Accident (LOCA) Hot Leg Recirculation	Bechtel PO-117809	EPU LAR Engineering
Plant Documentation Changes resulting from Westinghouse Setpoint and Scaling Changes	Documentation update and identification of setpoint / scaling changes to plant computer systems software for NSSS systems as a result of EPU	Bechtel PO-117809	EPU LAR Engineering

2012 Extended Power Uprate (EPU) Project Work Activities

Turkey Point Unit 3R26 2012 Outage	Description	Final Contract	Scoping Document
Main Steam Flow Element Replacement	Satisfies new steam system pressures requirements at the HP turbine	Bechtel PO-117809	EPU LAR Engineering
Steam Generator Blowdown Flow Instrumentation Modifications	Modifications needed to improve measurement accuracy of Steam Generator blowdown	Bechtel PO-117809	EPU LAR Engineering
Closed Cooling Water (CCW) Pipe Support Modifications	CCW Pipe Supports need to be evaluated/modified to ensure design basis is met under EPU conditions	Bechtel PO-117809	EPU LAR Engineering
Steam Jet Air Ejector Condenser Tube Bundle Replacement	Modification needed to SJAE condenser due to increased condensate system pressure resulting from uprate	WeldTech P.O. 2304432	EPU LAR Engineering
Heater Drain System Pressure Re-rate	Piping modifications required to meet EPU conditions	Bechtel PO-117809	EPU LAR Engineering
Control Rod Drive Mechanism Fan Motor and Cooling Coil Replacement	Fan motor modification needed because of increased containment temperatures caused by EPU conditions. Cooling coil material being changed to copper to reduce the amount of aluminum in containment to meet AST requirements	Bechtel PO-117809	AST LAR Engineering
Repowering of the Alternate PTN Unit 4 Spent Fuel Pool (SFP) Cooling Pump Motor	Increased heat load on the SFP cooling system due to EPU conditions requires a 2nd cooling pump to be in operation	Bechtel PO-117809	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008

2012 Extended Power Uprate (EPU) Project Work Activities

Turkey Point Unit 3R26 2012 Outage	Description	Final Contract	Scoping Document
Emergency Containment Cooling (ECC) Restore Automatic Actuation of Third ECC to Reduce Containment Pressure	Auto actuation of the three Emergency Containment Cooling fans is required in the uprate conditions	Enercon P.O. 2294494	EPU LAR Engineering
EPU Piping Vibration Modification	Piping will be monitored for increased vibrations which may require additional modifications to piping constraints in the uprate condition	Shaw Eng PO 2296076	Operating Experience from uprates

2012 Extended Power Uprate (EPU) Project Work Activities

Turkey Point Unit 4 2012/2013 Outage	Description	Final Contract	Scoping Document
Sump pH Control, Install Sodium Tetraborate (NaTB) Baskets	Alternative Source Term (AST) method requires pH greater than 7.0. The current pH control system is not sufficient at uprate conditions	S&L PO-79551	AST LAR Engineering
Switchyard Modifications	Increased electrical output requires modification to switchyard equipment to support the uprate conditions	T & S	Generation Interconnection Service and Network Resource Interconnection Service System Impact Study. 11/25/08
Feedwater Heater Drains Digital Modifications	Instrumentation to provide control the feedwater heater control and dump valves in the uprate conditions	Bechtel PO-117809	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Turbine Digital Controls Modification	Enhanced controls for the new turbines. Current design is not sufficient for the new turbine configuration in the uprate conditions	Bechtel PO-117809	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Leading Edge Flow Meter (LEFM) Digital (Instrumentation) Upgrade Tie In	Precision flow measurement instrument and instrumentation provides for increased certainty of operating parameters supporting uprate conditions	Bechtel PO-117809	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
BOP Instrumentation Modifications	Increased pressures and flows require modifications and adjustments to process instrumentation in the uprate conditions	Ames PO-2302164	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008

2012 Extended Power Uprate (EPU) Project Work Activities

Turkey Point Unit 4 2012/2013 Outage	Description	Final Contract	Scoping Document
Fast Acting Feedwater Isolation Valves Addition	Increased feedwater flow and pressure requires modifications to support uprate conditions	Bechtel PO-117809	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Feedwater Regulating Valves Trim Upgrade Modification	Larger actuators and valve internals are required to operate the feedwater regulating valves in the increased uprate conditions	SPX PO-115351	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Heater Drain Valves Replacement (Remaining)	Larger valves are needed to control the condensate flow in the uprate conditions	Bechtel PO-117809	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Feedwater Heater #5 Drain Piping Modification	Higher drain water flows require larger piping in the uprate conditions	Bechtel PO-117809	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Main Steam Isolation Valve and Main Steam Control Valve Assemblies (MSIV/MSCV) Replacement	Satisfies new steam system pressures requirements at the HP turbine	Bechtel PO-117809	EPU LAR Engineering
Main Steam Safety Valve Set Point Modifications	Increased temperature and pressure require set point changes in the uprate conditions	Ames PO-2302164	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
High Pressure Turbine Modification	Larger inlet throttle valves and Turbine redesign are required for increased steam flows in the uprate conditions	Siemens PO-116090	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Main Generator Rotor Replacement	Larger generator and stator are needed to increase electrical output in the uprate conditions	Siemens PO-116090	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008

2012 Extended Power Uprate (EPU) Project Work Activities

Turkey Point Unit 4 2012/2013 Outage	Description	Final Contract	Scoping Document
Main Generator Hydrogen Coolers	Increased main generator cooling is required in the uprate conditions	Siemens PO-116090	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Turbine Electro-Hydraulic Controls	Enhanced controls for the new turbines. Current design is not sufficient for the new turbine configuration in the uprate conditions	Siemens PO-130272	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Moisture Separator Reheater (MSR) Replacement	Larger capacity MSRs are required to heat and dry the steam flow in the uprate conditions	Bechtel PO-117809	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Main Condenser replacement	Increased turbine exhaust steam to the main condenser requires replacement of the main condenser to support uprate conditions	Bechtel PO-117809	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Condenser Tube Cleaning System Replacement (Amertap)	Replacement of the main condenser requires replacement of the condenser tube cleaning system to support the uprate conditions	Bechtel PO-117809	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Normal Containment Cooling (NCC) Modifications	Increased power production from the primary system requires additional cooling of the containment in the uprate conditions	Shaw PO-2293489	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Spent Fuel Pool Cooling Heat Exchanger Replacement	Increased power from the fuel requires additional cooling of the fuel when it is placed into the spent fuel pool	PCI PO-2309693	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008

2012 Extended Power Uprate (EPU) Project Work Activities

Turkey Point Unit 4 2012/2013 Outage	Description	Final Contract	Scoping Document
Pressurizer Safety Valve Setpoint Change	A Pressurizer Safety Valve Setpoint change is required to meet the peak Reactor Coolant System pressure in the LOL/TT event	Ames PO-2302164	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Emergency Containment Filter Removal	Abandon containment filters from the containment to support the safety margin in the uprate conditions	Shaw PO-2293489 R7	FPL PTN Feasibility Study 2007
Condensate Pump and Motor Replacement	Larger condensate pumps are needed to pump the increased condensate flows in the uprate conditions	Bechtel PO-117809	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Main Feed Pump Rotating Element Replacement	Rotating assemblies need redesign to pump the increased feedwater flow required in the uprate conditions	Bechtel PO-117809	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Turbine Plant Cooling Water (TPCW) Heat Exchanger Replacement	Increased temperatures of components require additional cooling in the uprate conditions	Bechtel PO-117809	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Feedwater Heaters (5A/B, 6A/B) Replacement	Larger feedwater heaters are needed to process the steam and feedwater flows in the uprate conditions	Bechtel PO-117809	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Main Steam Pressure L/L Module Install and Eagle 21 Changes	Modifications for licensing, design basis, plant program changes, I&C scaling and setpoint changes identified to support EPU conditions	Ames PO-2302164	EPU LAR Engineering
Pressurizer Setpoint / Control / Indication Changes	Changes to NSSS and BOP instrumentation are required to meet EPU conditions	Ames PO-2302164	EPU LAR Engineering

2012 Extended Power Uprate (EPU) Project Work Activities

Turkey Point Unit 4 2012/2013 Outage	Description	Final Contract	Scoping Document
Main Steam Pipe Snubber and Supports Installation	Uprate conditions require additional piping supports and restraints	Shaw PO-2293489 R7	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
High Pressure Turbine Supply Spill Over Piping Replacement	Modifications needed for increased HP Turbine exhaust pressures and spillover	WeldTech PO-2304432	EPU LAR Engineering
Secondary Instrumentation Setpoint Changes	Changes to NSSS and BOP instrumentation are required to meet EPU conditions	Ames PO-2302164	EPU LAR Engineering
Containment Aluminum Reduction	EPU increases containment sump temperature which accelerates aluminum degradation	Shaw PO-2293489 R7	EPU LAR Engineering
Hot Leg Injection Alternate Flow Path	Evaluate/modify current design for alternate Hot Leg flow path which contains a single-failure deficiency for post-LOCA Hot Leg Recirculation	Shaw PO-2293489 R7	EPU LAR Engineering
Plant Doc Changes resulting from Westinghouse Setpoint and Scaling Changes	Documentation update and identification of setpoint / scaling changes to plant computer systems software for NSSS systems as a result of EPU	Ames PO-2302164	EPU LAR Engineering
Main Steam Flow Element Modifications	Satisfies new steam system pressures requirements at the HP turbine	Shaw PO-2293489 R7	EPU LAR Engineering
Steam Generator Blowdown Flow Instrumentation	Modifications needed to improve measurement accuracy of Steam Generator blowdown	Bechtel PO-117809	EPU LAR Engineering

2012 Extended Power Uprate (EPU) Project Work Activities

Turkey Point Unit 4 2012/2013 Outage	Description	Final Contract	Scoping Document
Closed Cooling Water (CCW) Pipe Support Modifications	CCW Pipe Supports need to be evaluated/modified to ensure design basis is met under EPU conditions	Shaw PO-2293489 R7	EPU LAR Engineering
Steam Jet Air Ejector (SJAE) Condenser Tube Bundle Replacement	Modification needed to SJAE condenser due to increased condensate system pressure resulting from uprate	WeldTech PO-2304432	EPU LAR Engineering
Heater Drain System Pressure Re-rate	Piping modifications required to meet EPU conditions	Bechtel PO-117809	EPU LAR Engineering
Control Rod Drive Mechanism Fan Motor and Cooling Coil Replacement	Fan motor modification needed because of increased containment temperatures caused by EPU conditions. Cooling coil material being changed to copper to reduce the amount of aluminum in containment to meet AST requirements	Shaw PO-2293489 R7	AST LAR Engineering
Emergency Containment Coolers (ECC) Restore Automatic Actuation of Third ECC to Reduce Containment Pressure	Auto actuation of the three Emergency Containment Cooling fans is required in the uprate conditions	Shaw PO-2293489 R7	EPU LAR Engineering
EPU Piping Vibration Modification	Piping will be monitored for increased vibrations which may require additional modifications to piping constraints in the uprate condition	Shaw PO-2293489 R7	Operating Experience from uprates
Unit 4 Turbine Building& Feedwater Platform Structure	Provide additional structural support for heavier components	Bechtel PO-117809	Engineering Evaluation

2013 Extended Power Uprate (EPU) Project Work Activities

Turkey Point 2013 On-Line Activities	Description	Final Contract	Scoping Document
Post EPU Condenser Amertap Cleaning System Units 3 & 4	Replacement of the main condenser requires replacement of the condenser tube cleaning system to support the Uprate conditions	Bechtel PO-117809	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008
Add Valve Operator Extension Hand wheel to Safety Injection Valve 3-867 and 4-867	Modification makes motor operated valve accessible to allow manual isolation to accommodate EPU conditions	Shaw P.O. 2293489 R7	EPU LAR Engineering
Unit 4 Umbrella Modification LAR Document PCM # 1	Non-hardware modifications implementing configuration management of licensing, design basis and plant program changes as a result of EPU	Enercon PO-2285720	EPU LAR Engineering
Unit 4 Condensate Polishing	Condensate Polishing building modification to clean secondary water after major component replacements	Shaw P.O. 2293489 Release 007	Engineering evaluation and operating experience
Site Demobilization and Site Restoration	Restoration of temporary facilities, structures, parking, construction, return office areas to pre-EPU Project conditions	Various	Engineering Modifications and FPSC Nuclear Cost recovery
Post -EPU Asset Disposal	Demolition and disposal of all construction debris, replaced vessels and components	Various	Engineering Modifications and FPSC Nuclear Cost recovery

2013 Extended Power Uprate (EPU) Project Work Activities

Turkey Point 2013 On-Line Activities	Description	Final Contract	Scoping Document
Post EPU Outage System Testing and Tuning	To align systems to optimal performance and re-establishes performance baselines for systems that were modified	Various	FPL PTN Feasibility Study 2007, Turkey Point Nuclear Plant BOP EPU Scoping Study, March 2008 and Engineering Modifications
Final Project Documentation and Close-out	Project document close-out activities which include calculation updates, Configuration Control Programs, Document Package Closeout and commercial close-out	Various	FPL Feasibility Study 2007, Turkey Point Nuclear Plant, BOP, EPU, Scoping Study, February 2008 and Engineering modifications
Cost Recovery Close-out	Provide support and documentation for final close-out of Cost Recovery process	Various	FPSC Nuclear Cost Recovery

2013 Extended Power Uprate (EPU) Project Work Activities

St. Lucie Plant 2013 On-Line Activities	Description	Final Contract	Scoping Document
Site Demobilization and Site Restoration	Restoration of temporary facilities, structures, parking, construction, return office areas to pre-EPU Project conditions	Various	Engineering Modifications and FPSC Nuclear Cost recovery
Post EPU Asset Disposal	Demolition and disposal of all construction debris, replaced vessels and components	Various	Engineering Modifications and FPSC Nuclear Cost recovery
Post EPU Outage System Testing and Tuning	To align systems to optimal performance and re-establishes performance baselines for systems that were modified	Various	FPL PSL Feasibility Study 2007, St. Lucie Nuclear Plant BOP EPU Scoping Study, March 2008 and Engineering Modifications
Final Project Documentation Close-out	Project document close-out activities which include calculation updates, Configuration Control Programs, Document Package Closeout and commercial close-out	Various	FPL Feasibility Study 2007, St. Lucie Nuclear Plant, BOP, EPU, Scoping Study, February 2008 and Engineering modifications
Cost Recovery Close-out	Provide support and documentation for final close-out of Cost Recovery process	Various	FPSC Nuclear Cost Recovery

EQUIPMENT PLACED IN SERVICE IN 2012

Item No.	EPU Assets Placed in Service in 2012	Date Placed In Service
1	Nuclear - Turkey Point Distribution Heavy Haul Path	January 2012
2	Transmission - St. Lucie Midway Substation Line Bay Upgrade	March 2012
3	Transmission - St. Lucie Generator Bay Upgrade	March 2012
4	Nuclear - St. Lucie Unit 1 Outage (PSL 1-24) 1. Feedwater Pump Replacement 2. Low Pressure and High Pressure Turbine Rotors Replacement 3. Generator Upgrade Rotor Replacement & Stator Rewind 4. Generator Current Transformers and Bushings Replacement 5. Generator Hydrogen Seal Oil System Pressure Increase 6. Generator Hydrogen Coolers Upgrade 7. Generator Exciter Cooler Upgrade 8. Heater Drain Pump and Valve Replacement 9. Turbine Plant Cooling Water Heat Exchanger Replacement 10. Main Steam Isolation Valve Modification 11. Condenser Air Removal System Upgrade 12. Isophase Bus Duct Cooling Modification 13. Steam Bypass Control System Upgrade 14. Moisture Separator Reheater Replacement 15. Feedwater Heater # 5 Replacement	April 2012
5	GSU - St. Lucie Unit 1 Generator Step-Up (GSU) Transformer Cooler Upgrade	April 2012
6	Transmission - Turkey Point Site Expansion Switchyard	June 2012
7	Transmission - Turkey Point Davis Breaker Failure Panels	July 2012
8	Nuclear - St. Lucie Unit 1 License Amendment Request	July 2012
9	Transmission - Turkey Point Flagami Breaker Failure Panels	July 2012
10	Transmission - Turkey Point Distribution Street Lighting	August 2012
11	GSU - Turkey Point Spare Generator Step-Up (GSU) Transformer	August 2012

Item No.	EPU Assets Placed in Service in 2012	Date Placed In Service
12	Nuclear - Turkey Point Turbine Valve Refurbishment (from PTN 4-26)	August 2012
13	Nuclear - Turkey Point Unit 3 Outage (PTN 3-26) 1. High Pressure Turbine Rotor Replacement 2. Generator Upgrade - Rotor Replacement & Stator Rewind 3. Generator Current Transformers and Bushings Replacement 4. Generator Hydrogen Coolers Upgrade 5. Generator Exciter Cooler Upgrade 6. Heater Drain Pump and Valve Replacement 7. Spent Fuel Cooling Heat Exchanger Replacement 8. Main Steam Isolation Valve Modification 9. Moisture Separator Reheater Replacement 10. Isophase Bus Duct Cooling Modification 11. Steam Bypass Control System Upgrade 12. Turbine Plant Cooling Water Heat Exchanger Replacement 13. Main Condenser Replacement 14. Normal Containment Cooling Modification 15. Condensate Pump and Motor Replacement 16. Feedwater Heater # 5 & 6 Replacement	September 2012
14	Nuclear - Turkey Point Unit 3 and 4 License Amendment Request	September 2012
15	Nuclear - Turkey Point Turbine Valve Refurbishment (during PTN 3-26)	September 2012
16	Nuclear - Turkey Point Simulator	September 2012
17	Nuclear - St. Lucie Unit 2 Outage (PSL 2-20) 1. Condensate Pump Replacement 2. High Pressure Turbine Rotor Replacement 3. Heater Drain Pump and Valve Replacement 4. Turbine Plant Cooling Water Heat Exchanger Replacement 5. Condenser Air Removal System Upgrade 6. Isophase Bus Duct Cooling Modification 7. Steam Bypass Control System Upgrade 8. Feedwater Heater # 4 & 5 Replacement 9. Moisture Separator Reheater Replacement	November 2012
18	Nuclear - St. Lucie Unit 2 License Amendment Request	November 2012
19	GSU - St. Lucie Unit Replacement 2A Generator Step-Up (GSU) Transformer	November 2012
20	Nuclear - Turkey Point Gate Valve Machining	November 2012

Item No.	EPU Assets Placed in Service in 2012	Date Placed In Service
21	Nuclear - Turkey Point Globe Valve Machining	November 2012
22	Transmission - Turkey Point Switchyard	November 2012
23	GSU - St. Lucie Spare Generator Step-Up (GSU) Transformer Coolers & Pumps	November 2012
24	Nuclear - Turkey Point Turbine Valve Refurbishment (from PTN 3-26)	December 2012

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EPU Project Instructions (EPPI) Index as of December 31, 2012

Title	PI #	Revs	Issued
Project Administration	**100**		
Project Instruction Preparation, Revision, Cancellation	100	R6	10/22/2012
EPU Project Expectations & Conduct of Business	110	R26	10/8/2012
Roles & Responsibilities	140	R11	9/11/2012
EPU Project-Nuclear Business Ops Interface	150	R3	5/16/2012
EPU Project Formal Correspondence	160	R3	12/22/2011
Time and Expense Reporting to FPLE Support	170	Cancelled	5/7/2012
EPU Nuclear Cost Recovery	180	R2	10/22/2012
Human Performance	190	R0	4/2/2012
Procurement	**200**		
PR and PO Funding Request and Single/Sole Source Justification	220	R6	7/25/2012
Project Invoice Process Instructions	230	R8	10/8/2012
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EPU Contract Compliance Program	240	R4	2/29/2012
Project Target Price Control Process	250	Cancelled	10/22/2012
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EPU Project Change Control	300	R10	12/6/2010
Forecast Variance and Trends	301	R1	11/28/2011
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Development, Maintenance, and Update of Schedules	310	R6	5/5/2011
Cost Estimating	320	R3	6/18/2012
EPU Project Risk Management Program	340	R5	12/22/2011
EPU LAR Engineering Risk Management	345	Cancelled	5/18/2011
FPL Accrual Process	370	R5	1/30/2012
Project Self Assessment	380	R2	3/28/2011
EPU Obsolete and Spare Parts Process Guideline	391	R0	3/28/2011
Project Training	**500**		
EPU Project Personnel Training Requirements	520	R2	7/20/2011
EPU Project Qualification Guidelines	560	R4	1/3/2011
Quality, Engineering & Licensing	**600**		
EPU Uprate License Amendment Request	610	Cancelled	7/28/2011
Request for Information - St. Lucie and Turkey Point	640	R1	12/4/2011
Saint Lucie Specific	**800**		
St. Lucie EPU Project Severe Weather Preparation	810	R4	4/11/2012
EPU Project Environmental Control Program PSL	820	Cancelled	12/12/2012
Turkey Point Specific	**900**		
Turkey Point EPU Project Severe Weather Preparations	910	R1	6/1/2010
EPU Project Environmental Control Program PTN	920	Cancelled	4/26/2012

Extended Power Uprate Project Reports 2012

Report	**Report Description**	**Typical Periodicity**	**Audience**
PTN Daily Report	Activities scheduled within the next six weeks	Daily	All project staff personnel, project management and project controls
Juno Beach, Executive VP & Chief Nuclear Officer Summary	LAR status, engineering status, planning and implementation, and project risks	Biweekly	Executive Vice president & Chief Nuclear Officer and other invited guests
PSL, PTN, Accrual Report	Documents accruals for each site, vendor, amount, purchase order, remarks and references	Monthly	Nuclear Business Operations, Corporate accounting, EPU Project Management
PSL, PTN Variance Report	Cost actuals, budgets and forecasts for Operations & Maintenance (O&M) and Capital expenditures	Monthly	Nuclear Business Operations, Corporate accounting, EPU Project Management
PSL, PTN, Monthly Operating Performance Report (MOPR)	Dashboard of EPU project, scope definition, execution plan, resources, cost, schedule, quality, safety, environmental, licensing, and regulatory	Monthly	Executive Management, EPU Project Management
PSL, PTN Risk Matrix	Quantified risks, potential cost impact, weighted cost impact, probability of occurrence, and risks identified but not quantified	PTN Weekly PSL As Needed	Project Management, Input to Presentations

Extended Power Uprate Project Reports 2012 (continued)

Report	Report Description	Typical Periodicity	Audience
PSL, PTN Monthly Cash Flow Charts	Dashboard, progress indicators, resources, schedule, and costs	Monthly	Project Management
Juno Beach, Executive Steering Committee Meeting Presentations	Project status, indicators, forecast issues, next steps	Quarterly	Executive Management
Bechtel Status Report	Dashboard, progress indicators, resources, schedule, costs	As needed	Project Management
Juno Beach, Key Supplier Meeting	Work scope status reports	As needed	Executive and Project Management
Bechtel, PTN	Daily Earned Value Report and Daily Cost Report for PTN 4R27 outage	Daily	Project Management, Input to Presentations
Shaw, PTN	Daily Earned Value Report and Daily Cost Report for PTN 4R27 outage	Daily	Project Management, Input to Presentations
Bechtel	Trend Register	Weekly	Project Management, Input to Presentations

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Category	2012 Actual Costs
Licensing	$50,526,559
Engineering & Design	$30,475,285
Permitting	$0
Project Management	$57,105,177
Power Block Engineering, Procurement, etc.	$1,251,631,758
Non-Power Block Engineering, Procurement, etc.	$1,673,642
Total EPU Construction Capital Costs	**$1,391,412,421**
Transmission Capital	$29,715,008
Total Construction & Transmission Capital Costs	**$1,421,127,429**
EPU Recoverable O&M	$7,788,763
Total Construction & Transmission Costs	**$1,428,916,192**

Table includes post in-service costs. NFR Schedules T4, O&M and T6, Construction and Transmission costs do not.